JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2009	)	Docket No.
Integrated Energy Policy Report	)	09-IEP-1K
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, APRIL 15, 2009

8:30 A.M.

ORIGINAL

Reported by:
John Cota
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COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member,
Integrated Energy Policy Report Committee

James D. Boyd, Vice Chairman and Associate Member,
Integrated Energy Policy Report Committee and
Presiding Member, Transportation Committee

ADVISORS PRESENT

Susan Brown

Kristy Chew

Diana Schwyzer

STAFF and CONTRACTORS PRESENT

Nick Janusch

Suzanne Korosec

Gordon Schremp

ALSO PRESENT

Dileep Sirur
Baker & O'Brien, Incorporated

Bob Poole
Western States Petroleum Association (WSPA)

Evelyn Kahl
Alcantar & Kahl LLP

Rock Zierman
California Independent Petroleum Association
(CIPA)

Dominic D. Ferrari
Plains All American Pipeline, LP

Seth K. Jacobson
Center for Advanced Studies on Terrorism (CAST)

Duane Yantorno (via telephone)
Arizona Department of Weights & Measures (AZ DWM)

Steven Sokolsky
CALSTART

I N D E X

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P R O C E E D I N G S

8:32 a.m.

MS. KOROSEC: Good morning, everyone. Welcome to day two of this Joint Transportation and IEPR Committee Workshop on transportation infrastructure issues.

Happy Tax Day. I hope everybody got their taxes done and in on time.

For those of you who weren't here yesterday I'll just do some quick housekeeping items. Restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs under the white awning. And if there is an emergency and we need to evacuate the building please follow the staff out the door to the park kitty-corner to the building and wait there for the all-clear signal.

With that, and since we have such a full agenda today and need to be done by noon, I'll turn it over to the Commissioners for opening comments.

PRESIDING MEMBER BYRON: Weren't we here yesterday, Commissioner?

VICE CHAIRMAN BOYD: I slept in my office, I don't know.

PRESIDING MEMBER BYRON: Thank you all for returning for a second day on the transportation fuel infrastructure issues for the IEPR Committee and the Transportation Committees of the Energy Commission.

We are very interested in this topic at the Commission. It was a jam-packed agenda yesterday. We assume it will be no less today. I see a couple of new faces here that weren't here yesterday. The fact is that there was a lot of information covered. We did not have enough time on the calendar so we asked our staff to make it fit a day and a half. We apologize for the 8:30 start but that's so we can finish by noon, I believe.

I am really not going to add anything else. I would like to get through it and make sure we have plenty of time for comments, questions and public comment, if necessary, at the end. Commissioner Boyd?

VICE CHAIRMAN BOYD: Ditto. I appreciate everybody being here. It's a somewhat different crowd. A little thinner crowd, maybe some are still doing their taxes, I don't know. But it's a somewhat different subject.

Yesterday was very interesting. Although this subject has proven to be very interesting, if not every year every other year. And some issues persist in remaining issues and unfortunately a host of new issues were introduced yesterday. So I think this will prove to be very productive both for the IEPR and for the ongoing work of the Commission through its Transportation Committee and the IEPR Committee.

So like you, let's get on with the show.

PRESIDING MEMBER BYRON: Okay. Let me do one more thing.

With us also is Commissioner Boyd's advisor, Susan Brown, all the way to my left. And all the way to my right is Diana Schwyzer, the Chairman, Chairman Douglas' advisor. I believe Kristy Chew will be joining us shortly. I just received a note from her that she is in traffic.

And for those of you that don't have your taxes filed today I understand that the West Sacramento Post Office will be open until midnight tonight. Gordon.

MR. SCHREMP: Welcome Commissioners, advisors, members of the public and industry. Thank you for all appearing today. And we thank

all the people who have agreed to speak today. We know we, I think, made some requests rather recently and so we are very appreciative of all the hard that people have to go through not only to be here but to cobble together a lot of information to bring to our attention.

So once again to echo the Commissioner's comments. This is to provide information as part of our Integrated Energy Policy Report process so it is a great opportunity for you folks to raise and identify those key issues that we need to be paying attention to as part of this process. This is an information-gathering proceeding.

I will be providing some information this morning on our preliminary crude oil import forecast for California. Other speakers to follow me will have some more detailed assessments of that and other issues associated with that. And I will also talking a little bit later this morning about our pipeline export and how we forecast those exports and why that is important with regard to total load on our system. So I'll proceed here.

Every two years we also do a crude oil import forecast. We're adjusting the sound here

so everyone can hear me. There we go. Before I forget --

(Feedback was heard.)

MR. SCHREMP: There we go. All right, can you hear me now? Actually is this still working? Okay.

Before I go on I just wanted to mention, when we do have our speakers, in case I forget, we are on a very tight schedule. We would appreciate if you could work through your presentation within 10 to 15 minutes so we still allow time for comments and questions. To help you with that process we will be giving you a signal that you have about five more minutes. So I'll be sitting fairly close to you so you'll see me if I have to do that. That helps us make sure everyone will have an equal opportunity to make comments today. So I just wanted to interrupt my presentation to tell you that.

So crude oil production. Crude oil production in the United States and in California has been declining. It has been going on since the peak in California in 1985 and the United States in 1986. So the decline is also occurring in Alaska. It peaked a little bit later but the

decline rate has been ever steeper in Alaska.

So here are the numbers and I'll go down into California. A similar shape. There was an up-tick in the mid-1990s as a consequence of increased activity offshore in federal waters but those fields have peaked. The decline was somewhat rapid and has leveled off. State offshore has been declining very gradually and state onshore at a greater clip but it's still a downward forecast.

So those are the trends and that's what we look at to determine what the future might hold for us.

This is a little bit longer view on California crude oil production. Back into the mid-1800s. Actually the data goes back to I think 1850. We have produced an awful lot of crude oil. But if you put that in the context of global demand it is not even a full year's after producing crude for in excess of 100 years in California, and one of the largest crude oil producers certainly in the United States. So a significant amount of oil but still rather small in comparison to global demand.

Here are just some of the facts and

figures. I won't, I won't labor on them except to point out that the crude oil production decline in Alaska has been the greatest at 63 percent since 1986. And California was the second-largest at 41 percent followed by the rest of the United States, absent California and Alaska numbers.

So we think these declines will continue. The decline rate we are most concerned about is the one in California because that affects the load on our crude oil import infrastructure.

This is a look at the receipts of crude oil, both from Alaska and foreign. Those are water-borne receipts. To us there is no difference in terms of the load on the system. They both have to arrive via ship.

So we see that there was a slight, I guess a leveling off since 2005. In part that is because of a decline in demand for both diesel, gasoline and jet fuel in the southwest region. And lower refinery runs and higher maintenance on crude oil facilities. So we are, so we are not surprised to see that the total load of imports has sort of leveled off.

But you also notice that there is a

tremendous increase in foreign imports. And this is a consequence both of Alaska's continued decline. Sourcing more -- Less and less Alaska crude oil coming to California. And the refineries understand that trend and are looking at trying different types of foreign crude oils that may work and may yield a similar slate of products. And so that's what has been going on.

And when they discover new sources that they can lock into longer term rates they will do that and they will start bringing it in and replacing that Alaska crude oil which is going away anyway. So there is no surprise in seeing the increase in foreign imports. But the difference is there is still a load on the system and that's the concern moving forward.

So as I mentioned Alaska is down quite a bit and foreign is up. We are expecting that foreign imports will continue to rise in California but we are expecting the total amount of imports to rise.

So what do we look at? We look at two factors. One is, what is the decline rat in the California fields. So whatever less crude oil is produced would have to be brought in over the

water.

Number two is, are the refineries processing greater quantities of crude oil over time in their crude oil distillation unit? So that's, we call that capacity. And over time we have seen that gradually rise. Both the capacity.

And then the final component is, what is the utilization rate? Are they running at 100 percent all the time? Of course they are not because they are performing routine maintenance every year. And larger maintenance on crude units at greater intervals and we see unplanned outages that do occur. So their utilization rates will never be at 100 percent, they will be at some lower figure. And I'll talk about that right now.

Utilization rates since 1990 through 2008 has been just a little bit under 90 percent. In recent years you see a dropping down to even below 86 percent. And so this is, you know, lower than historical numbers but I am not surprised because of the great amount of crude oil unit maintenance that was going on in 2007, and a downturn in demand that resulted in some refineries running at lower rates than they would have otherwise.

So this is not a surprise but we have to make an assumption moving forward on what the utilization rates are.

VICE CHAIRMAN BOYD: Gordon?

MR. SCHREMP: Yes.

VICE CHAIRMAN BOYD: How long can, in your opinion, can the California refineries be sustained at that low utilization rate before something happens? Something topples the least efficient refinery or something falls off the slate. The table I should say, slate has another connotation in the oil world.

MR. SCHREMP: A good question, Commissioner. The most important factor not on the screen is what are their, what are their margins and ultimately what are their profit levels that are occurring. And that is contingent upon what the market-clearing prices may be at the wholesale level for the products they are selling. All the, all the clean fuels as well as residual fuel oil, things like that, and what their costs are.

So we look at refining margins, both in, you know, different parts of the world, the United States and in California. In California, on

average, the refining margins are better than that in the United States, which are higher than that most places in the world. So it is still a very good location for profitability in terms of refinery operations.

So even though their crude rates may be lower and some of the refineries that may not have supply obligations, contractual obligations for almost everything they produce. That are some refineries that operate more on a merchant manner. They'll sell under the unbranded market and they'll have contractual obligations.

Well, we have seen refineries like that scale back their crude runs to sort of more balance out supply and demand and less imports. And then the market comes back into equilibrium, usually at a little bit higher market clearing price than it has been when it was oversupplied.

So the long-winded answer is, you can run at lower utilization rates, assuming that you are still maintaining some degree of refinery profitability, especially greater than that of some other regions.

But I don't know -- I know there was some discussion yesterday about on average in the

United States the utilization rate being at 76 percent in the long-term by EIA, which is below the bottom of this, the axis on this graph, for all of the refiners. That's rather low. And I would agree that in that context some of the higher cost producing refineries will go out of business if that's the case.

Not only that, we are seeing a large increase in refining capacity in the world. India's refinery, Reliance, doubled in size. Now they are at 600,000 barrels a day on the marketplace in May of this year. There's probably another 2.5 million barrels of refining capacity coming online over the next couple of years. This will be a lot of product on the market which will, you know, be an additional amount of competition and affect market clearing prices so we'll see how this plays out.

But running at lower rates doesn't mean you are not going to be profitable, there are other factors involved. So they can run at lower utilization rates. As you are aware, we do have a refinery that is not operating right now. Flying J filed Chapter 11 on December 22 of last year and their Bakersfield facility is not operating at

this time. So we have already seen a decrease in overall refining capacity in California as a consequence of that action but we anticipate that being temporary in nature as part of the business cycle.

VICE CHAIRMAN BOYD: Thank you. That was a very thorough answer but you did open another door that I won't pursue very far. You kind of gave some people food for thought with regard to why California prices at the pump tend to be seemingly a little higher than perhaps logic would dictate it would be as compared to prices elsewhere. So in any event, I'll let that lie for now.

MR. SCHREMP: Okay. So looking at two different decline rates. Sort of a low decline rate, which is the upper dotted yellow line of 2.2 percent per year. And that's the most recent 2006 through 2008 decline rate per annum average. Over a longer period of time, going back to 1998, we see a bit steeper decline rate of 3.2 percent per year.

No surprise that more recently the decline rate has been lessening a bit. There has been some up-tick in drilling activity. There is

certainly a great deal of drilling activity, especially when crude oil prices were in excess of $100 last year but that has tumbled down.

The decline rate still continues even with a very, you know, a very high level of crude oil prices and increased drilling activity, which is the nature of older, mature crude oil fields. Even with an extensive amount of enhanced oil recovery through injection of steam, carbon dioxide and water and steam flooding.

So we look at the decline rates and then we look at what is the utilization rate and the refinery creep. So combining those two together the lower line is the continued decline of California-sourced crude. The upper line is the refinery input, the actual input.

So we are assuming that utilization rates will be at 90 percent over the forecast period and we are assuming in this projection the low forecast rate of 2.2 percent for the crude oil production. So that yields increases in incremental imports of crude oil over the water between, you know, -- what do we have, 78 million barrels ten years out from now and approximately 147 million 20 years out. And most of that,

between 60 and 70 percent, is due primarily to the decline in crude oil rates, not the refinery expansion.

Change the assumptions I change my answer. A steeper decline rate on production of 3.2 percent and a more, I guess a more aggressive refinery creep of almost .9 percent a year. The previous slide was about half a percent per year. And so we see that the imports do expand significantly. And I'll go to --

VICE CHAIRMAN BOYD: Gordon?

MR. SCHREMP: Yes.

VICE CHAIRMAN BOYD: Sorry to interrupt you again. But harking back to yesterday's discussion of the status of import facilities, marine terminals, et cetera, et cetera. Are we presently equipped to handle that amount of import?

MR. SCHREMP: At this time -- well, time is all relative. In the near- to mid-term the answer to that is, no. Assuming no additional capacity is constructed.

There will be somebody here from Plains All American that will be discussing their project. They have been before you one, two,

three IEPR cycles. And they will talk about --

VICE CHAIRMAN BOYD: Yes, I'm aging as that project ages.

MR. SCHREMP: So we have -- Staff has assumed that if in fact that project in Southern California is constructed the additional load we are anticipating for Southern California will be met by the construction of that facility for crude oil, so that won't be a problem.

Northern California, we will be examining that in this IEPR cycle and be providing some analysis. We have not yet completed that work. But the need is growing a bit more gradually in Northern California and there are some other resupply options that may include barrels imported through Southern California and piped all the way up to Northern California.

VICE CHAIRMAN BOYD: Thank you.

MR. SCHREMP: So we'll be getting to that.

VICE CHAIRMAN BOYD: Mr. IEPR Chairman, there's a subject for the IEPR.

PRESIDING MEMBER BYRON: Gordon, another quick question if I may. These two forecasts for both the low and the high obviously show a decline

in California production. But yet we have heard recent reports and had briefings on shale gas. Is there any of that in California? Will fracturing technology and lateral drilling affect, potentially affect production here in California?

MR. SCHREMP: That's primarily with natural gas.

PRESIDING MEMBER BYRON: I'm so sorry.

MR. SCHREMP: No, no.

PRESIDING MEMBER BYRON: You're absolutely right.

MR. SCHREMP: But your question is spot on in terms of, are there some additional technology or resource potential that could affect these forecast trend lines? Yes. And that has to do with, I believe some of the speakers will address this. Is, are there some resources near shore? Offshore resources that can be got at through, say, directional drilling from onshore and expansion of offshore drilling, which certainly has been controversial.

So the answer is yes, these decline rates can not only be halted but can in fact be reversed. But it has to do with access to resources, timing of that work and the economics

of trying to develop those resources. But it takes an awful long period of time. We have estimated between seven to ten years once that whole process starts.

The lease process, just developing that lease. Putting it out for bid and then developing the work is an extremely long process. So even if in fact one were to pursue that in California it wouldn't be something that would occur next year or even five years from now. So it would take a great deal of time to come to -- But I think people are going to address some of that, some of those issues after I do.

PRESIDING MEMBER BYRON: All right, thank you.

MR. SCHREMP: Those are just the numbers we used so you have that in your presentation. I'll just jump right to the slide. These are the incremental barrels. And you 405 million barrels was the 2008 import level for the year. So you can compare those to the 405 and you see that there is anywhere from a 19 to 36 percent by 2018 and 31 to 58 percent by 2028.

So we still expect Southern California to receive the lion's share of these imports, at

least 60 percent. And I believe Dileep Sirur will be addressing that issue after, after I'm done speaking. So I just want to point out once again, reiterate that the majority of these incremental imports are primarily because of a declining, a continued declining rate of production in California, 60 to 70 percent of those barrels.

So here are some of the issues that we would like to get answers to as part of this information-gathering process that we believe we have to address at a minimum.

You know, what technology, what resources may change those assumptions on the decline rates? What other regulations may impact operations both in the crude oil producing facilities -- fields because they use an awful lot of energy, hence oil recovery.

And how might refineries be impacted? We are assuming continued growth in distillation capacity. Are there regulations such as AB 32 that could affect those operations. Are there economic reasons that may cause refineries not to continue expanding like that. So we would like input on all of this as part of these proceedings.

Here are the speakers who will follow me

in this first session on crude oil infrastructure. If there aren't any additional questions I'd be happy to have Dileep Sirur step up. Thank you.

MR. SIRUR: Good morning, Commissioners, advisors, members of the audience. I was here a couple of years ago, two years ago, to talk about -- I'm sorry, I'm Dileep Sirur, I'm with Baker and O'Brien, a consulting firm in Dallas. And I'm here on behalf of Plains All American Pipeline.

PRESIDING MEMBER BYRON: Welcome.

MR. SIRUR: Thank you.

I was here a couple of years ago to talk about the outlook for Southern California with respect to its crude supply. And given all the changes that we have seen in the environment, the most recent changes, Gordon invited us to come by and present an update of what we had presented two years ago. And there are some significant changes which we will go through. But there are other items which haven't changed; we'll talk about that as well.

Well since our last assessment, as you will see, in the last year we have had the real estate crisis and the world financial crisis. A deep recession here and all over the world.

And a steep decline in demand for petroleum products in the US.

And a slight reduction in refinery runs, but significant reduction in imported products.

And specifically with respect to Southern California, we had forecast a substantial increase over the 2006 run for 2008 when we were here last time from levels of about 2005 -- I'm sorry, 500,000 barrels a day to about 625,000 barrels a day. But the imports actually fell in 2007 and 2008. They went back to the 2006 levels so we are back where we started.

And the other things are federal legislation, which I really won't go through in great detail because I think it was talked about at length yesterday. It's the EISA act of 2007. And I think all of you know what the issues are on that.

And of course in California itself it's the Amended CARB 3 model, which was talked about at length yesterday. Where you would see an increase of ethanol content going up to ten percent.

And then the bill AB 32 with respect to greenhouse gas emissions.

And then one other one I saw there was the greenhouse gas cap and trade. The Western Climate Initiative which comprised California, four other western states and two western Canadian provinces. It coordinates with AB 32. Its objective being to keep reduced greenhouse gas emissions to 15 percent below 2005 levels by the year 2020.

All of these, clearly as enacted, would put a damper on the amount of petroleum-based refined products that would be acquired.

Now I want to go through the key assumptions that we used for going through our analysis and I'll show you the results after that. I'll start with the crude oil. ANS crude oil, 2008 product was 700,000 barrels a day. But we had predicted that -- two years ago we had predicted that to be about 750,000 barrels a day. So the last projection that we have gotten from the state of Alaska, really the numbers are well below what was projected.

And the most recent projection gives you about 2.1 percent a year reduction through 2023. We have taken a 15 year span. And again like I said, it came from the state of Alaska. In a

previous assessment the rate was faster, about 2.5 percent or thereabouts. But it really didn't have much of an effect because we are starting now from a lower number. So we already declined some it doesn't have much of an effect on an overall answer.

Now the way we distributed the ANS was identical to what we had done two years ago. We first applied it to Alaska refineries and Pacific Northwest refineries. Recognizing that those regions needed these crudes for a variety of reasons. Most of Alaska's crude is run in inland refineries. They have no alternative. And the Puget Sound refineries don't have access to many imports because of the port restrictions.

And Hawaii used to get about 100,000 barrels a day. We don't see anything going there in the future. It's not going there now.

VICE CHAIRMAN BOYD: Could I ask you a question about the decline in ANS crude.

MR. SIRUR: Yes sir.

VICE CHAIRMAN BOYD: Everybody has known that was inevitable, it was going to occur over time. I'm just wondering if the current figures documenting the declining production take into

account any technological efforts to increase yield? We're pretty ingenious technologists and over time find new ways of squeezing more through technology out of wells. Is that going on in Alaska?

MR. SIRUR: While I haven't studied this in detail the forecast, as I saw the forecast as I put this together, they have incorporated these improved technologies going to -- and then recovering some of the heavier crudes which were, which were considered impossible to recover some years ago. And they have put certain probabilities which we incorporated in there. So yes, I think the answer to your question is yes, that's been incorporated in the forecast as well.

VICE CHAIRMAN BOYD: Thank you.

MR. SIRUR: Now the balance of the crude then goes to California. And the way we have divided between Northern and Southern California, we have given more to Northern California, recognizing that Southern California is already kind of moving away from ANS much faster than Northern California is.

Now with respect to California crude. Two years ago we said it would decline at 3.5

percent a year and that we have not changed. And our rationale is relatively simple. For the last five years it's declined at the rate of about 3.3 percent a year in a generally rising price environment. So given that we felt that there was not much justification for changing from the 3.5 percent level that we had before.

And the way we distributed the crude was first send it to Bakersfield and Santa Maria area refineries, which do not have access to foreign crudes. And then we also assumed, this is another point, the Flying J refinery which we just talked about, or some proxy, which meant that some other refinery would pick up this capacity if you will. Not one other refinery but several of the other refineries would take this capacity on an incremental. We assumed that would restart by the end of next year or by 2010.

VICE CHAIRMAN BOYD: So the assumption is none of that oil will be stranded in the area.

MR. SIRUR: That's right.

And then again we move the oil to Northern and Southern California. And recognizing the marine logistics in Southern California we preferentially move the crude to the north and

then the balance went to the south.

Now this is where we made some significant changes in refinery runs. In our last assessment we had assumed a 1.25 percent increase in refinery runs, or a creep if you will, for the 15 years that we had there. And in addition to that we assumed that one of the refiners would add 50,000 barrels a day of capacity in 2012.

And I think it's pretty clear to us now that these assumptions are really not likely to be realistic in the current market and economic environment that we are in. So rather than try to predict something where things are so fluid we decided to look at three alternative scenarios for the next 15 years, which is from 2009 to 2023.

The first thing we did, we eliminated that extra 50,000 barrels a day capacity. We just I think felt that in this environment or into the foreseeable short-term future you are not going to see additions of capacity.

And then we hanged the refinery run increases. And we looked at three scenarios. The first scenario, we said for all 15 years it would increase at one percent a year. We called that Scenario A.

And then Scenario B, we went to one percent a year for the first five years, half a percent a year for the next five years, and no increase for the last five years. Kind of recognizing that some of these rulings that we talked about would start phasing in around those periods. Around the latter part of this time horizon.

And then the third one, which is just a variation I believe, of B, was that we kept the one percent a year for the first half and reduced it to zero for the second half.

Now on the next slide here I have a -- I'm sorry, I need to talk about crude oil imports, how we managed the crude oil imports analysis.

Right now the imports are coming from the Middle East, Latin America, West Africa and some amounts are coming from the Pacific Rim and Canada.

And what we did was we maintained the current levels of imports and just escalated them for the refinery run increases to keep, to kind of maintain the current levels and not change them.

But then the increasing reductions in ANS and California crudes made up additional

imports.

ANS was generally substituted for with similar quality, they typically tend to be somewhat higher in sulphur Middle East crudes.

California, we replaced them with a combination of heavier crude oils which were from Latin America, West Africa and some from the Middle East.

And then just a note here. The incremental Canadian crudes, which are really the oil sands bitumen crudes that are being produced now. We expect to see -- we said we would expect to see some by 2016 pipelined from a deepwater port in Northern British Columbia.

Now there's a lot of controversy out there. I think things have slowed down in Canada because of today's prices. The availability of this crude, because it needs a pipeline, is, you know, is kind of questionable. But then if that weren't available some other crude like Nigerian crude or Latin American crudes would be required.

And finally, West African crudes would also increase. And these would be low-sulphur, heavy crudes. And the word, I think, high TAN, is just very acidic crudes which don't have an easy

market but could do well as a substitute for California crudes, which also have the high TAN.

I'll go through this real quickly but this is -- if you looked at Scenario A we have history through 2008 and then the future to 2023. We have orange is imports and green is ANS and blue is California. This is for the Scenario A. And the runs go up to about 1.1 million barrels a day and the imports are around 1 million barrels a day.

I've got a few more slides later that will show the imports more clearly so I'll just show you the next two very quickly for Scenario B, which gives you a slightly lower 2023 run rate and corresponding lower import rate.

VICE CHAIRMAN BOYD: Could I ask a question. Do your projections for the future take into account any estimate of the penetration of alternative fuels into the --

MR. SIRUR: In a way they do. We are believing I think if it wasn't for the alternative fuels we wouldn't have gone up this slowly. Particularly towards the latter part we are flattening out our refinery runs. That I think is recognition of alternative fuels, clearly.

Now this I think is more, I think I want to spend a little time on these three charts. The first one shows, the first bar is for what we have in 2008; the next bars are for 2013 for Scenario A, B and C. These are identical for 2013 because all of them are for the -- all three of them have one percent a year through 2013.

But as you go later in the period. When you go to 2018 the increase becomes much better defined. And you can see there the differences between Scenario A, which is among the three more aggressive, and Scenario C is the least aggressive or more conservative. But one of the things you see here is that imports continue to be dominated by the Middle East and Latin American, that does not change.

And then we go to 2023 for the same slide. And again you see Scenario A is having about a million barrels a day imports and Scenario B and C having a little over 900,000, 950,000 barrels a day of imports. Compared to about 500,000 barrels a day in 2008. And you still see domination by the Middle East and Latin America.

This next slide is -- it looks like the same as the others and it isn't. I was talking

about a 2007 assessment. So this is for the year 2023. The first column is what we -- our assessment in 2007 which I presented to you two years ago. And I compared that for the same year with Scenario A, B and C. And you will see that there is about a 200,000 barrel a day import difference between the 2007 assessment and Scenario A. And another 50,000 or so more for Scenarios B and C.

So that's where you see the key difference with all the input changes that we made. In the last year where we were -- in the last two years where we assumed a zero growth of refinery rates. That's where you see the very, distinctly see the difference.

But one thing. With all the, with all the different scenarios that we have looked at it's pretty clear. The reason why we still have a significant need for imports is because of the decline of California and ANS crudes. Which really the perception of those declines hasn't changed.

I'll go through this pretty quickly. This is just what we observed from what I have shown you in the bar charts. And these

conclusions have been dampened but haven't been changed since the, since my 2007 presentation.

I think by the end of this forecast period the Southern California supply will be dominated by imports.

Imports, depending on which scenario we have, will be between 900,000 to a million barrels a day, which is roughly 80 to 90 percent of total crude oil runs.

And this is compared to half a million barrels a day, which is 50 percent of total crude oil runs.

The Middle East will be the primary source. About half a million barrels a day or 50 percent of crude oil runs.

And the import of Canadian crudes will increase to about 70,000 to 80,000 barrels a day starting in 2015. Earlier we had said it would start in about 2012 or so but I don't think that's in the cards.

West African crude will continue to increase to levels of about 130,000 barrels a day.

Latin American crude imports, again, from today's 200,000 barrels a day will increase to about 260,000 barrels a day or so.

And Pacific Rim has been very minimal and that will, that will stay that way.

VICE CHAIRMAN BOYD: I can barely discern the red line on your chart.

MR. SIRUR: That's right. I think we should have had a, I think we may have missed some of the red lines. Because I saw one but --

ADVISOR BROWN: I have a question.

MR. SIRUR: Yes.

ADVISOR BROWN: Excuse me. Just on the first bullet. I'm assuming that you mean oil sands when you estimate Canadian oil imports.

MR. SIRUR: That's right. When I said "new" I meant oil sands, yes.

VICE CHAIRMAN BOYD: Can I ask you. Latin American imports. Do you have that dis-aggregated in any way to various source points?

MR. SIRUR: Historically we do. And we are looking at -- at this point, I mean, if we look at what is happening today. There is a considerable amount of oil coming from Ecuador. There are two grades there. One is called Napo -- One is called Oriente, which is somewhat lighter but it is still quite heavy. And then they have got a new grade called Napo which is 20 API and

relatively low in sulphur. It's about two percent sulfur.

Those are the two crudes that have dominated recently along with Mexican Maya crude, which is 20 API and quite high in sulphur, 3.5 percent. But just a few months ago the Mexicans have been, their production has been going down rapidly. They stopped shipping to the, they stopped shipping to the West Coast. And even the, even the Gulf Coast refineries are having problems with getting their allocations.

Another crude that is starting to show up in considerable volumes is a Brazilian heavy crude. Marlim (phonetic) is the name of that crude. And that's about one percent and 19 API. And it's highly, it's quite acidic so it would fit very well and does fit very well in, on the West Coast. Chevron I believe has been bringing considerable amounts of that into that their refinery.

VICE CHAIRMAN BOYD: Thank you.

MR. SIRUR: So that concludes, concludes my presentation and I'll be happy to answer any more questions.

VICE CHAIRMAN BOYD: I have no

questions, maybe a statement. The last bullet on your next to the last slide about the Middle East being the primary source of total crude imports. And that's pretty well dominated many of your projections.

MR. SIRUR: Right.

VICE CHAIRMAN BOYD: I would, I would just say I guess that that's a problem for this country and that's a challenge that we have to deal with. It's an economic problem and an economic challenge.

MR. SIRUR: And I think the real problem, there is, there is so much of it there.

VICE CHAIRMAN BOYD: Right.

MR. SIRUR: The production is dominated by Middle Eastern crude. And even -- Of course the ANS, ANS now is a 30 API, one percent sulphur crude. And if you look around there are very few animals that look like that. So you just about have to bring in some relatively light Middle Eastern crudes which have higher sulphur so that you don't disrupt the operation of the refinery but you have to make arrangements to remove the sulphur from it.

If you look at Chevron's imports, for

example. Chevron used to run a lot of ANS. Which if you look at the total, if you just estimated total runs and then see how imports they are bringing right now you could see that their ANS has been going down dramatically. At one point I think they virtually ran all ANS and now they are running less than -- significantly less, let's put it that way. But they have put in a lot of sulphur recovery equipment to do that.

VICE CHAIRMAN BOYD: Thank you.

PRESIDING MEMBER BYRON: Thank you very much.

MR. SIRUR: Thank you.

MR. SCHREMP: Thank you, Dileep.

We have Bob Poole who is here from WSPA. He is going to provide us with some additional information. One of the questions you had was potentially other resources that may be available that could affect the decline rate assumptions. He'll be talking about that. And then I guess Evelyn Kahl will be on deck.

MR. POOLE: Good morning, Commissioners, advisors. Thank you for this opportunity. As Gordon said my name is Bob Poole. I am a senior coordinator for Western States Petroleum

Association. And I know my boss, Joe Sparano, spoke to you yesterday and is a regular commentator here.

One of the things I deal with are the offshore issues, the regulations relative to the platforms. A lot of the coastal issues, production upstream, and also marine issues. So I'm here to talk a little bit about in terms of addressing the energy adequacy issues in terms of transportation fuels. Talk a little bit about access infrastructure and the current existing technology and opportunities that we have in the offshore environment here.

Now in terms of -- Commissioner Boyd, you mentioned about the Middle East crude being a problem. I would suggest here that we do have reserves offshore, our own country. And that -- or the main challenges for us to bring forward is access to those resources.

VICE CHAIRMAN BOYD: My, did I give you an opening.

MR. POOLE: Yes you did, sir. I hope you don't mind I used it.

VICE CHAIRMAN BOYD: I would expect so.

MR. POOLE: Yesterday my boss spoke in

terms of that the future will require multiple sources and strategies. Along those lines my talk is going to key in on domestic supplies through greater access, obviously. It is also going to talk about the existing infrastructure, both offshore and onshore related to offshore that supports that. The current state of the technology that's being deployed and that can be used to enhance the recovery of the existing resources. And then I'll finish with just a little brief underscore on AB 32 implementation.

Now here is a little more drilled down, if you'll pardon the pun, look at the resources off of California. As most of you know most of them are off the coast of Santa Barbara County, both on the Santa Maria Basin up by Point Sal and then down below in the Santa Barbara Channel. There are also some other areas of production and what I would like to do is go through and show you those here briefly.

But first I would like you to know that there are 23 platforms offshore in federal waters, that's beyond three miles, and there are four platforms operating within the three mile limit, three of which are off the LA Basin, I'll show you

a map on that, and one off of the coast of Santa Barbara, Platform Holly.

Here are three different maps form the Minerals Management Service that gives you a little better understanding of the infrastructure. The platforms that are offshore, the various pipelines that are bringing those products to shore. All the power that's, these platforms have all basically been electrified to reduce emissions so there's a lot of, there are power cables back and forth on those.

So the structure in the San Pedro Bay. You can see there are a number of platforms, both in the federal waters and in the state waters and then some onshore facilities.

The image in the middle there, Santa Barbara Channel, is where the majority of the platforms are. The Ventura Field extends offshore kind of at a diagonal and those platforms are for the most part seeded over top of that offshore reserve of the Ventura Field.

And then going up around the corner in the Santa Maria Basin. You can see there are a number of platforms. The highest platform is Platform Irene, which is our northernmost

platform. And that's just off Vandenberg Air Force Base.

There are also five man-made islands that are being used in the production of offshore crude, four of which are contained in what is called the THUMBS area down by the Queen Mary off the City of Long Beach. There is a joint effort between the City of Long Beach and the state of California. Occidental operates that on behalf of the City of Long Beach and that's where four of them are. Here are two of those four.

And then the fifth one occurs just on the northern boundary of Ventura County. You may have seen it driving up and down the coast. Rincon Island, there's another production facility as well.

Now here is kind of a more expanded version of the operations, the infrastructure that's in place right in Santa Barbara County. If you take a look offshore, the squares there if you will, the light blue squares, the little platforms. Those are active leases, units, fields being produced. The white squares are leases that have been put forward but are for the most part currently in litigation. There are some other

opportunities there.

But if you take a look at the squares that's basically where the oil is, relating back to the previous slide that I showed you. And then you can see the platforms. You can see the little red lines, the pipelines coming onshore. There's a whole structure of pipelines carrying product, both to onshore processing facilities where a variety of things happen such as the removal of sulphur, heating up the oil to move it on beyond the platforms.

There is some refining capacity. And then transporting the oil to the other refinery centers, both in Northern and Southern California. So we have a comprehensive, very complex yet, very functioning infrastructure that relates to the production of the offshore reserves.

I'd like to talk a little bit about technology right now in terms of the support of that. What you see here is a schematic of a, I guess, finished wellhead. It also shows the sub-surface casing, et cetera.

The basic point I wanted to show you here is there's redundant system upon redundant system, including the various layers of casing and

cement going all the way down in this, in this particular instance to over 6,000 feet below the surface of the ocean, below the bottom of the ocean. On top of that you have got a variety of pressure valves, blowout prevention, shut down mechanisms. This is the technology that is in place in all the offshore platforms today.

In addition some of the applications of technology to both reduce the footprint, which I'll show you a slide on that in just a moment. I just wanted to run down through a checklist.

Measurement-while-drilling technology. There are actually computer components in the drill heads themselves that allow them as they are searching to know if they hit a high pressure area. Also to direct the drill in directional drilling, which I'll talk about in just a minute.

Global positioning systems to also give the feedback as to trying to aid in the recovery of those reserves.

High resolution inspection and monitoring devices.

Remotely operated underwater vehicles.

And what you see here is an image of 3-D seismic technology in terms of trying to find the

resources.

Now since 1970 there's been over a billion barrels produced off the coast of California.

There's been less 850 barrels accidently spilled.

There's currently 55,000 barrels a year seeping off the Santa Barbara Channel from natural seeps.

Here's a little slide that speaks back to the technology plus in terms of infrastructure. As you can see, the platform to your left is a fixed leg platform. All of the platforms off the coast of California are fixed leg platforms. However, you can also see demonstrated here a whole variety of other technologies that are being used around the world and that could possibly be available for us to consider as compared to sitting in a fixed leg platform.

In terms of footprint. This diagram is -- starting in 1970 you can see that the above-ground drill size approximately 20 acres and it would exploit an area below the surface of less than a square mile. That has been evolved now to where we have a 2 acre above-surface imprint with

an 80 square mile capability. So considerably less in terms of a footprint.

Pardon this slide but I think it illustrates the point. Directional drilling, you are probably familiar with that. It is a very involved technology. I think the record somewhere is between seven and eight miles right now to the accuracy of a cubic meter, I believe. It used to be a hall closet they referred to it but it has gotten even better.

But those all of those various technologies I was telling you before, and a lot more evolved drilling technology, we have options to be able to go after resources from existing platforms and also to have those resources extracted from shore in terms of directional drilling out to the reservoir.

Now getting back to the issue of access in terms of the status of our current policies. As I'm sure you are aware California has a moratoria on offshore drilling within the state waters.

There were two provisions within that legislation, AB 2444, that allowed for projects, two particular instances where projects could go

forward. One of them was the production of a reservoir in state waters from an existing federal platform. And you may know one of the oil companies recently had a project go through to the State Lands Commission where it was turned down. But that was a provision that was allowed within the moratoria structure of California.

There is also another exception and that would be full field development of an existing lease. There is a project currently going forward with that off of Platform Holly. So even given the California moratoria structure there are some opportunities right now that are being brought forward.

You may know tomorrow Secretary Salazar, the Secretary of the Interior, will be speaking and there will be a workshop over in San Francisco. The federal moratoria, which was lifted I believe in July of this last year, the Minerals Management Service has moved forward with their regular five-year plan. This one in the instance of the 2010-2015.

And in that plan, which will be discussed, input will be received tomorrow in San Francisco, there are options in the plan for

leases in California off the coast of Santa Barbara. This little diagram was taken out of the proposed five-year plan to show you that there are some other opportunities in that regard.

I think to recap, it's all about access. I think that some of the other, of the earlier comments reinforced this.

Eighty percent of our US energy through 2030 is going to come from fossil fuels.

Our dependence on foreign oil, as you know, is projected to increase.

Domestic resources needed to reduce imports are available.

The infrastructure and the technology exists to increase that production in environmentally safe and sensitive ways.

And WSPA thinks the prudent development of these resources is an essential component of meeting California's energy needs, now and into the future.

And I'd like a quick, just to make a quick comment about AB 32. Clearly the implementation of AB 32 is very comprehensive and very complex, especially with regard to the petroleum industry. And from the upstream side I

just wanted to touch on a couple of issues today briefly.

And then we would appreciate the opportunity to further discuss some of our concerns related to the implementation of AB 32 and how it could potentially affect the infrastructure and the adequacy of our fuel supply. But WSPA has been engaged for quite some time, and will continue to be, with the AB 32 issues and implementation to try to make sure we get it right, there's a lot at stake.

And a couple of the issues that we are working on the upstream side. In terms of the scoping plan, to try to establish the emissions inventory on the production facilities. We have been working very closely with CARB staff on that, we continue to do that.

And then one of the other issues of concern is where you have a -- in terms of energy efficiency we have a co-benefit. You may be reducing criteria pollutants at the same time you may be reducing greenhouse gas. And so in terms of making sure we get that right so that we get the co-benefit, I guess, is just a simple way to say that.

I think that concludes my presentation. I'd be glad to answer any questions if I'm able.

ADVISOR BROWN: Can you expound upon the federal moratorium lifting and what that means for offshore production.

MR. POOLE: Well if you go back to the slide where the resources are. I think, you know, I would start with a response that if the moratoria is lifted then potentially the processes that are in place now, in particular with the Minerals Management Service, and if it stays lifted. It is obviously lifted. Would allow more opportunities for exploration of these reserves offshore.

There's a couple of items in the plan now. So if they were to move forward, the moratoria would stay lifted, then there would be the opportunity for companies to bid on those leases and move forward with trying to extract those resources. Did that?

ADVISOR BROWN: Yes, I think that's good. Obviously this is still in play with the workshop tomorrow in San Francisco and the policy of the new administration could well change; isn't that true?

MR. POOLE: Well yes. And my understanding is this is a proposal. And part of the reason for the workshops and the input which you can give up until September is for the Department of the Interior to decide what that, what that leasing plan ultimately will look like. It has a completely new component in it this year in terms of alternatively energy, in terms of wave and wind in particular in the offshore environment. So there's a whole other dimension to it. But until the, until the comments or in then it may or may not remain in the plan.

ADVISOR BROWN: Thank you.

MR. POOLE: You're welcome.

PRESIDING MEMBER BYRON: Thank you for being here. The directional drilling that you talked about that could be implemented on existing platforms. Is that underway yet at all at this point? How much additional opportunity would that present?

MR. POOLE: Yes, it is being used in most or all of the platforms, I would assume. I know that in particular it has allowed a couple of operators to get at resources closer to shore from platforms that are further out in the channel in

particular.

Directional drilling is contemplated in the two projects that are provided for in the provisions of the California moratoria. That's how those resources would be accessed. There's another project currently moving forward in Carpinteria, California, where there would be directional drilling from shore out into a reserve.

So I think it clearly is central to the issue. Both currently it is being used across the board with extraction and it would play very significantly in the future. Did that answer your question?

PRESIDING MEMBER BYRON: Yes, thank you.

MR. POOLE: Okay.

ADVISOR BROWN: Could I ask one other question? What ever happened to the Point Arguello field off the coast of Santa Barbara that Chevron was once planning to access. Can you just update us on that.

MR. POOLE: My understanding, it is still being produced currently by another company; there are three platforms off the coast that are doing that. However I think that the resources in

that particular field if I recall, and I'm trying to recall this from memory, they weren't as large as what Chevron had thought at the time.

ADVISOR BROWN: Right.

MR. POOLE: And that that onshore --

ADVISOR BROWN: And the quality was poor.

MR. POOLE: What's that?

ADVISOR BROWN: The crude quality was poor too, as I recall.

MR. POOLE: Right. Thank you very much.

PRESIDING MEMBER BYRON: Thank you.

VICE CHAIRMAN BOYD: Thank you.

MR. SCHREMP: I have a couple of quick questions for Bob. To expand on what Commissioner Byron started asking about. What resource may be potentially available. Of the 10.5 billion barrels is really any of that resource available through directional drilling from either onshore or any of the existing platforms in state or federal waters?

MR. POOLE: In the short answer, yes. I think in terms of a function of the ability of directional drilling to go out seven to eight miles first off. And that there are platforms

existing clearly out 12 miles. So from that range you can see that they have a range roughly of about 20 miles. As far as lease-specific. We could go back to the slide that shows the fields and kind of get a little better sense of that. But I think the short answer is clearly yes.

Is that it? Okay. Is that it?

MR. SCHREMP: Thank you.

MR. POOLE: You're welcome.

MR. SCHREMP: And Susan, I think there has been some estimates by I think the Energy Information Administration on how much additional resource and when could become available if the moratoria was lifted in all federal waters in the United States. So we can also provide some of that information as part of this process for you.

ADVISOR BROWN: And I also assume that we will be closely following the MMS process for opening up those leases and whatever developments occur.

MR. SCHREMP: That's correct.

Thank you, Bob.

And Evelyn Kahl is next.

MS. KAHL: Good morning, Commissioners and advisors. I'm Evelyn Kahl and I'm from

Alcantar & Kahl, here on behalf of WSPA today. And I have been asked to address two relatively unrelated issues that affect oil production and oil refining in California.

And the first one is combined heat and power. And it's a delight to be here and talk about combined heat and power in the context of industry infrastructure rather than simply the electricity sector.

And the second issue I'll talk about is a few pipeline access barriers in Southern California to associated gas. And as you know, associated gas can't be produced and restricted, crude oil is restricted.

I think we all know in this room that CHP has been identified by the ARB as a key measure in meeting AB 32 goals within the electricity sector.

And today we have CHP operating in the state that has been operating for a couple of decades. And it is estimated that that CHP saves between 8 and 20 million metric tons annual. and ARB is looking to increase those savings by an additional 6.7 million metric tons a year. So it's a key element of the scoping plan for

electricity.

And what we are here to talk too about today is continuing to support policies. And I say continue because you have been the greatest champions of CHP policy in the state. To retain existing facilities, promote new development, and to make sure that our RPS policies don't get in the way of CHP.

CHP is an important element of the oil and gas infrastructure. If you look at this graph which is part of the 2005 CEC database it shows that of all of the CHP facilities in California, 45 percent of them are related to oil and gas operations, 13 percent for refining and 32 percent for EOR. So obviously it is very important to the industry and the industry is very important to the state's goals.

With respect to current facilities I'll talk a little bit about what WSPA, the WSPA companies have currently and are contemplating. Today WSPA companies have roughly 2600 to 2700 megawatts of CHP capacity in place. A large majority of it was put in place as a response to PURPA in the late '80s and the early '90s. There were a couple put in place in response to the

energy crisis in the 2002-2003 time frame.

Of all of those facilities roughly half of the electricity in aggregate is exported and the rest remains onsite.

There is additional industry potential. And I know that you will be getting into this in June when you are looking at the CHP potential in California. But within WSPA alone there are about 2,000 megawatts of thermally matched CHP potential and about 200 megawatts of electrically matched.

And there are about, that I can think of offhand there are three refinery projects that are currently on hold for CHP that are either under permitting or have interconnection requests in.

And there are two in the oil producing fields right now that are interesting. And I say interesting because in one case CHP has been foregone already for new boilers, and you may be aware of that. And in another case there was a very large CHP project under consideration in an EOR field that has now been shelved and it is no longer in among the choices being examined being examined by that company to meet their increasing thermal demand.

So those are opportunities arguably

lost. The refinery projects are still sitting out there and there are some others to be tapped as well if conditions are right.

VICE CHAIRMAN BOYD: Will be addressing that in more detail at our June hearing on the subject?

MS. KAHL: Yes, I hope to.

VICE CHAIRMAN BOYD: I'd like to hear more about it but not necessarily today.

MS. KAHL: And as you know the EOR and refinery CHP are among the most efficient in the state. They are, you know, anywhere from 60 to 80 percent on a higher heating value basis.

While California has been successful in the past in attracting CHP what this graph shows is that our policy has flatlined. If you look at the dark purple or red line on the graph that shows CHP installation by year. It is not cumulative, it is installations by year. And above that in the dotted line is capacity additions generally in California by year.

And what you can see in the middle there is the big PURPA response. And after that you can see a little bit more development. And around 1996 we start to go flat. And there was a reason

for that. But the fact remains that we have no policy to support new CHP. There is very little that is being developed today.

There are a variety of barriers that are leading to this consequence. I think there are certainly limited sales opportunities for excess power coming from these facilities. PURPA was essentially eviscerated by EPAct of 2005 by the feds. The CHP pricing under PURPA that the PUC has implemented just isn't good for bringing new megawatts, it just won't cover the cost of development. And there are no real market alternatives today.

Unknown GHG costs and no recovery assurance. So that's got to be factored into the economics and it's really an uncertainty.

Utility exit fees are added to the customer capital costs. Right now those range from anywhere from $11 to $29 a megawatt hour, which burdens your project from the outset, as you can well imagine.

Complex grid interconnection rules and AQMD restrictions.

And finally the last one, which I don't think you can see up here, it's the utility

reluctance to take baseload power.

I wanted to talk very briefly about it because it is coming up in the RPS context over at the Legislature.

The issue is whether the utilities can take any more 24/7 power. And as you know a refinery or an oil producing field needs to operate its CHP around the clock in order to meet the thermal demand. And what the utilities have been saying is we don't need your power because during minimum load conditions we have excess generation. So they are not interested in any more 24/7 power and they are looking for dispatchable power.

And this kind of highlights the problem here. If you look at the bar graph on the left it shows the 2010 conditions that have been mapped by the ISO in their average conditions. And in the stack you see all of the must-take resources that are operating during minimum load conditions.

And what you can generally see under a 20 RPS in 2010 is it's fairly well-balanced. Not during every hour but on average it is fairly well-balanced.

If you push it to 33 percent RPS, the

bar on the right. You can see the red line across the top there is the minimum load and the stack is the must-take generation during minimum load hours.

So you can see if things proceed as the ISO has predicted here we won't have room during minimum load hours for all the resources we are looking for. I don't have an answer for that but it is certainly an issue that needs to be addressed, both as we talk about new RPS resources and as we talk about CHP. What can we do with the minimum load stack until we get to a place where we have real storage opportunities.

I won't go through the next three slides with you. They are really just a reiteration of all the agency support that has been voiced for CHP over the last few years. And I have to say, while there have been a lot of kind words there still hasn't been any action. This has been going on for a decade. We can't get traction to really get a CHP policy in place.

VICE CHAIRMAN BOYD: We've noticed.

MS. KAHL: Yes. And that isn't your doing, I realize.

But what we are carrying around I guess,

both to ARB, to the CPUC and obviously here is that we need to make efforts to retain our existing generation.

Stop trying to unwind prices retroactively.

Protect against the EPAct 2005 termination.

And to get a commercially viable contract in place.

In addition we are hoping for a new California-based CHP policy. Something that is like a supply-side energy efficiency portfolio, a feed-in tariff or a PURPA-like program.

Let's talk about some prices that will really support these projects.

And let's minimize exit fees.

And as I mentioned earlier, we need to coordinate our RPS and CHP policies.

Moving on to the natural gas pipeline issue. This issue arises because as I said earlier, if you can't get natural gas to market and it's associated gas that means you are leaving oil production behind as well. And there are two very limited issues that have come up in the natural gas context in Southern California that I

wanted to share with you. They are both quality related.

There was been a long disagreement in Southern California over how quality issues should be handled for California-produced gas.

And after years of debate, very many years, we have still be unable to resolve them. One of them is how you really measure the gas quality, over what time period. And the other is how we deal with the ARB NGV standard.

And the lack of resolution of these creates uncertainty, it increases flaring in some cases and it results in lower production levels.

With respect to sampling and measuring gas quality. Historically SoCalGas used monthly composite sampling. That meant that they had a device that grabbed a sample every so often. At the end of the month they would see what the gas quality was from a particular point of interconnection.

And in recent years SoCalGas installed gas chromatographs at most of the points so they are able to measure it instantaneously.

And they have been driving the GCs as fast as they will go, which is, you know, they

measure in four-minute intervals. And if you have two four-minute intervals that are out of compliance you're shut-in. So there's an alarm that goes off --

PRESIDING MEMBER BYRON: GCs are general conditions?

MS. KAHL: Gas chromatographs.

PRESIDING MEMBER BYRON: Gas chromatographs, thank you.

MS. KAHL: And there is no materiality standard here. If your carbon dioxide limit is three percent and you are at 3.1 percent for eight minutes you are shut-in. So it's created a problem in managing the fields in a variety of ways.

And one of the ways that the companies have dealt with it is by increasing flaring. Rather than letting that gas go through the pipeline and get shut-in they will flare some of the gas off before it goes into the pipeline and out to SoCalGas to prevent that from happening.

So you have increased flaring, and in some cases reduced production, just to avoid the shut-in. Because once you are shut-in it is expensive and it is time-consuming to get back on-

line. It's not like you just flip a switch on and off and bring your production back on-line. So we have been discussing this issue with SoCalGas and the PUC for several years and it continues.

The last issue is the CARB NGV standard. And this has been going on for years and years as well. And the question is, how do we apply ARB's NGV standard, their CARB 6 standard or their methane number, with respect to pipeline access. And the PUC has said twice that the ARB standards are not pipeline standards. And yet still SoCalGas uses them as pipeline standards to prohibit access of some supplies to their system over certain pipelines.

The position they have taken is, well they don't apply the full CARB 6 standard or the methane number standard. What they are saying is, we are going to grab the six percent ethane limit out of that standard and apply it to the gas coming in from California producers.

Again it is limited flexibility for California production coming to market.

So those are all my comments and I'm happy to answer any questions you have.

VICE CHAIRMAN BOYD: I anticipate we'll

see you back here, Evelyn, for at least two different hearings, the natural gas hearing and the CHP hearing of the IEPR Committee.

PRESIDING MEMBER BYRON: Ms. Kahl, you went through a lot of material very quickly. I'd like to think I know a little bit about the CHP but I had difficulty even keeping up with you. Could you go back to Slide 9 please and take a little bit more time and explain what this slide is about.

MS. KAHL: Okay. This slide is about how the state's electricity supply looks during minimum load hours. And minimum load hours are the hours when the state's demand is lowest. And typically they occur at night, off-peak hours. So the demand is very low.

Yet when the demand is very low you have a certain number of resources that need to be operating, as you know. Your hydro in some cases, nukes. Some minimum --

PRESIDING MEMBER BYRON: So when you say must-takes you are also including in all the renewables here too.

MS. KAHL: Right, right. And renewables, it's primarily wind and geothermal I

think at this point because solar isn't on during the off-peak hours.

PRESIDING MEMBER BYRON: It doesn't operate at night yet.

MS. KAHL: So you have got a situation where your minimum load may not match your must-take resources or your minimum generation during those hours. And the question is on the stack on the right, if you get to a point where your resources that must run during the hours are in excess of your load, what do you do and what's the value of those resources at that point.

And so the point is that the utilities are using this argument to say, we don't want any more CHP because it's 24/7 in many cases. We just don't need 24/7 anymore.

PRESIDING MEMBER BYRON: Right. Of course Commissioner Boyd and I still continue to sit on a lot of siting cases where we are continuing to site a number of baseloaded natural gas-fired power plants.

MS. KAHL: Yes.

PRESIDING MEMBER BYRON: All right, thank you for taking that time.

Moving on just a little bit. With

regard to promoting new CHP generation. We did have a workshop on -- today is Wednesday.

MS. KAHL: Monday.

PRESIDING MEMBER BYRON: Monday. Were you here for that as well?

MS. KAHL: Yes I was.

PRESIDING MEMBER BYRON: And we learned a great there with regard to the AB 1613 legislation that is underway. As I recall, though, the large producers are not going to participate in 1613. Primarily for what reason? Is it resources? Is it too small of a megawatt threshold?

MS. KAHL: It is, it's a 20 megawatt and under proceeding. And as you probably know, at the oil refining and production facilities they are much larger facilities typically starting at 40, 42 megawatts. So it's not relevant for these companies. And what we are hoping is that the PUC follows through with its promise to have a rulemaking on the larger CHP facilities this summer.

PRESIDING MEMBER BYRON: All right. And of course what we are trying to do is, I believe Assembly Member Blakeslee's legislation was trying

to get a foothold, if you will, and so we are starting with 20 megawatts and below. Which is still substantial in size. But you are absolutely right, not big enough for the cogeneration opportunities at refineries. Okay. Well, this is very good. And I do hope we will continue to hear from you.

Commissioner, it just seems to me though that based upon what I have heard from this presentation, Southern California Gas and Southern California Edison just don't seem to like these folks. That's the impression I get. I mean, this has been going on for a long time.

MS. KAHL: Years and years.

VICE CHAIRMAN BOYD: Decades.

MS. KAHL: Yes, it is actually decades in some cases.

You know, and in closing too I would like to ask your help with one issue. Which is, you clearly understand the issue, you understand its importance. But we can't seem to communicate with ARB and the PUC about it. At times it's the timing question.

As I explained, we have a couple of projects that could have been built that probably

won't be built. And this is all about timing. And, you know, starting in the summer is terrific but we'll be done five years from now and all those opportunities will have passed us by with boilers.

So thank you.

PRESIDING MEMBER BYRON: Thank you.

MR. SCHREMP: Thank you, Evelyn.

We have Rock Zierman from California Independent Producers (sic) Association. And then on deck would be Dominic Ferrari.

MR. ZIERMAN: Good morning, Commissioners, advisors. Thanks for the opportunity to be with you today. Rock Zierman, California Independent Petroleum Association.

In an effort not to be repetitive I wanted to focus on specifically two questions that Gordon and staff raised in their document. Specifically, can you stem the decline in production in California? And number two, are there regulations, such as AB 32, if you are successful in doing that that would threaten that?

And the spoiler alert is the answer to both of those is yes. In fact, that's not really conjecture but what we have seen in production

numbers last year. In 2007 onshore production in California was 203 million barrels of crude. In 2008 it was 203 million barrels of crude because of the heavy drilling activity. Where we got the decline was actually offshore. So if you open up offshore access you can actually and very credibly stem that tide.

So I wanted to focus on is what sort of scenarios do you have to have in order to have that take place.

When companies are making decisions about when and where to invest I wanted to focus on some of the questions that run through their mind. Number one, this is a very expensive, very capital-intensive industry and you have to have access to that capital in order to drill.

Secondly, obviously you need a rig, a drilling rig in order to do that. Typically companies don't own their own rigs, they contract with drilling companies specifically. Offshore production and offshore platforms are the exception, typically. They have their own rigs that are permanently placed on there. We'll talk about that a little bit.

Once you have capital and a rig you also

have to get permission from local, state and federal agencies in order to drill. So we'll look at some of the biological hurdles and the biological calendar that you have to follow in order to complete your drill.

And when you're talking about minerals obviously that are on state and federal lands you have to have permission from those agencies to access those minerals.

And there are also subsets. These first four issues are global and universal and every company in every state and every country faced these four things. But there are individual dynamics in each market that are particular to that market that affect whether or not somebody drills there and we'll look at some of those as well. Obviously one of those on the horizon in California is AB 32.

Just quickly on the capital issue. Obviously it's capital-intensive. Independents are actually heavily engaged in drilling. They are almost exclusively doing the exploratory wells nationally. A study has shown that they reinvest up to 150 percent of their net revenues into new drilling.

Well how do they do that? Well they have to go out, obviously, and get equity partners or bank loans to provide that extra 50 percent in order to drill. They are constantly looking at the future and how they can continue to operate since they have obviously a resource that naturally declines.

So the credit crunch that has faced the entire country has obviously affected our industry as well. It is much more difficult to go out there and get that credit in general. It is more difficult to go get it specifically when the price of crude has fallen so dramatically.

And lastly, the President has proposed a budget that has a $31.5 billion increase in taxes on our industry, primarily from the tax treatments we get for drilling new wells. Tangible drilling costs, percentage of depletion, geophysical and geological deductions that we currently get, the President has proposed to eliminate those. Those are treatments that we have had since 1913 in recognition that they want to encourage this risky business because it is in the nation's best interest in order to have that infrastructure and meet our energy needs.

On drilling rig availability, just some numbers to put it in perspective. In July of last year nationally there were 2400 active drilling rigs in the country and six months later that was cut in half, 1200 rigs.

It basically took us the better part of four or five years to get to that 2400 number and it only took six months to basically mothball that capital and layoff that personnel. And when we go to, if the demand in fact turns around it is going to take some time to revamp up.

Historically to give you a perspective, 1981 was the peak, 4,500 active rigs in the nation. Six years later just 663. So a very cyclical industry that we're facing. And given that we don't own the drilling rigs we do depend on those companies in order to have access to those drilling rigs when, in fact, we want to go out and get the new resources.

The cost tends to be a lagging indicator. It tends to -- as the price increases it lags before the price increases and when the price drops, the price of crude, the price and expense of drilling tends to lag. It's now begun to come down because we have had those costs

decrease and because the demand on the rigs are lower.

This is going to have, as we are looking into future. If and when we are successful in getting the economy back we are also probably going to look at energy demand globally coming back very strong. Prices rising and the demand for drilling rigs increasing.

You will see that, as I mentioned, it doesn't take much time to mothball that capital and that personnel. It does take a long time to revamp up. And so that's something that we are going to have to look at.

And I mentioned the effect it's had on production. They predict that in 2009 domestic production will actually increase from the year prior for the first time in a long time because of all the activity. And so that gets to the question that yes, it is possible to stem the decline curve.

Obviously you have to have permission from the various local, state and federal agencies. We deal with the Endangered Species Act which requires consultation with Fish and Game, Fish and Wildlife, local agencies and the like.

And that has to not only mesh with getting permission but within those permits there are specific biological calendars. There's mating seasons. Particular endangered species which you are not allowed to drill.

So when you combine the drilling rig availability, which at the peak it was six months to a year that you had to wait for a drilling rig. And then you have this biological calendar and you have to go get permission through these consultations, you can see how difficult in some parts it is to make that all match up. That you request six months to a year a drilling rig, not yet having permission from the agency to go drill and hoping that you make that biological calendar. So that's a difficult hurdle that we face as well.

Often when we are in sensitive lands we have to offset those lands for species and you can do that through Habitat Conservation Plans. However those are very difficult to get approved. Kern County has been working on a HCP for 15 years and have not been successful at getting it. But we continue to work at it and we are hopeful that they do. So companies are having to go to other land banks or do their own HCP in order to get

offset lands in order to continue to drill in those areas.

Obviously air rules are a big concern and something that we look at. We have very stringent air rules which we have been complying with for 15 years successfully but there are some issues there on the horizon. As you might have heard in the South Coast there was a lawsuit on the air credits that have prevented those air credits from being used because the air district was sued by environmental groups and NGOs. And so those credits are no longer available for new production. So issues like that are very much at the forefront in our ability to drill more in the future.

There are also water rules. This is very intensive. In some areas basically we have water companies that make a little bit of oil. THUMBS and Tidelands down in Long Beach actually have a 95 percent water cut. So they are taking out, what is coming out of the well is about 95 to 97 percent water and just a small sheen of oil. So then it's very intensive, energy intensive to do that and to reinject that water and all the rules that go with it.

Bob Poole mentioned offshore the state and federal moratorium. But I did want to just expand on that a little bit. One of the things he mentioned was that MMS estimates that there's ten billion barrels in federal lands in the OCS off the Pacific coast. As a point of reference, that's a 1985 number. Obviously there hasn't been a lot of seismic activity done in the last 25 years because of the moratorium.

And as a point of reference, the MMS at that same year predicted that in the Gulf Coast there were nine billion barrels of oil available in the OCS. Twenty-five years later after 6,000 platforms were installed in the Gulf, 4,000 of which continue to operate today -- we have just 27 but they have 4,000 that are operating today. Twenty-five years later we now predict that there's 45 billion barrels of crude in reserve. So that gives you a sense that they were off by a factor of five and so these may be very conservative numbers when it comes to the ten billion that's available off the California coast. So I just wanted to mention that.

Also I wanted to mention, Bob mentioned the specific proposal that went before the State

Lands Commission by Plains Exploration, the Tranquillon Ridge Project. In some of the documents that were part of that process it predicted that at the peak, which it would take about two years to drill and reach the peak of production, you may see 30,000 barrels a day in production from that one project.

So to put that in perspective. If we are making 650,000 barrels a day and you have got 30,000 increased barrels from one project, you know you are looking at somewhere between 18 and 20 percent -- I'm sorry, somewhere around 5 percent increase in just one project. And so that could overcome some of the depletion and other parts of offshore.

And that's just one project. Obviously Veneco's project in Carpinteria and other prospects that there are with the directional drilling, you can see that we legitimately can answer that first question, yes, we can slow the decline curve if we have access to those resources.

We have been engaged at the federal level on the federal moratorium. There have been different proposals about bringing the moratorium

back in a more limited scope. The Speaker of the House said that she recommended maybe the first 50 miles the state can buy in and from 50 miles to 100 miles there would be no moratorium.

Well none of these ten billion, or virtually none of these ten billion barrels of oil exist beyond 100 miles. I don't know of any company that is interested in going out 100 miles off the Pacific Coast in those waters installing platforms and so that is in fact a moratorium.

What we have suggested is that if a limited moratorium has to come back let's look at utilizing our existing infrastructure, our 27 offshore platforms as well as onshore locations, which we can use directional drilling to reach those. And we can reach a tremendous amount of those 36 disputed leases as well as other resources that may be out there on the offshore if we had a moratorium that limited it to existing infrastructure or onshore locations.

And just quickly on the individual market dynamics. One thing is you always hear about WTI, West Texas intermediate price. That's the price we hear on the television every night what it is. But there is always a differential

between California crude and WTI price. And that is not always based on gravity. It is based -- because our light crude also has a differential.

But you can see that it has changed quite a bit recently. Typically over the last three to four years it has ranged from $10 to $15. In July of last year it was $14 when WTI was $147. But in February despite WTI going down more than $100 a barrel the differential was still $10. And so these are the individual dynamics that companies can consider on whether to invest specifically in California.

What causes that? There's a whole host of things that cause it. We talked about the ANS, which had an export ban when it was first produced. So much of that crude, 1.5 barrels were dumped on the California market and that suppressed the price for heavy crude.

ANWR is unlikely to be opened up in this Congress with this president. However, all the bills that are introduced do have provisions in them for this export ban. And this is an actual molecule export ban that this barrel of crude that is produced cannot go to, cannot travel anywhere outside the United States. We suggested that you

can have an export ban by being able to trade so that you don't have these market mechanisms that suppress the price here in California and in turn reduce the drilling operations in California.

We talked a little bit about Big West and Flying J. The bankrupt refinery down there that is no longer purchasing crude. They purchased tens of thousands of barrels a day from folks in Kern County. That went away and so folks had to scramble to deliver that crude somewhere else. There is also an application for a San Joaquin pipeline that feeds crude to Martinez to be shut down for heavy crude which needs to be heat-treated. So those are specific issues for Kern County about whether or not you strand those assets in Kern County.

And then obviously if you had a California severance tax of 9.9 percent, which they contemplated, that would further drive down the attractiveness of coming into California to invest.

AB 32, quickly. Right now we are operating under uncertainty. There is no statewide program. There is no recognized thresholds of significance. When people are doing

EIRs there are no recognized mitigation measures. And so there's a lot of uncertainty on how to comply today. Obviously CARB is in the process of developing a Scoping Plan and possibly a cap and trade market to take care of that. But today we operate under uncertainty. And where there's uncertainty and where there's a vacuum folks move in to fuel that vacuum.

In California it's largely been the attorney general who has come in and sued certain local agencies that are considering projects, particularly projects that we are talking about today, and forced his own opinion as far as what the significance levels are, what the mitigation levels should be. And obviously we would all benefit if there was a program that is agreed upon, that we all live under the same rules.

Cap and trade is something that we support, provided that the credits that you can operate with are allocated and not auctioned off. We should do this in the most cost-effective way and auctions are a way to raise a great deal of money. However, it is also a way to raise the cost of complying with AB 32.

We are looking at will the federal

government come in and supersede the state. Obviously when you have a cap and trade program for something that is global in nature the larger the market the better. And so we support a federal program superseding any state program, because the larger the better.

I think the Low-Carbon Fuel Standard largely will not affect production in California. Because CARB I think wisely has chosen to give one carbon score to all feedstock, all crude feedstock. So I think we are going to be okay complying with the LCFS.

And there's also opportunities. CO2 capture and storage has been talked about. It's a big opportunity not only to enhance oil recovery but also a mechanism that others can use in order to store CO2 that's produced by other industrial uses and help us comply with AB 32.

And with that I will be happy to take any questions you have.

PRESIDING MEMBER BYRON: Very good.

ADVISOR BROWN: Could I ask one question, Rock?

MR. ZIERMAN: Yes.

ADVISOR BROWN: How does the Low-Carbon

Fuel Standard treat oil sands?

MR. ZIERMAN: I believe that there is going to be -- the one carbon score is going to be for traditional feedstocks, which that obviously would not be. And so what they propose is to have a separate score perhaps for non-traditional feedstock. But give them an opportunity to do studies, to demonstrate that their actual carbon score may be lower than that one, than that one, thank that CARB sore that they give them. So that's my understanding of where the discussion is today.

ADVISOR BROWN: So it is conceivable they will use some kind of life cycle cost analysis to --

MR. ZIERMAN: Correct.

ADVISOR BROWN: -- arrive at the right score for conventional versus unconventional.

MR. ZIERMAN: Right. As a lot of Canadian companies have been participating in this process they have been mentioning programs that they are implementing similar to AB 32 in order to reduce their carbon footprint and get closer to the same carbon footprint as California production.

VICE CHAIRMAN BOYD: Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Zierman.

MR. SCHREMP: And just for clarification, Rock. You said the Air Board has one carbon score for traditional. Does the Air Board consider enhanced oil recovery using a lot of steam injection as traditional?

MR. ZIERMAN: Yes, my understanding is yes. Anything that is part of the feedstock today in California, which certainly EOR oil is, would be given that one carbon score.

MR. SCHREMP: And then if you could just quickly. Was there a main reason or reasons why the request for Tranquillon Ridge as rejected or denied?

MR. ZIERMAN: Well obviously I don't sit on that panel and don't have, can't get in the brain of those folks that are in there. But obviously we are disappointed given the support amongst environmental groups and all the benefits that went with it. I think at the end of the day offshore production is a very, a very scary issue for a lot of decision makers and they don't want to get tied into being perceived as pro-offshore oil.

However, we have done numerous surveys. And when it comes to opposition to offshore we think that the main thing the public objects to is the installation of new offshore platforms. And obviously this is a project that would not do that. It would utilize existing infrastructure. And in fact, as I mentioned, we can get most of those resources from existing infrastructure. So I think at the end of the day probably some people had a negative reaction to the overall issue given their political futures.

MR. SCHREMP: Thank you very much, Rock.

We have Dominic Ferrari from Plains All American.

MR. FERRARI: Good morning, Commissioners, members of the audience. My name is Dominic Ferrari, vice president of Plains All American Pipeline. I am in charge of all of our operations on the West Coast and predominately California. I am here today to speak on behalf of Plains on the Pier 400 Project.

A little background, quick background on our company. As you may or may not know we are headquartered in Houston, Texas but we do have a significant presence here in California. We have

a major office in Long Beach, Bakersfield, where we manage most of our assets.

As a lot of the speakers mentioned this morning there is a serious lack of infrastructure in California, especially in Southern California. So I am not going to dwell on that, I am really here to give you an update status on our project.

Again a lot of these discussion points you have already heard about domestic crude declining and a lot of the assumptions. Several speakers have hit on this so again I am not going to go over it. Our project, though, is an import facility and you will see hopefully it will be a solution.

A little bit about the project. And I've got some maps coming up to show you. We call it Berth 408. It's in the Port of Los Angeles.

Number one, it's got 81 feet of water. Basically it will be able to handle any vessel from anywhere in the world. This is very significant because, as you heard, we are expecting, unfortunately, Middle East crude to keep coming. And it comes in VLCCs and those guys need deep water. If you don't have deep water they have to lighter and do other things and it

just drives up the cost. So this is a key point of this infrastructure project.

The capacity is significant. We are designing it for an initial capacity of 350,000 barrels per day so this is a major facility.

And of course we always build in provisions to expand over time if the market dictates.

The project also includes a significant amount of storage. When you build a project like this you need a lot of storage tankage to handle the crude oil so we are planning initially on four million barrels of storage tanks.

The offloading rates are up to 100,000 barrels per hour, which again is world class. The 100,000 barrel per hour offloading rate. There's probably one other terminal in the United States that does that off the coast of Louisiana. Again, this is a world class type of facility.

Obviously we were designing this to be very environmental, environmentally friendly.

And safety and security are absolutely key in a project like this.

A little map here to show you, give you an idea of the project. If you look out on the

water you can see an arrow pointing at Berth 408 and you can see a vessel there. That's where a vessel would come in and offload. There's a 42-inch pipeline that would connect that area and go around the Pier 400 land mass over to where we show the project tankage. And that, again, would have our 4 million barrels.

The key to any facility like this is to get the vessel in, offload them real quick and get them out. They are very expensive and they need to, they can't sit there. So this is all designed to get these guys in and out.

You can also see the entry where it says Berth 408. That is called Angel's Gate. That's where the vessels come in from the Pacific Ocean. And you can see the access to our dock is very simple. It's all been designed that way. The people, the Port of LA designed this land mass and they did a wonderful job as far as being able to get vessels in quickly, safely and out. It's kind of an overview. And you can see the town of San Pedro right below there, to give you an idea of where this is.

This is kind of a busy map but the whole point is that again it's one thing to build a

facility like this and build tankage but at the end of the day you've got to get it to the refineries that we discussed this morning.

Our company owns and operates a significant pipeline infrastructure in Los Angeles with tankage. We are already connected. We already serve all the refineries with our pipelines from Bakersfield. We operate two major pipelines from Bakersfield to LA and we supply all refineries in Los Angeles. So the good news is here we don't have to duplicate or replicate any more pipelines an tankage in LA. It's all there and it will be hooked up to our Pier 400 project.

Okay, let's get to entitlement. This again has been a long road. I think Commissioner Boyd mentioned earlier that this has been going on for awhile and it sure has. But we feel we are getting close.

The main steps to get this thing going is to get approval, final approval of our EIR and EIS.

We are still working on a Harbor Commission approval for land lease.

We need City Hall approval of our Harbor Department permit.

And we need an AQMD permit. And I'll talk about these items in a minute.

We did have a little delay in our CEQA process here recently.

It really caused about a two-year delay.

Bottom line is we obviously had to perform an EIR.

And that process, even though it was long it actually went pretty well. But we had a protestant right at the end and that caused us a significant amount of time to deal with. The good news is that we have been able to answer all those questions and get our EIR back on track and I'm going to talk a little bit more about that.

Capital costs have gone up on the project. Again, it has been going on so long. But it's kind of interesting. Last year as you all know we had steel going through the roof and we couldn't find contractors. Canada was taking all of our contractors. That's all been reversed. Steel is coming back down, contractors are hungry, so we actually have seen a reversal in this trend and pretty, pretty optimistic about our ability to control our capital on this project.

This project, again it's a significant

project. It would employ a lot of people, a lot of construction people in LA and a lot of permitted operating jobs. So we are anxious to get this going for that reason.

This is a timeline that I don't know that I'm really going to bore you with, other than I guess the whole point is that we did apply to the Port of LA in April of 2003. That's when we got this kicked off. And actually we were here to introduce the project to the CEC in 2003. I am not going to go through all of the steps but you can see how long it takes to get this done.

The key bullet point here is the current station and construction period.

Our draft EIR was approved by the Harbor Commission in November of 2008. It was a unanimous vote by the Port of LA Harbor Commission and we were very, very thrilled about that. But we did get the appeal in December and that was our latest setback. Now again, we've dealt with that.

Our EIR and land lease goes to vote today to the City Council. So the LA City Council is voting on our project today. So we have got our fingers crossed. We believe the City is going to support us. Certainly with the Harbor

Commission giving us a positive vote we would be very surprised if the City didn't but we have gotten surprised here a couple of times so we are just going to keep our fingers crossed. With an LA City Council approval today we will be in very good shape. There is always an appeal period but I think we will be in good shape after today's vote.

As far as moving on here's a couple of more bullet points. But the bottom line, to get to the bottom bullet point. It's going to take a couple of years to build this. Again, it's a major facility. And we are projecting opening up the facility for business in early 2012. So bottom line is we need a couple of years to build this as long as we don't get any more delays.

This was a slide on supply and demand. And again I am not going to go through this because there has been excellent presentations on this today. The only thing at the bottom is here we do talk about the other berths in Southern California that are handling oil today.

And you can see some of the problems. For instance, 121 in Long Beach. That is a significant facility but it's maxxed out. BP/

ConocoPhillips basically dominate that dock and nobody else can get in. Tesoro is a smaller facility, can't really move a lot of oil in there. And ExxonMobil is being take out of service so we have got a real problem there. Chevron has their own facility. Again, they are running a lot of Middle Eastern crude, as was discussed this morning.

VICE CHAIRMAN BOYD: The ExxonMobil that you say is out of service. Is that a permanent out of service?

MR. FERRARI: Well.

VICE CHAIRMAN BOYD: It sounded like it.

MR. FERRARI: Commissioner, it's kind of a sensitive subject. But, you know, the whole, the whole principle behind the Pier 400 -- let me see if I can go back real quick. The whole principle behind building Pier 400. You know, it's a manmade island. If you look where it says Maersk and Berth 408, that's 400 acres of land mass that was put in by the Port.

They got federal funds basically to move the oil operations away from the inland area. The Exxon terminal and other terminals are located in these inner waterways and they are close to the

public. So the whole idea of building Pier 400 was to move oil out and get it away from the public. Exxon is on that list.

VICE CHAIRMAN BOYD: Okay. I kind of know the history of Pier 400. All those cargo containers weren't assumed to be there in the beginning, if I remember right.

MR. FERRARI: That's correct, Commissioner, it was supposed to be an all-oil facility. But because of delays and difficulties and getting things permitted the containers came in. But we still, we still have a spot to build our project.

VICE CHAIRMAN BOYD: Thank you.

MR. FERRARI: These are just some other comments we had today about other, other facilities. As you all know MOTEMS, the State Lands came out with MOTEMS. And a lot of the facilities are complying with MOTEMS and upgrading their docks. And we see that as definitely a positive and the other operators upgrading their facilities for safety and security reasons. So I think that's a real positive development California State Lands implemented. Obviously our facility is going to be designed according to

MOTEMS.

On the other hand a lot of the facilities are old. They have wooden piles. They are just, you know, 50 years old or higher. Some of the facilities are going to get upgraded with MOTEMS and some probably will go by the wayside. So we'll just have to see how that goes.

That concludes my presentation. It was really, really an update on our project. If you have any questions I'd be happy, happy to answer them.

VICE CHAIRMAN BOYD: No more from me.

ADVISOR SCHWYZER: I have a question, actually.

PRESIDING MEMBER BYRON: Go right ahead.

ADVISOR SCHWYZER: I noticed one of the permits you still need is the AQMD permit to construct. Do you anticipate any difficulty with that one?

MR. FERRARI: No, not at all. The permit is actually already, already drafted. But the way they work is they wait until the final EIR is approved and everybody is signed off and then they, and then they actually give you the piece of paper. So it's done, we have no more

negotiations. But, you know, we don't actually have the paper yet. But we'll get it. Very confident.

PRESIDING MEMBER BYRON: Mr. Ferrari, probably I should know this but I'll ask. Which organization had the CEQA responsibility in your permitting? Is there a single agency that it's --

VICE CHAIRMAN BOYD: Who is the lead agency?

PRESIDING MEMBER BYRON: The lead agency.

MR. FERRARI: We had two lead agencies. The Port of Los Angeles was the lead agency for the EIR and the Army Corps of Engineers was the lead agency for the other. So we had two, two lead agencies. And again, the Port of LA is a very, very, very good agency to work with.

PRESIDING MEMBER BYRON: Well, and I realize you are up for a vote today so this might not be the right time to ask this question. But you have made a recommendation here that CEQA process be reviewed and modified to minimize the ability for minor issues to be allowed to delay important projects. So if you don't care to answer this question today I'd understand. Maybe

though you could let us know in writing in the future what specific recommendations you might have along those lines.

MR. FERRARI: We would be very happy to kind of do a look-back on this project with you and put some things down in writing. Because obviously it has taken five or six years, you know, the permit. And we understand it's a major project but there are little things that come up that just, you know, really shouldn't stop a project like this or slow it down. Really not ready to talk about it today but we do, we would like to do a look-back.

I will say one thing, if I had a couple of minutes. We came up and presented this project to the Energy Commission when we first started five or six years ago. And at that time we were getting a lot of heat from one agency that I am not going to mention. The Commissioners listened to what we were saying.

And basically at that time, I don't know if Commissioner Boyd remembers, but you guys were thinking about streamlining, going to streamlining and basically just taking over the permitting. And after that meeting, I'll tell you, things

opened up, things really got easy for us. So we appreciate that one stance that you folks took six years ago. I can't tell you how much that changed people's attitudes.

VICE CHAIRMAN BOYD: Yeah, well we got a lot of bruises.

MR. FERRARI: Yeah. Do you remember that, Commissioner Boyd?

VICE CHAIRMAN BOYD: Yes I do.

MR. FERRARI: Well that was very effective, thank you.

PRESIDING MEMBER BYRON: All right, well Commissioner Boyd will clue me in later. But we would be interested in your recommendations when you do that look-back. I think that could be very helpful to this Commission.

MR. FERRARI: Very good sir. We will provide it, thank you.

PRESIDING MEMBER BYRON: Thank you for coming.

MR. SCHREMP: Thank you very much, Dominic. The next speaker is Seth Jacobson.

MR. JACOBSON: Thank you very much for inviting us to speak today. My name is Seth Jacobson, I'm from CAST. We are a California-

based nonprofit organization that was founded in 2005 by national security professionals, including Dr. Abraham Wagner who leads the organization. He served under five different presidents at the federal level, including on the National Security Council, and was director of DARPA for awhile.

We also co-host an annual conference with RAND down in Santa Monica on terrorism and global security. This analysis was originally developed for our 2008 conference. It's a work in progress. Our goal is to evaluate the growing vulnerability of Los Angeles and California to disruptions in the global supply chain, particularly from terrorism.

As a summary, and as had been said before by other speakers today, we Californians are increasingly vulnerable to terrorist attacks on our oil supplies. This is a politics and economics issue.

And with that in mind as we look forward to US withdrawal from Iraq we believe that the withdrawal will heighten California's vulnerability and that we Californians should implement policies to develop resilience to disruptions in the supply chain.

And one policy recommendation that we are making is the development of a strategic petroleum reserve in the western US to provide surge capacity.

This is just a reflection of what's been mentioned earlier and is from the CEC website. We are past peak production, domestic production peaked long ago, and we are increasingly reliant on unreliable foreign sources for our oil consumption.

An attack on LA's oil imports is not simply Los Angeles's problem. As has been mentioned the refineries in Southern California serve about 25 million Americans in the southwestern United States. And of course we have imports into the northern refineries in Northern California as well. But obviously disruption will cause major economic damage to the region.

This is based on a chart that was presented earlier today from the gentleman from Baker. We down in Southern California, our refineries already use a majority of foreign oil. It was mentioned yesterday that the United States imports about 60 percent of oil consumption. Southern California has about, I think, 56 percent

now of our refinery runs are foreign imports.

But all foreign imports are not created equal. The source of those imports is really important for us to take a look at.

As was also mentioned earlier, I just want to reiterate that in about five years it is projected that no oil will be coming from Alaska to Southern California's refineries. At which point the overwhelming majority of the oil consumption will be foreign imports, primarily from the Middle East.

The reason that this is important, of course, as I mentioned earlier, is that all imports are not created equal. Since 2003 with the invasion of Iraq the number one source of foreign imports to Southern California's refinery is Iraqi oil, surpassing Saudi Arabia and Ecuador, which is not on this chart. For all intents and purposes Los Angeles and Basra are now sister cities. Although this chart shows that LA is comparatively less reliant on Saudi crude, Saudi Arabia is still the number one foreign source of oil for California.

A more recent analysis in the last few weeks. We wanted to see what the impact of higher

oil prices last year and the recession might have been on imports to see whether there may have been a silver lining from the demand destruction on consumption. Unfortunately what we found is that it was all pain no gain and our imports from Iraq and Saudi Arabia stayed relatively consistent and our foreign oil imports also stayed relatively consistent.

So we Californians really need to think about petro-terrorism and the disruption to oil supplies. Al-Qaeda is one group of many globally that for political reasons engage in petro-terrorism. They are very good at it. They have been very effective in Iraq. They have also attacked facilities in Saudi Arabia and carried out attacks in Yemen.

And they tend to repeat their attacks on targets. So for example, that attack in Saudi Arabia on the Abqaiq facility wasn't as effective but we expect them to attack again.

And I wanted to reflect a little bit on what was mentioned earlier in terms of imports not only from the Middle East but from West Africa and Latin America. We should get specific.

You know, with regard to Latin America,

as I mentioned before, primarily those imports are from Ecuador. Ecuador is not a reliable supplier for California. They are antipathetic towards -- at least the government of Ecuador is antipathetic towards the United States. They have been nationalizing their oil assets. They kicked out Occidental. And they have also have been known to harbor FARC guerrillas, who are actually more effective at bombing pipelines than Al-Qaeda is.

With regard to Mexico, at least in Southern California, we don't get much oil from Mexico. But were we to start to rely more on Mexico, there have been attack by leftist guerrillas. Very effective attacks that have signatures of Al-Qaeda's tactics. So there is information sharing that has been very effective, whether directly or simply posted on the Internet and shared that way. But those attacks in Mexico, according to the Mexican government, did hundreds of millions of dollars in economic damage per day.

And then with regard to West Africa. If we were to become more reliant on Nigerian oil, that may not be such a good idea. As you may know in the last few years the tribal groups like MEND have been extraordinarily effective at shutting in

oil production to the tune of, I think at this point about 25 percent of oil production in Nigeria is shut-in.

So that we are reliant on Middle Eastern oil, and Iraqi and Saudi Arabian Oil, is not to be solved by simply importing from other parts of the world.

But getting back to Al-Qaeda, just as a brief backgrounder. Their primary goal is to drive the impure from the Islamic world and establish a Caliphate. Impure would include us Americans.

And their strategy has been explicitly stated as bleed until bankruptcy, at least with regard to the United States. They are going to inflict unbearable costs on the US economy, erode US public support for funding the war and therefore stimulate regional withdrawal. And I'll leave it up to you to see or decide how effective they have been so far.

Their tactics are known as Fourth Generation warfare. That was developed by the US but now they claim it as their own and have interpreted it in their own way and are very explicit about it.

But the bottom line is that they are very effective at using networks to strike from a distance. Whether they are communication networks or transportation networks or energy networks they are very good at it. And again, it is political and it is economic and it seeks to inflict economic cost.

So how does that impact us? Well, as has been said over and over in the last day, we are heavily reliant on global supply chains. And what we at CAST are looking at is, you know, is that threat domestic or is that foreign or is it both? And we tend to think that it's both. That is to say, from an economic perspective and a return on investment, which they are very explicit about and I'll get to that in a bit in terms of their analysis of attacks. It's cheaper to attack overseas but hit us at home by disrupting those foreign sources of oil.

And so more on ROI. Of course return on investment does correlate with the price of oil. And we saw increased attacks globally but certainly in the Middle East when the price of oil was higher. They are explicit about this. I mean, these are very smart, sophisticated people

who are looking at costs and benefits just as we might from a policy perspective.

And so a higher return on investment, that is to say a higher oil price or reducing costs, increases their incentives to attack. It sounds extremely simple, and I guess it is, but it also is common sense. So right now with the price of oil a little bit lower, or a lot lower certainly than last summer, we think there may be less incentive to attack.

And in terms of the final bullet point. You know, I just want to emphasize that we are not criticizing US foreign policy here. We are looking at what may be, and therefore what the threat may be, to domestic oil supplies with regard to foreign policy.

So if we are to withdraw our forces from Iraq we think that raises the potential of a lower cost for an attack by, by anybody who wants to engage in an attack on oil infrastructure in Iraq. And higher oil prices projected by simply looking at the NYMEX futures market, an increase of about 40 percent to about $70 a barrel by the end of 2011 when we are projected to have pulled out entirely.

So that's just simple math. And it may be a simple analysis. And again, this is a work in progress. But that would be a higher return on investment for anybody who wanted to attack.

And this is not just Al-Qaeda, there are many other groups who are engaged in fighting over oil assets in Iraq. So overall we just think that it may increase the threat of disruption. I mean, it's something that we Californians need to prepare for.

So again, you know, the approach that we take is that we believe that California needs to build resilience. And thankfully from a policy perspective that has been very much California's state of mind on a lot of different fronts, beginning with earthquake preparedness, and generally speaking, in terms of emergency management.

So as California has been on the leading edge of that sort of thinking with regard to other crises, we just suggest that the CEC and other California policy makers consider applying that thinking to disruptions in the oil supply chain.

One way of doing that is of course reducing consumption. And we certainly advocate

that. As much as I am standing up here and suggesting SPR-West, I drive a car that runs on biodiesel. And I think that California has certainly been on the leading edge of trying to develop policies to reduce consumption.

Unfortunately, reducing consumption doesn't necessarily mean reducing imports. And this chart is based on CEC staff analysis on AB 1493. And we applaud these efforts but we are not sure whether they are going to be effective in solving the problem of oil supply disruption from foreign sources.

And so in the meantime while we are working out these policies to try to reduce consumption we think we should plan as well for a disruption in a more immediate way and that is to say, build SPR-West. And obviously it will take some federal dollars. But the federal dollars that it will take are less than we are currently spending on a monthly basis in Iraq. So we think those can be justified. Thank you.

VICE CHAIRMAN BOYD: Thank you. A quick question if I might. To what extent are you aware that there is discussion of this issue at the federal level, i.e. the West Coast isolation and

all that you have laid out for us?

MR. JACOBSON: We think that there has been a bit of discussion at DOE but unfortunately it has not been made a priority. And as has often been the case, the East Coast doesn't really make the West Coast a priority in terms of policy making and spending dollars.

VICE CHAIRMAN BOYD: You mean the Left Coast, as they call us.

MR. JACOBSON: Yes.

PRESIDING MEMBER BYRON: And we return the favor too.

ADVISOR BROWN: I had a question too. Are you advocating a physical reserve or a paper reserve?

MR. JACOBSON: A physical reserve.

PRESIDING MEMBER BYRON: Commissioner Boyd, are we losing you shortly? Are you here for a few more minutes? Can you entertain a few more questions on this topic?

VICE CHAIRMAN BOYD: Yes.

PRESIDING MEMBER BYRON: Okay.

VICE CHAIRMAN BOYD: I do have to leave shortly.

PRESIDING MEMBER BYRON: This was a very

interesting presentation. And while you were making it I was sitting here realizing that as much as I don't like to talk about the subject I have read some interesting books on it recently. But some questions came to mind.

In fact, I am reading one right now on the bombing of the LA Times building. The crime of the century last year that killed 22 people. Of course that was domestic terrorism, which leads to my first question. Does the recommendation that you are making apply as well to other forms of terrorism that we should probably be concerned about as well, domestic terrorism?

MR. JACOBSON: Yes. I mean, in terms of resilience, yes, absolutely. You cannot harden all targets. You need to -- a lot of it has to do with preparing people to rebound. And so yes, we are big advocates for that.

PRESIDING MEMBER BYRON: Well, and you know, we have other vulnerabilities that we deal with as well in our energy infrastructure. Does your organization deal with or concern itself with the electric supply and delivery exposure?

MR. JACOBSON: This analysis does not apply to that but yes we have.

PRESIDING MEMBER BYRON: Okay. I would be interested in some more information on that as well from CAST.

MR. JACOBSON: Okay.

PRESIDING MEMBER BYRON: And other question that came to mind is why don't you also recommend we open up access to other domestic supplies here in the United States?

MR. JACOBSON: Well we are not opposed to that. We just are simply trying to focus on what we think is the low-hanging fruit. And given the political mine field that is opening up offshore drilling, we think that it may be easier from a policy perspective to at least get federal and state policy makers to agree to build out this reserve first.

PRESIDING MEMBER BYRON: But it seems to me it only addresses the tip of the iceberg, if you will.

MR. JACOBSON: Yes.

PRESIDING MEMBER BYRON: Once we finally have the reserves here in the United States.

MR. JACOBSON: Well, those reserves will be depleted over time as well. And so we think that -- well first of all there are no silver

bullets here. We are not saying that this is the core solution to our problems. What we are saying is that this simply builds surge capacity so that, so that in the event of a disruption the economic costs won't be as severe while different stakeholders seek to reallocate oil supplies to California again.

PRESIDING MEMBER BYRON: Well thank you for your presentation and thanks for coming.

MR. JACOBSON: You're welcome.

PRESIDING MEMBER BYRON: Commissioner Boyd, I am going to suggest we take a break just for a couple of minutes. But before we do I think we may be losing you. Did you have any comments you wanted to make?

VICE CHAIRMAN BOYD: Well, were I to make comments it would just be to thank everybody so far. Apologies to the other speakers but I know they are in good hands with you and the rest of the folks. This has been very interesting to me. I don't have any findings as such. I think I have a long laundry list of things we need to pursue.

This last issue is one we have talked about before when we debated the wisdom of a

strategic finished fuels reserve several years ago so it's not the first time we have talked about this. But the world has changed quite a bit so I think we will have to talk more about it. Otherwise, thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Jacobson.

MR. JACOBSON: Thank you.

PRESIDING MEMBER BYRON: We are going to take a ten minute break out of necessity. We will start promptly at 11:10. Thank you.

(A recess was taken off the record.)

PRESIDING MEMBER BYRON: Let's go ahead and start since I said we should start promptly at 11:10.

We have I think one more session to go through on petroleum and renewable product pipelines and then some opportunity for public comment. Gordon, would you go ahead and do the introductions for this session.

MR. SCHREMP: In fact I will do more than that, Commissioner Byron. I will provide a little bit of context with some background as I did with crude oil but not as many slides.

So just to I think reiterate some of the theme that has been circulating the last day and a half. California, with regard to transportation fuel, and other forms of energy, it's a regional, it's a regional supply/demand center, essentially. We and other states are interdependent on one another for supply.

California is primarily a source of supply for the neighboring states of Nevada and Arizona. And that's very important because that affects how much petroleum products are moving from California to those two states. and that in effect has a demand draw on imports through our marine infrastructure and pipeline infrastructure. So that's why we pay attention to it. But there is even a larger interstate regional supply/demand balance interdependence.

This is a focus of, this is a Kinder Morgan map of their system. We saw some of this yesterday. But the map depicts the green line that goes into the Las Vegas supply region, which is predominately most of the product that goes into Nevada.

There's a line that goes into Reno. And then the lower red lines are the supply pipeline

that into Phoenix from the west, we refer to it as the West Line. And the two lines you see coming from El Paso, Texas all the way into Tucson, those into Phoenix, those are actually referred to as the East Line. And this is important because that line was actually expanded recently and had an impact on the supply/demand balance.

So we work with Nevada and Arizona to look at their demand forecasts. We sort of developed that together, working with them to obtain information. And we estimate what their demand will be for all primary forms of fuel, gasoline, diesel and jet fuel.

We look at that demand and we say, well how will that be met? Well for Nevada primarily the list point would be through pipeline exports from California to that state. But with the announced project of a Utah to Northern Las Vegas pipeline that will change the supply demand outlook if in fact that project does move forward. But we do plan on obtaining some information from Holly Energy Corp. on that project. They were unable to speak today, unfortunately, but they can provide some information on the status of that project as far as the IEPR process.

Arizona is supplied from two different regions. Duane Yantorno, the next speaker, will address that in more detail. But a key take-away is when you look at this slide is all of the transportation fuels we have exported to the neighboring states, Nevada and Arizona.

As you can see there has been a decline since the peak in 2005. And why I titled the slide Indirect Supply, that's exactly the effect it had. As our exports declined to those two states more petroleum products were available for use in California and it took a little bit of pressure off the marine import infrastructure.

So this indirect supply was almost exclusively a consequence of the East Line being expanded in capacity. And what happened is more supply started flowing from West Texas going into Arizona than out of California. And the supply shift was rather dramatic. In 2002, 63 percent of the petroleum products supplied to Arizona were from the west, from California and/or through California marine infrastructure. Today, or more recently in 2008, that number is down to 34 percent.

So that's been a rather significant

supply shift that's about 76,000 barrels a day and more supply available to the California marketplace. So that's really been a part -- that's been part of, I think, the oversupply if you will and the lowering of the refinery margins most recently. That's been one of the consequences of this oversupply situation and lower crude oil runs at California refineries. That lowered utilization rates.

So the reduction you see in this chart is primarily because of that. Because in fact the deliveries into Arizona from 2006 to 2008 by pipelines from both directions are about equal. So the decline isn't because of reduced demand in Arizona, necessarily. It's because of this supply shift. That's market participants deciding it's more cost-effective to supply from the east rather than the west.

So just to reiterate. We will be looking at what those projections are for demand.

We will be looking at new projects. Both the Utah to Las Vegas pipeline and having it as a scenario. What the impacts are on the outlook for the pipeline exports.

And we will also be including other

expansion projects. The one mentioned yesterday by Kinder Morgan is the increased capacity on their pumping rates from California into Las Vegas.

We heard a little bit about this on Day 1 but I just want to reiterate what Kinder Morgan was expressing and sort of sum up. Yes, they move some ethanol in some of their pipeline systems in other parts of the US, that's correct. Have they moved some biodiesel, B2 or B5 blends? Yes they have. But there are caveats to that.

From what they were describing yesterday it seems unlikely those means of conveying renewable fuels through mixed product pipelines is unlikely to be utilized in California.

Therefore staff will continue with regard to our assumptions that incremental throughput of renewable fuels will have to be accomplished at distribution terminals by increasing the capacity to receive truck-borne cargos of renewable fuels as well as additional storage tanks to store them.

So unless Kinder Morgan provides additional information that they plan to move biodiesel in their California systems or ethanol,

that will be essentially our assumptions in the analysis.

The two speakers we have following me are Duane Yantorno from the Arizona Department of Weights and Measures and Steve Sokolsky from CALSTART. And I believe we have -- Duane is on the line.

MR. YANTORNO: Yes I am, Gordon.

MR. SCHREMP: We are just going to call up your presentation here. I'll be the slide controller and you just tell me when you would like to move on to the next slide.

MR. YANTORNO: Thank you, Gordon.

Good morning, Commissioners. My name is Duane Yantorno. I am the director of transportation fuels and air quality programs for the Arizona Department of Weights and Measures. I would have liked to have been there today with you but as you know state budgets are really tight and so travel isn't allowed; but I have been enjoying the webcast. And the information being presented by the presenters has been really valuable information for us.

As Gordon had indicated earlier, there is a strong interdependence between Arizona,

California, Nevada, New Mexico, West Texas. And so we look forward to working closely with the California Energy Commission on these kinds of issues. Next slide.

As you can see supply to Arizona comes from two major pipelines, as Gordon had alluded to. There's the West Line out of Southern California and the East Line out of West Texas. In addition to that supply is brought in out of the Gulf Coast through the Longhorn Pipeline and we will talk more, a little more about that.

The majority of the fuel coming into the state comes in through these pipelines. We do receive some rail shipments to smaller distribution centers in the northern part of the state. We also receive some shipments or deliveries directly to retail out of the neighboring states, California, New Mexico and Nevada. Next slide.

I want to talk a little bit about, about the timeline associated with this shift in supply. As Gordon had alluded to, this shift occurred. And it was good news for California but created some issues for Arizona.

The timeline associated with this. It

was back in July of 2003 when the Kinder Morgan East line between El Paso and Tucson had ruptured in Tucson, spraying some houses down with gasoline.

It had a significant impact on Arizona's cleaner burning gasoline, CBG, coming from the East Line when the East Line was shut down. We'll talk about CBG simply because CBG represents 70 percent of all the gasoline demand in the state. And so the effects -- the effects on CBG are felt first before we see that on the other more traditional transportation fuels.

The Governor established a task force to take a look at the pipeline systems and to make recommendations to her. The task force looked at not only the pipeline and transportation fuels but other forms of energy supplied to the state. To make recommendations to help make it more secure. As you know we saw some real problems in Phoenix when the supply was cut off and we saw runs on gas stations, fistfights and just real overall problems in 2003. Next slide.

The task force made a recommendation to support the Kinder Morgan expansion of the East Line. Kinder Morgan at that time agreed and said

that, be careful what you wish for. If we had it to look back we would probably still support the expansion but we would have been a little bit more prepared for what we saw as a result of that.

Kinder Morgan developed a two-phase expansion schedule. The first phase was to increase the line size and to build breakout tankage in El Paso.

The second phase was to add pumping capacity.

At about the same time that we saw this increase in capacity of the East Line we also saw increased shipments on the Longhorn Pipeline into El Paso. Next slide.

Phase 1, the expansion was completed in July of 2006.

Phase 2 was then completed in December of 2007. And so you'll see a little lag time in 2006 because they had, they had to overcome some of the start-up problems that they experienced with Phase 1. Next slide.

What we saw as far as the shift in supply distribution. In July of 2003 at the time of the East Line pipe failure we saw 53 percent of all CBG coming into the state coming in out of the

West Line; 42 percent was coming in off of the East Line.

In November of 2006, after the Phase 1 completion was done, we saw the shift to the East Line of 68 percent and the West Line now only supplying 32 percent.

We expected that to kind of hang out there at that point. But with the completion of Phase 2 in January of 2008 we saw a shift of 80 percent coming in off of the East Line and only 20 percent coming off o the West Line.

And we'll talk about some of the effects that we saw as a result of this shift.

In December of 2008 we saw, when Flying J filed for Chapter 11 protection, we saw 10 percent coming off of the West Line and 90 percent off of the East Line.

Currently today, as of February, that supply shift has shifted back towards the West Line a little bit more. We are at 42 percent off of the West Line and 58 percent off of the East Line. So that kind of shows what impact the Flying J and their supply problems resulted in coming into Arizona. Next slide.

This is a graph that we have been

tracking supply off of the East and the West Lines. As you can see we have identified where Phase 1 was, we have identified where Phase 2 was, and some other supply disruption significant events.

As you can see there you saw the shift to the East Line. The yellow is growing as we move forward from Phase 1. You see and you may note that at about March and April of 2007 you see a sharp increase in West Line delivery. That even is specifically related to us losing one of the three refineries on the East Line for supply, and that was the Valero McKee explosion which took them offline for CBG supply. Next slide.

What you see here is Kinder Morgan was right. We needed to be careful for what we wished for. Clearly this created some problems for Arizona.

The East Line refineries. It's clear that the market for the East Line refineries and the Gulf Coast is preferential to Arizona. And so we saw that significant shift.

The economics were such that they could make a lot more money shipping into Arizona than they could going into Dallas or some of the other

markets that they would normally have supplied to.

In November we were up to 90 percent based upon the East Line, coming off of the East Line. And that was tied to three refineries and one registered supplier on the East Line.

So what this has done is this created a sensitivity for CBG supply. And I'll talk a little more about that. Next slide.

Originally Arizona's supply was dependent, back in 2003, basically upon eight refineries off of the East Line -- off of the West Line, excuse me, out of Southern California, and one refinery out of the San Francisco area. So supply problems could be spread out over the eight refineries.

Now supply is simply supplied by three refineries with one registered supplier who has now reduced this amount of supply simply because of them filing Chapter 11 protection. So we have now shifted our dependency on supply from eight refineries to three refineries. Next slide.

Some of the other problems that we saw as a result of this is we saw an increase in the transit time on the West Line because of that reduction, as Gordon had indicated, of 34 or 35

percent coming off of the West Line. There wasn't enough product to move it as rapidly so Kinder Morgan slowed the line down. We actually saw times when the West Line had to be shut down for a time because there wasn't product available to be able to push product into Phoenix.

Another problem of the shift we saw that was the breakout tankage that was originally in Tucson for the East Line CBG has been removed and now that is a direct line directly from El Paso into Phoenix. This reduced some of our flexibility as we saw in 2003. We were able to pull some supply off of the East Line. We could get it into Tucson and then offload it into trucks and deliver it into Phoenix. That flexibility has been lost now.

Ultimately what we found is we saw an increase in the volatility of pricing and supply. More sensitivity to scheduled down time on the three refineries on the East Line. And specifically significantly affected by down time as a result of unscheduled down time on those three refineries. Next slide.

One of the other problems we saw with the expansion of the East Line and it was unique

that we had to deal with. Because of the regulatory requirements for Arizona CBG and the fact that it has to be, it has to come in at specific timing, Longhorn bringing product out of the Gulf Coast ended up with scheduling problems. And the transit time originally out of the Gulf Coast to El Paso was 30 days.

At their peak they were able to reduce that transit time to 14 days.

But any delay at all in that transit time could result in the product being non-compliant. And as a matter of fact we saw. Gordon, if you want to go to the next slide.

We saw that as a result of Ike. And so some of the things that we have seen in May of 2007 -- 2008. On May 7, 2008 Navajo went down unexpectedly when they were having problems with their unit.

During 2008 the hurricane impacts. And this is interesting because what had happened was at one point in time there was almost half a million barrels of CBG that was stranded in the Longhorn Pipeline as a result of Hurricane Ike. When it shut down the Gulf Coast it shut down the Longhorn Pipeline.

As a result of that, that fuel would have come in and would have been non-compliant. The impact was almost a five day supply that wasn't going to come in. When we conducted our analysis of what the supply impact would be we determined that we would be down to about a day, a day and a half of supply here in Phoenix.

We contacted EPA. We then let them know that this was going to be a problem. EPA then issued, granted one of the last waivers, if not the last waiver as a result of Ike so that we could move our fuel standards for the Phoenix area out by two weeks, which would have allowed that transition fuel to go ahead and continue to come in. And it was just the compliance date at retail that we were requesting a waiver for. And so it was effective and we were able to do that.

The other thing that we have seen and we see that now is that on December 22 Flying J filed for Chapter 11 protection. They were a major supplier on the East Line; they were a major supplier out of the Gulf Coast. As a result of that we saw a shift in supply. And again you saw that. We are currently looking at a little better distribution of supply off of the West Line. Next

slide.

The other issue that we found is that as you know, this industry is very economics driven. When supply actually -- when the price goes up then supply will shift. We saw this in -- earlier this year, okay, in January. I think it was January when we saw a 40 cent difference between CARB gasoline and Arizona gasoline. At that time we saw a significant shift of supply off of the West Coast and that continues to this day.

MR. SCHREMP: Duane, just to interrupt you. When you say a difference you mean the prices in Arizona were 40 cents higher than California?

MR. YANTORNO: That is correct. And that gave the incentive for West Line suppliers to go ahead and supply Arizona CBG instead of producing CARB gasoline. And so with that being said, okay, one of the things that we found is that the supply of CBG now is coming from a different group of people. Not specifically refineries but more what I call marketer/blenders. You want to go to the next slide.

Again this just shows you supply. I just wanted to reiterate what we had seen with

regards to Ike, Flying J. The impact that the bankruptcy had on our supply levels. Next slide.

And so one of the -- when we talked to the Governor's Office about this problem, okay, and this increased sensitivity to supply disruption we looked at what the options would be. And understanding the state has no, I don't know what you want to call it, no authority to force these kinds of things to happen.

But we looked at boosting the amount coming from the West Line. All we could do is we notified West Line refineries that this imbalance existed. That that sensitivity to supply exists. And that for purposes of protecting supply they may want to shift some of their supplies to the West Line so that they aren't totally dependent upon the East Line for supply. All we did is communicate that. That's all we were able to do.

Increase the number of Gulf Coast registered suppliers. We tried to do that. We tried to encourage Gulf Coast registered suppliers. What we were trying to get to was creating a dependency on more than just three refineries and we have done that. Again, we have increased Gulf Coast registered suppliers but

again, they are basically coming from the marketer/blender types and not specifically from refineries.

The other thing we wanted to look at was expanding storage capacity to mitigate any prolonged supply problems. That has been done. We have expanded supply -- we have expanded storage capacity at the Phoenix terminals. That was, again it was based upon economics and it was based upon one of the terminals wanting to help with this supply problem. And so they did that and expanded their capacity. And that helps. That helps to expand it to days of supply are closer to five days now as compared to three and a half. Next slide, Gordon.

What we have seen, and I have talked briefly about this, is that with this decrease in demand that has helped mitigate the effects and the increase in storage capacity. So where we are at about 100,000 barrels a day, 108,000 barrels, that allows us the ability to store more and to help mitigate some of the impacts. The problem is that we are dependent upon the economics. More so now because the marketer/blender types are looking to make money. And if the economics shift they

will be the first ones to pull out of supplying the Arizona market CBG.

The additional, one of the additional benefits that we found is that the lower demand has allowed for refineries to operate at decreased throughput rates, which ultimately gives them the opportunity to supply incremental barrels when demand calls for it. That's a good thing. The one problem that we have found is that the increased transit time on the west like results in a slower reaction time to that demand if in fact it was needed. But we'll see what happens.

We did see an increase, specifically an increase in rail demand and rail deliveries of CBG out of the Gulf Coast. This wa the preferred method for delivery considering that Longhorn was having problems meeting their schedule and their commitments.

And that's pretty much where we are. All these things still affect supply. And again, the economic shift, we could see that shift directly back over to the East Line at some point if the economics were to shift against supplying Arizona CBG off of the West Line.

That's pretty much my presentation. If

you have any questions I'll be willing to answer.

PRESIDING MEMBER BYRON: Mr. Yantorno, this is Commissioner Jeff Byron. Thank you very much for joining us today, for giving up your lunch hour there in Phoenix. I was not aware of this issue at all going on in Arizona. I was writing down questions as you spoke and you tended to answer all of them as we went along.

It is kind of interesting that it is not quite the result you would expect with increased access to other markets that it created these kind of shortages. I keep coming back to storage. The storage might be your most helpful friend here in terms of mitigating some of these problems. Is that, is that how you see it?

MR. YANTORNO: Absolutely. And I think that again the economics drive that. They aren't going to build storage if they can't fill it. And so what we have seen is that increase has helped. Additionally there are other terminals in the Phoenix area that are looking at increasing their storage capacity as well.

And you're right, the economics drive everything with regards to this industry. At this point in time you can't go to the West Line

refineries and say, you have got to supply us with more fuel because it just won't happen. The good thing is, is that it helped California.

PRESIDING MEMBER BYRON: Well thank you.

MR. YANTORNO: I will really be interested to see the Kinder Morgan CalNev expansion and what impacts that has on the Nevada market as well as supply coming out of California.

PRESIDING MEMBER BYRON: All right. So I'd like to ask, is there anything else or any other recommendations that you have for us here in California as they affect you?

MR. YANTORNO: I think the biggest thing is already being done, the open lines of communication. As Gordon had said and we agree 100 percent is the interdependency that we have on each other. Without those open lines of communication you can't see what impact is coming your way. And so I think that we continue to work as part of a group that Gordon has put together. Work with them and the surrounding states. And I think that's probably more critical.

PRESIDING MEMBER BYRON: You seem to imply that's fairly new. Gordon, is that new or something you have been doing for a long time.

MR. SCHREMP: Duane is referring to the western states coordination meetings that we conduct once a month, which is an overview of US and regional transportation markets.

We also now are talking about electricity and natural gas, what sort of the more recent price and supply situations are. We talk about renewable fuels, level of profitability at biorefineries, supply/ demand balances for ethanol, and in the future. We have been doing this, conducting this meeting for, I believe -- what is it Duane, about almost a year now?

MR. YANTORNO: Almost a year. I think it's about eight, nine months.

PRESIDING MEMBER BYRON: Very good. Well let's add electrical transmission lines to the list then too.

MR. YANTORNO: I think that's a good idea.

PRESIDING MEMBER BYRON: All right. Well thank you very much for joining us today.

MR. YANTORNO: Well thank you for having me. I have appreciated it a lot, thanks.

MR. SCHREMP: Thanks, Duane. You will be hearing from me next week at our next meeting.

I think we will probably put you on mute right now but we will be circling back to you to work with you as we develop sort of that regional supply/ demand forecast.

MR. YANTORNO: Okay, thanks, Gordon.

MR. SCHREMP: Our final speaker today will be Steve Sokolsky from CALSTART.

MR. SOKOLSKY: Thanks, Gordon. Contrary to popular belief and the agenda I am not Bill Zobel of Sempra. Bill was unavailable. But we at CALSTART share a lot of the concerns and interest in biomethane that they do at the utilities, especially at Sempra.

So Bill asked us to pinch hit for him and give a basic overview on what some of the resource potentials are for biomethane and where it could be applied. Not only in pipeline issues but also from what we are interested in, is the transportation issue and how biomethane could be used as a renewable source of either liquified or compressed gas.

For those who are not familiar with CALSTART. We are a nonprofit, clean transportation consortium that is doing everything it can to advance the clean transportation

industry through information, value added services, assisting in the development of technologies through worker -- through end-user groups and stakeholder groups. We do one-on-one consulting with fleets to advance their policy choices. And we work here in Sacramento very often to get the policy choices advanced and bring new perspective to the policy choices that the state is making.

I am going to talk about biomethane, which is basically a gas that is created from a bio-source. And when I discuss this it is important to remember that biogas or biomethane is the same as natural gas. It's both methane, it has the same chemical contribution.

The difference is that biogas has a renewable source, a bio-source and it has zero or possibly even negative greenhouse gas emissions. If you see the latest ARB in the AB 118 proceedings and also in the Low-Carbon Fuel Standard proceedings, biomethane scored extremely well in terms of greenhouse gases per energy unit.

But the idea is that whether it is a natural gas from a fossil source or from a bio-source it can be injected into the same pipeline

and used for the same end uses, whether it be residential, industrial. And what we are interested in is bringing the transportation component into it. So having biogas as a source of either liquified or compressed natural gas adds to that supply of gas for transportation use.

The process for creating biomethane is the same whether the source is a dairy, a farm, municipal solid waste, a wastewater treatment plant. But basically, whatever the feedstock, it can be digested through an anaerobic digester. Which there are different types. Whether a covered lagoon or a flow plug unit. But this will, through the process can create biogas from this organic waste. A byproduct of this could be bio-fertilizer, which is used often at the dairies and the farms.

That digester gas now can be either used right there at the facility for a combined heat and power unit and produce electricity and heat right there for the facility's use. It can be further upgraded by removing the CO2, nitrogen and some of the other inerts and that upgraded gas can be brought up to pipeline quality.

Basically it meets all of the PUC's

requirements for Rule 21 or Rule 30 so that it can be used in the pipelines. And can be either injected and become a regular pipeline use or it can be used for transportation uses. And as a liquid fuel it can be transported to other stations or it can be compressed and used either at the facility or -- mostly at the facility for the facility's fleet.

We have been asked by Sempra and others to look at some of the biomethane potential in California. We looked at a couple of sources. And there is some disagreement, and this is a good disagreement, between what the potential of biomethane resource is in California. UC Davis did a study a few years ago and I'll show you something that the bioenergy plan from the Energy Commission here did in 2006.

But even though we have differing numbers they are both pretty high. The gross methane potential from bio-sources in California has been estimated by UC Davis at about 125 billion cubic feet per year.

Of that about 23 billion cubic feet seems to be technically feasible, which means that it is economically available. It is easy to

obtain and to upgrade and transport.

From dairy waste alone it has estimated that 14 billion cubic feet is available from bio-sources.

So when we at CALSTART are looking at this from a transportation component, we estimate that using natural gas as a fuel, that can fuel approximately a quarter of a million cars.

The Biomass Fuels Study here at the Energy Commission in 2006 has slightly different numbers but still they were very, they are still significant to show that the potential, when compared against diesel that is used in California, the combination of biomethane and thermal biofuels, which is basically biosyn gas, can basically compete significantly with the diesel that is used. A combined 2.6 billion diesel gallons a year.

We are interested, of course, in looking at the dairies and seeing what they can do and what they can contribute. And using this example. Just in Tulare alone -- Tulare has been called the Saudi Arabia of cows.

(Laughter.)

MR. SOKOLSKY: But you can see from a

transportation component you could fuel just from the dairy biomethane creation in that area, 30,000 cars could be fueled just in the Tulare area. And we did some mapping here with the current stations that are dispensing CNG. And just in those three mile concentric circles there are, there's a lot of biomethane available from dairy sources.

We are currently partnering with other organizations to do the first transportation demonstration project. One of the dairies in the area around Lindsay, which is Hilarides Dairy, is ow running compressed natural gas trucks that are running on compressed biogas.

They are using the dairy itself to run feed and milk product up and down Route 99. They put a lot of miles on. But we are going to test those vehicles to make sure that the emissions and the performance are comparable to other natural gas vehicles and to diesel vehicles to see what the actual benefits are.

But the next step in this project will be moving it -- a similar demonstration at a central facility at Hilmar Cheese near Modesto, which can fuel fleets from many different facilities, both dairies and other truck fleets.

So using the gas as created there it could be a central fueling location for biogas.

There's different benefits from biomethane, biogas. That not only can it be used at a facility that could be off the grid and used to power that facility or even power the trucks for that facility. But it is also, after it is upgraded, can be used for pipeline injection.

PG&E is working in that direction right now with Microgy. It's seven different dairies. They have started construction of their upgrading equipment recently. They should be only hopefully later this year. But PG&E is very interested in this because it helps them meet their Renewable Portfolio Standards. So this is a very good byproduct of the creation of biomethane and biogas.

In addition to dairies the other sources for biomethane are landfills and wastewater treatment plants. Landfills, just to give an idea of how much the potential is. One pound of municipal solid waste in a landfill creates .1 cubic feet of landfill gas right there every year.

We looked at it from a transportation aspect and we saw that some of the projects that

are going on now to do gas upgrading at landfills in California, we could get the equivalent of more than 25,000 gallons of diesel equivalent gallons per day of either CNG or LNG from some of these projects. The most promising one is at Altamont where Waste Management will be putting in a large upgrading facility and fueling their trucks there, which is going to open later this year.

Wastewater treatment plants are also, it's a very, it's a good source for biogas. A hundred gallons of wastewater creates one cubic foot of biogas per day. So just looking nationally there are numerous, 16,000 in the country. And right now no one is really capturing and upgrading this, it is all being used at the facility, if it is being used at all.

I want to just touch briefly on biosyngas. I am not fluent on this issue but Sempra has investigated this and they think this is an area of additional research and consideration. Because the creation of syngas from a bio-source, think there is significant potential as related with the other biomethane creation.

The technology is feasible but still at

an uneconomic phase.

So they recommend that additional research be done on both the technical and economic issues and be incorporated into this Committee's future work.

To give you one idea of what the potential is for biomethane in transportation. In Western Sweden biomethane powers more than one-half of the sources of biogas, of natural gas transportation in Western Sweden. I wish Commissioner Boyd was still here because he could probably do this presentation better because he has seen all this, he knows it firsthand so he is a great resource on this. But the idea that we can learn a lot from what's going on in Sweden in terms of capturing and utilizing biogas is something that has a lot of potential for California.

So finally I just want to highlight a couple of the benefits of using green gas here in California and nationwide.

It's a very strong environmental support for natural gas vehicles by creating that cleaner source of gas and also almost a negative greenhouse gas potential for transportation use.

It's a great transportation transitional feedstock for hydrogen as we become more of a gaseous transportation fuel society. This is a good transitional feedstock.

As I mentioned the environmental benefits of not only natural gas but natural gas hybrids are increased by adding a bio component.

And then we can bring in even more through plug-in hybrids and hybrid EVs with natural gas.

And as I mentioned earlier, the utilities like this because it does meet their portfolio requirements for renewable.

And that's all I have to say, I'll answer any questions. But we think that this is something that should be on the Committee's radar. It deserves additional study in terms of what the actual resource potential is in California from all of these sources. What the effect would be on the pipeline system. Whether the utilities have the capacity to handle a lager amount of gas supply through bio-sources. And that it is something that California should be utilizing more as we have programs like the Low-Carbon Fuel Standard and AB 118.

So thank you for your time. We appreciate the opportunity to speak today.

PRESIDING MEMBER BYRON: That was very good. Thank you, Mr. Sokolsky.

A couple of quick questions. Of course I think the reason probably, as you indicated, as long as it is classified as a renewable fuel the utilities are interested in it. Are you having any difficulty or issues, are there any outstanding issues in being qualified as pipeline quality natural gas?

MR. SOKOLSKY: The technical issues are not there. The technical issues have been solved, mostly overseas. But it is mostly an economic issue now and identifying the proper bio-source and the size of the facility for the operating equipment that is available. So technically it is very easy to do. But it is whether it is economical from a small farm or a small landfill, is that better than a larger one. What are the economics involved with each.

And that is probably the barriers that need to be investigated more than the technical barriers. Because there's plenty of technologies out there to remove mostly CO2 from the raw biogas

to bring it up to pipeline quality and make it acceptable to the utilities for their transmission.

PRESIDING MEMBER BYRON: And of course removing -- my second question has to do with removing greenhouse gases. Are you getting credit when you collect methane from dairy waste as a GHG reduction?

MR. SOKOLSKY: There can be credits collected because the alternative is flaring the gas at the site of the creation of the biogas. So if it can be collected and used and then that credit can be collected either on the utility side or on the transportation side, those credits could be available.

PRESIDING MEMBER BYRON: Are they being, are they being considered under ARB's rulemaking, do you know?

MR. SOKOLSKY: From what I understand they are. I can't answer that precisely. But I understand they are considering that because the air districts are having problems with just the use of biogas in gen sets and combined heat and power at the facilities because they are, have very slightly higher NOx emissions.

PRESIDING MEMBER BYRON: Right.

MR. SOKOLSKY: So they are -- I know at the district level they are very interested in investigating biomethane more closely because they will eliminate that local emissions problem. And it could be more of a greenhouse gas strategy.

PRESIDING MEMBER BYRON: Yes, I have heard about this. Thank you very much.

MR. SOKOLSKY: Thank you.

ADVISOR BROWN: I just wanted to make a couple of comments. And first thank Steve. It's always nice to see you, Steve.

MR. SOKOLSKY: It's nice to be home.

ADVISOR BROWN: On behalf of Commissioner Boyd. This whole issue of biomass, biopower and biomass is a very intense interest area of his. We are actually having a workshop on Tuesday, April 21, on some of these related issues so we get to dig a little bit deeper next week.

I wanted to also comment that on the issue of these dairy digesters. We have been extremely active with Cal-EPA and other parties in trying to get some of these regional collection centers incented.

The issue, and I wanted to get Steve's

take on this. But as I understand it the issue is financial. Some of the projects in the Valley, some of the biogas projects such as the ones that PG&E is pursuing, are having difficulties getting financing right now.

MR. SOKOLSKY: That is exactly right.

ADVISOR BROWN: Along with everybody else, right, because of the economic downturn. And they are really looking for incentives, they are looking for economic stimulus money. And we are going to continue to pursue that. I for one am very appreciative, Steve, of this presentation because I think it solidifies our understanding of some of the issue.

MR. SOKOLSKY: To that point on the economics. We are putting together a biomethane jump-start proposal for some of these stimulus funds. That we are going to bring in companies like Microgy, some of the dairies.

And also I know Paul Relis from CR&R was here earlier today. They are recycling, they do a recycling facility in the Los Angeles area where biogas is created there also.

So there's a lot of sources available. And I think it is just identifying the most

economic source and the most economic upgrading method and location.

ADVISOR BROWN: Right.

MR. SOKOLSKY: That is the key to this and probably the linchpin.

ADVISOR BROWN: Thank you.

MR. SOKOLSKY: Thank you.

MR. SCHREMP: Thank you very much, Steve. And yes, former California Energy Commission employee.

Well I think at this juncture we would like to open it up to any comments or questions anybody in attendance may have here.

And seeing no rush to the podium I'll turn to Nick. Are there anybody with questions online?

MR. JANUSCH: No, unless they want to talk right now.

MR. SCHREMP: Silence I guess answers that question.

So I want to thank all of you for attending today and certainly the presenters for traveling here and putting the time in to put their presentations together and conveying the information. I'll turn the mic back over to

Commissioner Byron.

PRESIDING MEMBER BYRON: Thank you, Gordon.

You know, this was really an extraordinary day and a half. I sometimes use the line that working at the Energy Commission is like drinking from a fire hose. I think this was drinking from a, from a gas pump hose the last day and a half.

(Laughter)

PRESIDING MEMBER BYRON: And of course I don't know of any other state that delves into the details of subject matter like this so it is really a wonderful opportunity. I feel very fortunate to have been on the receiving end of so much good and sometimes troubling and thought-provoking material.

I would like to thank all of our speakers for the extraordinary efforts that they made to bring us up to date and help this Commission move forward in making recommendations in our Integrated Energy Policy Report.

I have taken a lot of notes and I have drafted up some recommendations. I think I should just call them thoughts at this point, that need

further vetting with the staff and my fellow Commissioners on the preparation of the IEPR.

Of course Commissioners Boyd and Douglas are very strong in the transportation fuels and infrastructure area and I will greatly be relying upon them.

But I would like to thank you all again. I would like to thank the staff for pulling together a very extraordinary agenda for us.

We are adjourned.

(Whereupon, at 12:06 p.m., the Joint Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

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

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of May, 2009.

JOHN COTA