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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of,	)
	) Docket No. 17-IEPR-05
	)
2017 Integrated Energy Policy	)
Report (2017 IEPR)	)

IEPR COMMISSIONER WORKSHOP ON

TRANSPORTATION ENERGY SUPPLY TRENDS

AND ASSESSMENT REPORT

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, JULY 6, 2017

11:00 P.M.

Reported By:
Gigi Lastra

APPEARANCES

Commissioners

Robert B. Weisenmiller, Chair

Janea A. Scott, Commissioner

CEC Staff Present

Heather Raitt, Integrated Energy Policy Report (IEPR) Program Manager

Presenters Present

Ryan Eggers, California Energy Commission

Gordon Schremp, California Energy Commission

Dave Hackett, Stillwater Associates

Adrian Tolson, 20/20 Marine Energy

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P R O C E E D I N G S

JULY 6, 2017 1:00 P.M.

MS. RAITT: Hi, for folks on WebEx, do we have Adrian Tolson on?

MR. TOLSON: Hi, good morning.

MS. RAITT: You're on, great. So, we're just going to identify what line you're on, if you can just hold on one moment.

Adrian, are you still there? Okay, we're going to keep unmuting lines.

(Pause)

MS. RAITT: Okay, Adrian, are you there? We're just going through and unmuting each line to figure out which one's yours. Now, are you there?

Okay, we'll try again. Adrian, if you're there, please say something. Are you there?

All right, so I think we're ready to go ahead and get started. So, good afternoon, welcome to today's IEPR Commissioner Workshop on Transportation Energy Supply Trends and Assessment.

I'm Heather Raitt. I'm the Program Manager for the IEPR. Quickly, housekeeping items, if there's an emergency please follow staff to Roosevelt Park, which is across the street from the Energy Commission.

Our meeting is being broadcast over WebEx, so

it's being recorded. We'll have a verbal record, an audio recording posted in about a week and a transcript posted in about a month.

At the end of the day we'll have an opportunity for public comments and we'll limit that to three minutes per person.

And for WebEx folks, you can raise your hand to let our WebEx coordinator know that you'd like to make a comment at the end of the day, and we'll open the lines then.

And for folks, all the materials are available on our website. And also, for folks in the room, they're available at the entrance to the hearing room. And written comments are welcome and due on July 20th.

And with that, I'll turn it over to the Chair.

CHAIR WEISENMILLER: Good afternoon. I'd like to thank everyone for their participation today. Obviously, these fuels really drive our economy. I mean, if you think about the number of cars we have in California, if you think about the average mileage of those cards, and then you come up with some incredible number for the amount of fuel we need.

And, you know, that really is critical. Obviously, trying to transition to zero emission vehicles, alternate fuels but, you know, this is a

critical topic today in terms of really underlying the California economy.

So again, thanks everyone for their participation and interest.

COMMISSIONER SCOTT: Good afternoon and welcome everybody. I echo the Chair's introductory remarks. And I will just note again the importance of kind of looking at the supply trends, which is something we haven't always done. A lot of times we're looking at the demand. So, this is a nice look to see what's going on, on the supply side. So, I'm looking forward to the workshop, very much.

MS. RAITT: Great. So, first is Ryan Eggers, from the Energy Commission, to provide an overview of the workshop.

MR. EGGERS: Thank you. Good afternoon, Commissioners. My name is Ryan Eggers. I'm the Supervisor of the Transportation Fuels Data Unit, and I'm here to give just a quick primer on why we're here today, the reasons for this workshop and what questions we hope to answer by it.

So, the Energy Commission has a 25-year history of publishing refinery production in inventory numbers. We've also been collecting information on the petroleum sector for over 35 years via our Petroleum Industry

Information Reporting Act, also known as PIIRA.

And while staff has been very good at publishing this information on a regular basis, we haven't always been good at explaining the information. So, staff has prepared a report that we do hope to release by the end of the month that will sort of alleviate this deficiency and go into explaining a little bit more of what this information means, and make it more relatable to the common, or the regular citizen in California.

Now, the other reason we're here is historically transportation fuel analysis has emphasized petroleum fuel. But California has a very clear policy focus on diversifying the portfolio fuels offered in the transportation fleet.

And so, as we sort of move into this new, alternative fuel sort of reality, the need to have reporting regulations for alternative and renewable fuels will likely propel a rulemaking in the future.

And we are hoping that workshops, like this, will be able to identify tools, and analysis, and information that's of high value to both the Commissioners, and California as a whole, that we can then part over to the alternative and renewable fuel sector in order to make our rulemaking process a lot more smoothly.

Now, one item that is of high value that has been identified in the past, in the petroleum sector, is our Weekly Fuels Watch. This particular report has been published every week since 1992 and it shows production and inventory numbers for California refineries. And it's very unique in the fact that it is the only State-specific refinery report that we do know of in the nation.

EIA publishes similar information, but it's always by PADD district, which is usually formed of multiple states.

This particular report actually goes a little bit further in the fact that it does have a northern and southern breakout for inventory and production numbers. That you can very much see the spot markets in both Los Angeles and San Francisco trade off this particular information.

Another example would be our Crude by Rail Import Graph. This particular graphic shows import totals from by state and total crude oil imported by rail into California. Also, the area behind is what happened last year.

Another example, we not only publish our own information, but we often do analysis on other agency information, in this case, the Energy Information

Administration information.

Gordon Schremp, our Senior Fuels Analyst, will go into this a little bit more. But Canadian crude oil coming into California is a very contentious issue in the Bay Area right now. And as you can see from this particular chart, in 2016 Canadian oil coming into California only formed about 2 percent of the foreign imported crude into California.

Also, as part of this upcoming report we did additional analysis based on feedback from our Petroleum Market Advisory Committee. One of the things that they did ask for was more information on import and export flows into both Northern California and Southern California to analyze the 2015 Torrance Refinery explosion.

As part of our upcoming report we did do an import/export balance that Gordon will also discuss.

So, here is our workshop agenda and objective. Gordon's going to talk through the first three chapters of our upcoming report, which will discuss crude oil production in California's transportation fuel supply network.

The third chapter will cover renewables and alternative fuels.

Then we're going to have the panel with Dave

Hackett, from Stillwater Associates, discussing new analysis his company has done on refinery operations and closures.

Then we'll be joined by Adrian Tolson, from 20/20 Marine Energy, which will discuss IMO sulfur standards for bunker fuel and what the implications for California refineries are.

I will then return and discuss the fourth chapter in our upcoming report, which will be on the transportation fuel price cases for the 2017 IEPR.

Both the Commissioners got a little bit of a sneak peak of these at the June 20th workshop, with the cost-per-mile calculations. This will go into more detail on how those numbers were actually generated.

But overall we do want, in everybody's mind, both the public and the Commissioners; we would like to identify what sort of information and assessments that should be replicated once we start collecting information on alternative and renewable fuels in a much more codified manner.

If there's any questions?

All right, I'd like to pass the podium to Gordon Schremp.

MR. SCHREMP: Good afternoon Chair, Commissioner, and interested stakeholders in the room

and online. Welcome to yet another IEPR workshop, chock full of interesting information. I'll certainly cover a lot of information. As Ryan mentioned, we're going to have a rather lengthy staff report coming out at the end of the month.

This is to take a lot of that information, distill it down so -- some higher level, but in some cases a lot of detail.

So, I think something to keep in mind that the IEPR process, as some of you may already know, the intention is to get a lot of information into the Energy Commission through our workshop process, comments you make here or comments you make afterwards, because all that information is important to the Energy Commission to sift through and bring up to the surface some of the more important issues, as new policy and existing policy's examined for energy.

So, think about, as we walk through the information we're presenting, from the perspective of are there some things that you think are pretty important, how come we're not covering them in this particular area of topics, but should be covered. But your opportunity is to provide comments to the docket. So, we encourage those, certainly.

So, I'll start off with crude oil. I'll have,

actually, four sessions of slides to go through before I turn it over to our guest panel speakers. And if the dais has any questions, at any time, please feel free to interrupt me at any time. And I'll pause at the end of each section to see if there are any additional questions.

So, crude oil, I'll cover basically California, U.S., and global. And then, we'll talk about a couple of key areas of interest that we've been following over the years, and that's oil exports and crude by rail, that Ryan already mentioned.

So, has crude oil been around for a while? Oh, certainly, it has. Over 150 years of production here in California, certainly peaked in 1985 and has been on the decline pretty much, almost unabated, ever since.

And now, in 2016, oil prices stand at where it was in the Great Depression of 1934.

So, if you took all of the crude oil that we've produced, over 150 years, it's still not quite a year's worth of production for the planet. So, producing a long time, yes, but relatively speaking a smaller portion of oil.

So, where does all this oil come from? So, that chart is the green, the bottom, so right, currently it's 34 percent of all crude oil the refiners in California

use. It's declined, of course, with California's declined. But not to worry, the refiners are able to substitute for crude oil decline losses in California and bring it in from elsewhere.

Alaska has been just like California its production, too, declining over time and, as a consequence, also had to replace Alaska crude oil sources, which are only 11 percent in California.

So now, foreign, of which Ryan showed you one of those charts, almost 55 percent of our total and that's expected to go up over time.

It makes the final point in this slide, if you look at the very top part of the stack areas, it was higher in the early 1990s and actually has declined a little over time, as some of the refineries in California have shut down, actually.

So, this looks at the foreign and the Alaska piece as sort of the water-borne crude oil. Basically, almost all of it comes in over the water. A small amount of crude by rail is the very top sliver. That small, little light green area.

But this just goes to show the diversity of crude oil is growing. And in some cases additional supply is coming online, but it's very diverse. And that's what the refiners want is the ability to pull and

select crude oil that meets qualities that they're looking for to process in their refinery.

So, this diversification is expected to continue over time. In some cases you'll see something like, for example Mexican crude was higher at one point but they, too, have had production losses, so we are seeing less coming in from Mexico.

Ryan already showed you this chart. But I think one of the takeaways is 45 percent of the totals are from North and South America. So, whatever is close is usually what comes to the refining centers because the economics of transportation are cheaper than bringing it across the Pacific.

So, the U.S., there has been a renaissance of crude oil production in the United States. That is because of development of tight oil or shale oil, extended drilling, multiple drill bores from an existing pad. Drill efficiency has gone up tremendously. Hydraulic fracturing has been deployed in a large manner in many basins in the United States, and in some other foreign countries.

But this exploitation of tight oil formation has allowed this light oil to significantly increase.

And these three lines are three regions or basins of crude oil production in the United States.

And important to note the Permian, or the green one, in West Texas, is actually the second largest producing field in the world. Only second to Galbar, in Saudi Arabia, which is a super, giant field.

There was another field in Venezuela, in production history that was a little bit hotter than this, but right now this is the number two in the world and still expected to continue increasing in output. But no, it won't get past -- I think the Saudi field is over 5 million barrels a day, so no one's predicting that.

So, you take those basins and there's been a resurgence or production that almost set the record, set back in 1970 for crude oil production. EIA is forecasting that next year 10 million barrels a day production will be exceeded and the record will be broker. And that's I think at current prices, with some moderate price increase.

So, where is all the incremental oil coming from on a state basis? Texas. Those are those two basins are in Texas Permian and Eagle Ford, so over 2 million barrels a day from January 2010 to January 2017, a seven-year period.

And North Dakota, another big location. And the rest of the states, in fact New Mexico and Oklahoma are

starting to show significant increases as well.

But look at California and Alaska, down. Over that seven year comparative they're down and they're down about the same amount. So, the resurgence is not occurring in California. We do have tight oil formation in the reserves, so to speak. But they're not as economically desirable as the other parts of the country because of the much more complex geology in California. So, that's why we haven't seen a comparative rebound in crude oil production in California, because of the economics.

So, with more oil increasing, less imports needed. And that's the decline from 10 million barrels a day of imported oil to seven, so a rather significant decrease.

Now, back on the plus side. Only because of the temporary decline in crude oil production that has now started back up in the United States, so we expect to see foreign imports of crude oil into the United States start to decline once again.

Now, the production can only occur if you drill holes in the ground in those basins and so, that's what happened. The drill rigs that you see by this red line, their weekly data, a tremendous increase up to the peak, and 1,601 deployed, just looking for oil. And a

significant drop off with what? The collapse in prices that Ryan will cover a little bit later today.

And so, those decline, prices rebound a little bit, but the drilling activity picked back up even with somewhat flat prices. This is because the least cost producing operators have some of the lowest costs and are able to operate in a much lower price environment, to the dismay of OPEC members who thought if the marked was flooded, and they kept the market share that lower prices would put most of this out of business. That didn't happen.

There are two parts in producing oil from tight oil formations. You drill the holes into the reserve and then you're ready to hydraulically fracture those completed bore holes. And so, that's the second step. And so, what's been going on is the second step hasn't yet been completed on a growing number of these wells, now at a record 5,000.

So, this backlog, duck backlog as they call it, or drilled and uncompleted wells is significant. And the important point of this is that that allows someone to go in and hydraulically fracture completed wells within a couple of days. And as soon as you do that, production is occurring.

So this is sort of, okay, I can open up the taps

a little bit more. If prices actually do rebound, I'll go ahead and do that. So, this is what's been going on in the oil markets now, with OPEC with a production cut in February because of this backlog.

So, on planet earth where is the oil coming from over the last eight years? That would be from the United States. That is the stark contrast to other areas, such as Iraq, over 2 million barrels a day from 2008 to 2016, and the Saudi Arabia I think is number two there.

So, you take the U.S., it's grand on the next three largest incremental producers, so rather significant.

Libya, in this slide, 2016 compared to 2008 is down, and that's really down more as a consequence of conflict ongoing in Libya preventing it, at least through 2016 data. But lo and behold, in 2017 Libyan production, with agreements to warring parties, has actually gone up to I think near 800,000 barrels a day, very significant. OPEC's not very pleased with that because that's putting a damper on their OPEC cuts.

So, OPEC is cutting production. Why? They want to try to rebalance the global glut of oil. So, anywhere on this busy chart you have two components, supply in blue, demand, global demand in orange. Where

blue is higher than orange that means too much supply. And so, that's what those numbers are. So, any numbers that are greater than zero, that's knowns of barrels per day. And so you saw at the worst 2 million barrels a day, in the first quarter of 2015, were being added to global inventories. So, lots of oil going into storage everywhere, the U.S., Europe, China, and Southeast Asia. And so that's the glut that OPEC is trying to trim. But they're going to have to not only get below zero, they're going to have to go negative and stay that way for many quarters. So, that has yet to occur.

Even the OPEC cuts that they have, which are 1.8 million barrels a day, from an October baseline, are being held, and this includes Russia as well is cooperating. And they've decided to actually continue that through the first quarter of 2018 and will meet in November to see if they want to do that even longer. So, this is an ongoing issue.

So, as a consequence of lots of oil still, the glut hasn't really gone away. Oil prices have been kind of stabilized and dropping lower, and lower, and lower.

And I think yesterday the price of oil of Brent, which is the international benchmark crude, was $47.79, and is about the same exact price it was a year ago.

So, all that effort by OPEC and what do you

have? Prices are still where they are, not rising, which they want.

So, the last couple slides on this topic, I want to talk about oil exports. Yes, this country had export restrictions for decades, out of the Arab oil embargo. And you could export oil to Canada, but you were doing that because you were bringing a commensurate volume back. So, it make sort of sense in the logistics.

So, you could also export from California, heavy oil, 25,000 barrels a day, but no one was doing that because of the economics and the infrastructure, frankly, weren't there to do that.

That all changed January 2016, the restrictions were lifted and, lo and behold, go to the right of the dotted vertical line and you see, well, there's a whole bunch more colors going up compared to the Canadian ones. That's right. So, exports were over a million barrels a day in February, at least the data in this chart and it's the most recent data available. April, it's still a million barrels a day.

There's infrastructure going in in Corpus Christi, other Gulf Coast locations, to increase the capacity to export oil. So, shale producers can bring more online and they now have a growing market for exporting crude oil. So, there's not a restriction to

do that because of that being lifted.

The second issue that we've covered extensively, we had an IEPR process on this to look at crude by rail as it was increasing dramatically. Lots of concerns issued by many stakeholders, as Ryan pointed out. So, that was growing because there was a glut of oil trapped in these newer producing regions and not enough pipeline capacity to ship it to the refining customers. All those pipelines were filled up.

And so if you wanted to move it, you either trucked it, which having it trucked long distance is very expensive, or you moved it by rail. And so, crude by rail came about because the producers had to discount their oil enough to make the more expensive rail tariff work.

Well, pipeline projects continued. Pipeline projects completed. The pipeline take away capacity went up and now I don't need to use more expensive rail, I use less expensive pipeline tariff. And that's why crude by rail volumes have dropped to their lowest point in many years, 3.3 percent as to this data point in March 2017.

California is in similar shape. It went up because the discounts were there, you could bring crude by rail in and it dropped off when discounts went away.

And in 2016, crude by rail represented less than the 0.2 percent of total crude oil supply for California refiners, a very small percentage.

Those are all the slides I have on crude oil. If you have any questions, I'd be happy to answer them at this time.

COMMISSIONER SCOTT: I have a quick question for you.

MR. SCHREMP: Okay.

COMMISSIONER SCOTT: On the global crude supply imbalance, you mentioned that OPEC is trying -- which is slide 17 -- was trying to rebalance the global supply of oil, but that it could take many years in the negative numbers to do that. Do you have a sense of how long that time frame could be?

MR. SCHREMP: I think it's more of several quarters.

COMMISSIONER SCOTT: Oh, several quarters.

MR. SCHREMP: Yeah, several quarters consecutively. So, part of the issue with a lot of information in the energy arena is it's like all in your rearview mirror.

COMMISSIONER SCOTT: Right.

MR. SCHREMP: It's like this happened in May, aren't we in July? Gordon, you have first quarter of

2017, what, you have old information here? Well, the data hasn't become available, yet.

And so, it takes a lot for verifiable information to come in and so the industry can look and go, ah, it's working. And so, there's a bit of a time lag. So, what the market participants want to see is negative numbers, and decent negative numbers and lasting. So, that's one thing they want to see in this kind of data.

They also want to see, month-to-month what's the inventory of crude oil in the United States, European countries, Southeast Asia, and are those showing consistent declines? So then it's, okay, well, that's working,.

And so, it's just those kind of indicators can get the market participants to think that the prices of crude oil will rebound and have upward pressure and can start in their purchasing decisions for future contracts, we'll buy in that manner.

So, it takes usually a couple of months of sustained data to get most of the market momentum going to demonstrate that, but it hasn't happened, yet.

So, I think what we're seeing first, because the inventory data certainly is more near term, and we are seeing a decline in the U.S. and some of the other

countries, and other people are talking about the glut of refined product inventory. So what that means is, well, I don't have to produce as much gasoline for the summer because I have so much more inventory. So, that could be another inventory that I won't demand as much crude oil.

So, there is different statistics that people look at, but it does take some months for the data to come through.

But yeah, I would say multiple quarters of the demonstration of yes, it's working, and the glut's going down. But once again, the shale industry can respond to prices rising and go ahead and start completing more of those uncompleted wells.

COMMISSIONER SCOTT: Thanks.

MR. SCHREMP: Sure.

Thank you, Heather. I'll now transition to a discussion of sort of where is the fuel coming from, what is that fuel consumption numbers and trends look like, and close it out with talking about the final step that we're all familiar with, and that's retail sales and operations.

So, a little perspective, I showed you the historical crude oil prices slide. So, we'll do that with refining, as well. Refining goes back as far as

crude oil production, certainly.

And this is one of the more sophisticated refineries, one of the early ones, 1877. It doesn't look like much compared to today and very small.

And then if you look at, well, what's happened to refining in California, specifically, or say a longer period of time? So, looking at 1982, some of the earliest PIIRA data collected by the California Energy Commission, 40 operating refineries, 2.6 billion barrels a day processing capacity, but they only operated at 62 percent utilization. Not full throttle. And they were making almost a million barrels a day of gasoline, and you see a quarter million of distillates, and 184.

So, look at the 2016 data and you see, oh, only 15 operating refineries, a lot smaller crude oil processing capacity, much higher utilization and producing even more fuel than they did with, you know, the 62 percent fewer facilities.

So, this just tells you the remaining facilities are larger, you know, economies of scale, and they are more sophisticating. Additional types of process equipment has been added to allow refiners to take some, you know, less economic material, like residual fuel oil, and cook it even more in something like a coker, and producing even more gasoline and diesel.

So, a lot has changed; so fewer facilities, but more production and higher utilization rates. So, these generic refinery, very simplistic, and as Dave Hackett has pointed out, Gordon, where are the units that produce gasoline? Well, I guess you see them now (indiscernible) -- yeah, yeah, yeah. Yeah, details, I understand that. Thank you, Dave.

This is intended to show that refiners depend on a lot of outside utilities. They need water. They need hydrogen. They need acid. There's all kinds of things they depend on and so, all of that is necessary for refiners to continue operation.

And, of course, storage capacity is finite. And what do I mean by that is you can't just keep producing and putting into storage if you have a problem, say, in the pipeline distribution system because you run out of space. So, that's just an example.

So, this is sort of the nerve center, they're operating all the time. Like I said, there's 15 producing, operating now, and 13 of them produce California spec fuels, gasoline, and diesel.

The crude oil that you saw earlier, this just breaks out the exact numbers and shows you that rail truck is very, very small, 3,000 barrels a day, compared to these other sources.

So, where are they? Well, if they're receiving a lot of crude oil by water, they want to be close to the water. And so, certainly, in Northern California they are, they're located right next to the water. They all have marine terminals and that allows them to import a significant amount of crude oil, about two-thirds over the water.

Southern California, a little bit different. You see the numbers are located inland, further away. That's because there were many oil production fields further inland and they were pretty close to those back in the day, as they say. But they all have connectivity to the water. And so, they can get that.

But the important distinction is that these companies do not own and operate their marine terminals like they do in Northern California. And that's the Cities of Los Angeles and Long Beach do and so, they're at least -- you know, they're the landlords. And so, we've seen over time some pressure can be brought to bear by those cities on those lease holders at times, to try to pressure them to either get our early, or get out when their lease runs out.

So, that's certainly an issue that's periodically come up before the Energy Commission as something that could create problems for bringing enough

oil to operate the refineries. But in this day and age, now, actually bringing enough renewable components to help with like the Low Carbon Fuel Standard, like bringing in Brazilian ethanol, bringing in renewable diesel from Singapore, and biodiesel from Southeast Asia.

So, the refineries produce more than gasoline and diesel, but they're gasoline-producing machines because they produce what their clients want. That's the local demand. So, gasoline is about four times the amount of demand as diesel fuel, but you're seeing almost a double the gasoline, or half of the pie is gasoline, and a quarter is diesel, and almost that is jet fuel. But there is a significant portion of other parts of pieces coming out.

Asphalt and road oil is very small, but very important. And some other things, like distilled gas, is something that when you cook the crude oil it's a higher carbon gas form that you can burn. And so, it's used as a fuel to supplement natural gas being purchased by the refiners to create process steam, as well as hydrogen.

So, we use a lot of gasoline, over 15 and a half billion gallons in 2016. And you see that the chart is composed of two pieces, the gasoline or blue part, and

the green or ethanol part. The total, combined, was at a peak decline of about 7 percent and has now gone back up. Sorry, 9 percent and has recovered about a 7 percent increase. So, that's the rebound of gasoline demand because the economy recovered from the Great Recession. The population has continued to grow.

So, ethanol use has gone up significantly, about 4 percent of the gallon of gasoline contained ethanol, and now it's about 10 percent. So, that's gone up because of the Renewable Fuel Standard, primarily in the United States and in California.

Diesel, a somewhat similar pattern, it peaked, it declined with the recession, the goods movement went down, but now recovery has occurred. Not all the way yet, still short, just like that of gasoline. Not quite an all-time record. But you're seeing a more significant push for renewable fuels and this is much more of a direct impact because of the Low Carbon Fuel Standard, rather than the Renewable Fuel Standard, or a Federal program because you want to use renewable diesel, and specific types of biodiesel that have lower carbon intensity. And I'll talk about that in just a little bit.

Commercial jet fuel, a similar pattern, down with the recession and now back up with economic

recovery, but it has actually recovered more than the other fuels. In fact, it has gone to a record level. And anybody who has flown a plane could probably attest to, yeah, the airports are pretty busy and the planes are pretty crowded. So, this is expected to continue rising.

So, there are other types of transportation fuels, certainly, and we're calling this the gaseous fuel consumption, liquefied petroleum gas, propane, LPG, LNG is liquefied nature gas, CNG, compressed natural gas, and hydrogen. So, you see basically all, expect for propane at the very end, I don't know what's going on, we're calling this preliminary number something strange in the propane data, but we'll hope to have that cleared up by the time the report comes out.

But the others are rising and especially when you look at hydrogen. On the far right, a very modest amount in 2003 and then up to its record amount in California so far, in 2016, and that's expected to rise. There's lots of investment going on. The Commission is a large part of infrastructure development for hydrogen. There are more original engine manufacturers coming out with hydrogen vehicles. So, this is something that's expected to continue rising.

COMMISSIONER SCOTT: Now, a quick question on

that. So, on the hydrogen piece, is that all going into kind of the passenger car sector or is some of that going into other light duty vehicles, like forklifts, and things like that?

MR. SCHREMP: I think there is some going into -- there is some transit using hydrogen, and there is some other non-light duty, but I don't have the exact breakdown. But we can certainly, you know, make sure we address that.

COMMISSIONER SCOTT: I just wondered, thanks.

MR. SCHREMP: Yeah. So, the importance of natural gas is bifurcated. It's not just oh, yeah, it's natural gas, natural gas is good and we'll see more of it. Well, it's not necessarily so in transportation.

In the Low Carbon Fuel Standard, the carbon intensity of traditional natural gas coming out of the ground has a much higher carbon intensity compared to biomethane. Capturing methane sources, so either being burned or going to the atmosphere, it's a greenhouse gas that is much more of a global climate changes, I know, 17 plus times greater.

So, biomethane is something that is captured in more and more projects, and being consumed as a transportation fuel. So, this is generating, actually, significant credits and the credits are growing. And

so, over time we expect to see more of that.

And if you look at the top part, the very far right-hand bar is for all of 2016, and you're seeing renewable diesel was a significant chunk of total credits, so a very important fuel for the Low Carbon Fuel Standard and biodiesel.

So, those two, together, if you just sort of look at that, that's a significant percentage yet is only 16 percent of the diesel fuel volume which is, you know, 4 percent of gasoline diesel. It's a very small amount of total volume, very large amount of carbon credits. And so, we expect that to continue moving forward.

So, electricity, everyone's heard about Tesla, more makes and models. Tesla has another version coming out I think next month. And so that is driving demand growth in electricity in the light duty.

As Commissioner Scott mentioned, you know, what portion is light in hydrogen? Well, in the electricity that portion is green and that's the one that's growing. Not the others. Rail transit, you know, you're sure your rail is fixed and the Bay Area Rapid Transit isn't expanding, really, and so that really isn't changing. And so, it's really the light duty, and that's plug-in hybrid electrics and it's full battery-electric vehicles

being charged in the public, of which the Commission is helping support a lot of that expansion capability. As well as in the home, people in their home or whether they live, an apartment complex, have charging when they're asleep. So, that's expected to continue growing.

Certainly as electric vehicles, more of them are purchased by consumers and more of them become available, as well as, potentially, in heavy duty application and medium duty.

So, we'll talk about sort of all these fuels, now how do they get to where they need to go? So, this map is looking at the Western States. Ryan mentioned earlier EIA looks at regions of the country, so this is PADD 5, or Petroleum Administration Defense District 5. It includes California in this.

But the takeaway is this region is isolated. We get a little bit coming out of West Texas in the bottom there, into Arizona, and a little bit coming out of Utah. But, really, self-sufficient, we produce as much as we sort of consume, some foreign stuff comes in, some foreign stuff goes out. But it's sort of an isolated region in and of itself.

And so, California in particular, a balanced market, produce as much as we can consume, normally.

So, when we have an upset, what happens? Well, we'll bring more in.

But if you go back to the other slide it's like, well, what pipelines are going to -- there aren't any. Well, so, if you're not going to bring it in by pipeline, then you're going to have to bring it in by marine vessel. So, that's weeks away, weeks to months away.

And so that's why, when we do have significant unplanned outages, like the exposure of the ESP at the Torrance Refinery, in 2015, there can be a delay to get resupply and we can see a significant price increase, and that's what happens.

But that's markedly different than other regions. The bottom part of the U.S., the Gulf Coast States are PADD 3, they're huge net exporting. What do I mean by that? They produce 7.5 million barrels a day; they exported two-thirds of that. It went away.

So, you can imagine, if they have a refinery problem the market goes, yeah, whatever. If they have a hurricane that shuts the refineries down temporarily, no damage, the pipelines feeding, where all of that goes, they can have a problem and they have had a problem in the past. And so, but for that region, a tremendous net exporter.

On the opposite side of that net importing region, the East Coast, all the way down to Florida, Florida no refineries, all imported. Mostly by marine, a little bit of trucking comes in there. And so, when something happens to a refinery in those places the market goes, yeah, whatever, no big deal, bring in a couple more ships. There's a huge infrastructure for importation of both finished, refined products, as well as ingredients to create gasoline. And so, there's lots of different players, lots of different storage tanks and import facilities.

So, I'm going to look at California in two pieces, Northern California and Southern, and they're separate. They're not connected. You see this map of the Kinder Morgan system, the Northern System that goes down to Bakersfield, there's no pipeline going down to Southern California, there's no pipeline coming from Southern California. So, we can't resupply each other that way. So, these two systems are sort of separate from one another.

So, Kinder Morgan is a common carrier company. they don't own any refined products, they just provide logistics. There are other companies that do own refined products, and they do have some of their own proprietary systems. Chevron is probably the biggest

one that has more of their own pipeline systems they control compared to the other refining companies.

But they'll have other, smaller segments that may go to their own dedicated distribution terminal, attached to their refinery, things of that nature.

So, Ryan and his team put together, which I think are some really good information that, you know, we haven't shown before or developed. I know there's a lot of stuff here, so I'll just spend a couple minutes on it.

The red line is zero. So, anything above the red line is a type of import that's come in. And so, it has color coding, so the green is what we call intrastate and that's coming from another state.

Well, Oregon has no refineries so it's coming from Washington. So, that's the volume of gasoline only coming down, and you see that's pretty steady. Maybe it went down a little bit.

And then you'll see some south to north transfer, sort of the candy cane striped. And you see, on occasion, some of that comes from Southern California. So, what is that? I had a refinery problem in Northern California, help me, help me, send some supply, if you have some extra send. That's what happens. So, it's infrequent at best.

And four, in the blue, coming in very infrequent. Why? Because Northern California's typically long on gasoline, produce more than we need locally, and so foreign imports aren't really competitive coming into this market. Not necessary.

So, what's been changing, if you look at the trend, the purpose on the bottom, where we look at all of the exports, that's been growing, and so those are foreign exports. And this is a phenomenon that's occurring for all of the United States. Exports of gasoline, diesel, jet fuel went to record numbers in 2016, for the U.S. as a whole, and the West Coast. So, this is expected to continue rising.

Some of the other exports, the pink color was an interstate export. So, where was that going? That was basically going to Oregon. Well, is Oregon using a lot less fuel, gasoline? No, they're still using lots of gasoline, but it's being supplied from Washington, a more economic source of supply into the Portland market, and bringing it into that pipeline system. So, that's been going away.

And then you see north to south transfers, we sent a lot of gasoline south because, like I said, we produce more than we need and Southern California doesn't produce as much as it needs. And so, this is a

normal transfer that occurs. And the bottom line, the brown, is what goes in pipeline to Reno. And as you can tell, the thickness of that line is pretty steady because of the demand up there and the capacity to pipeline.

So, those are all the elements. But as you can see, it looks like exports on the bottom have gotten squeezed down a little bit more, and imports a little bit, so we're getting closer and closer, almost to a sort of a zero balance inflow and outflow.

So, for infrastructure analysis purposes, this means that the existing plumbing is not being used as much, so there's a little bit more room to bring stuff in or export stuff out.

Diesel fuel is a little bit different animal. You see, wow, there's hardly anything above the red line. That means we're hardly importing anything. We don't need to because we're even more, in Northern California, long on diesel, than we are gasoline.

And the purple is very large, the large part is foreign export diesel, and that's going down to Mexico, Central America, and South America, to Chile.

And the brown you see is similar in size to what was going to, for gasoline, to Reno. So, we're seeing a little bit more, you know, that's going out and nothing

changing much expect when we have refinery problems.

The foreign import, the blue on the top, or the candy cane, again, if it's from Southern California, so usually tied to refinery problems.

So, we'll shift gears and look at the southern part of the State. So, on the left-hand size of this graphic you'll see a red line, down by the Salton Sea, and it goes all the way into Arizona. And you see some light green lines going into Las Vegas.

Well, Kinder Morgan operates all of that, even though the light green is called Calumet. And we supply about 85 percent of Nevada and about, you know, 45 percent of Arizona fuels because they're getting fuel from -- some from New Mexico, but mainly from West Texas.

And why Nevada isn't a hundred percent is because there's a new player into that market. And it's the new pipeline system from the refineries in Utah and it goes all the way down to North Vegas. And so, that's been in operation for four or five years, now, and it does have a larger capacity. It's not operated at that level, but it can be expanded to that capacity. But you need supply to stick into that pipeline in Utah, and there are times of the year where the Utah refineries don't have that kind of spare production capacity.

There are some capacity expansion projects underway at Utah refineries, and they usually have plenty of additional gasoline to send. When? The wintertime when we really don't need it as much because our demand is down and California refineries can produce more.

So, gasoline flows, the size above the red line and below the red line, and on those, the peaks are much bigger. So, there's a little bit more of variability. But the same phenomenon, it's all narrowing down a bit more.

But you can see, just one quick takeaway, look at below the red line, that dark brown, the pipeline exports, huge. They're just absolutely huge. That's what this system is supplying. It goes into Arizona and New Mexico. And we did have some foreign exports of gasoline but, really, that's coming out of Northern California. Why? Southern California is short. So, you're not going to send out and get more back in.

And you do see those little candy cane exports, those are the red things below the red line. And we do start to see some foreign imports coming in. And most recently, in the 2015 data, that's because of the ExxonMobil explosion. We needed lots of additional gasoline, from lots of different places, and a lot of

that was foreign source gasoline.

So, once again coming closer together, and now the market is sort of in a net export mode when you include pipelines, a significant one over the last several months.

Diesel fuel similar, but once again the pipeline exports are a huge part of total exports. That's the market that's being served. There are three times the Northern California volumes for diesel fuel.

And very little imports coming in foreign, the blue lines, and very little foreign exports going out for diesel fuel, as well. So, this is really domestic.

So, any questions on any of those before I finish up with some retail?

COMMISSIONER SCOTT: No, excellent explanations.

MR. SCHREMP: Okay. So, I have some -- you know, at your next social gathering, family gathering, some fun facts here, just like some historical perspective is useful.

So, the first fueling station, I mean gasoline's been around for longer than that, but you had to go pick it up in small cans. And so, 1905 or 1907, there's some dispute of when the first serve filling station is. But in 1908, 300,000 vehicles nationwide, but the first drive-in, they go there and drive, and they stop, that

wasn't until 1913. In Pennsylvania they had, yes, roadmaps, and we all know what those are. And the first credit cards were pre-depression, you know, 1924, and then the first convenience store. So, Southland Ice Company, they had ice and so they were keeping other things fresh, vegetables, milk. And so, they said, hey, yeah, you can buy some of that, too. So, they did. And so, they stated doing more of that. And they go, well, if we're going to have more than a couple of stores we have to have a name besides the Southland Ice Company. So, they go, yeah, okay when do we open? Oh, we open at 7:00 a.m. When do you close? 11:00 p.m. Oh, we'll call ourselves 7-11. And that's 7-11, that's where 7-11 came from, 1927, Dallas, Texas.

First self-serve, I mean there was always an attendant, but that wasn't until 1947 where you can go in and actually operate your pump. But even when you did that, there was still an attendant that came out and reset it to zero it back out for the next customer.

So, that wasn't until 1964 where you could go in and that didn't have to be done anymore. You picked up your fuel, no one needed to be around and so that was in Colorado.

And then, not until 1986, believe it or not, is when you could first take your credit card, stick in the

dispenser and pay, and not go inside to pay and most of you didn't want to, and left. You couldn't do that before then. And it was only a couple of percent in that year, but now it's everywhere.

I think I told my wife that and she goes, 1986, are you sure? And I go, yeah, I'm pretty sure. But it's ubiquitous, it's everywhere. And so, that technology allows very convenience to customers.

COMMISSIONER SCOTT: Yeah, we're going to be all the rage at the next social gathering.

MR. SCHREMP: Exactly. So, convenience stores and you go, Gordon, why do you have convenience stores in here? Well, they sell 80 percent of the fuel in the United States, so they're a significant store. And if you build a place that dispenses fuel today, you'll just do that and you're going to have a convenience store attached to it. That's where you make, actually, most of your profits. Pre-tax profits is at the non-fuel sales. We'll talk about that in just a minute here.

So, there's a lot of them, but the takeaway here is that 59 percent sole owner. One person owns just one store and that's all I have, I don't have a whole chain, I'm just me and one store. So, that's quite different.

You know, the vertically integrated companies owning and operating their store .25 percent. So,

that's become very, very small.

You see the flag stations, Chevron stations, everywhere. Well, they're not all owned and operated, they're leased. They're leases. They're like the franchisees at KFC, McDonald's, but they don't own and operate.

So, pre-tax profits have things that have been good recently. Right, things have been record good recently for convenience store operators. Pre-tax profits have jumped 42 percent in the last three years of data, a significant climb from sort of some of the doldrums and the low points, especially after the recession. So, this type of business activity is becoming more profitable.

And they have revenue from two primary sources. I sell fuel, gas and diesel, and I sell things inside the store.

And so the red are the revenue from inside the store, the blue is the fuel. So, you're looking at that and you go, wow, most of the revenue is from selling fuel. That's right, but not most of the profit. Most of the pre-tax profit are the red numbers.

And so, the blue line is what percent of total pre-tax profits they're coming from, fuel sales, now it's 40 percent. I mean at the low point it was like 27

percent, back there in 2010. So, that's been rising, the amount of fuel, so they're able to command a higher margin, sustained margin on fuel. And so, the profitability of selling fuel has actually increased significantly, which is interesting why that is. I mean, I think Dave Hackett has a theory about that he might want to share, but it's something we're going to be looking more into.

So, Ryan's group does an amazing job. There's an annual survey of every single retail station in California. And so, they do their level best to get people to fill that in. It's a mandatory requirement but, you know, some people if they go out of business, new ones come in. People, you know, they don't know we exist, we don't know that their station exists. But I think this year is a record percentage of compliance, if I'm not mistaken, from what Ryan told me.

And, we've gone to a fully automated or, excuse me, a web-based data submittal system. So, the customers can -- the reporting entities can go online and report directly. So, that's been a great achievement that the office has done to be able to do that.

So, we get a lot of data from the survey. The number of underground storage tanks, different kinds of

fuel they sell, what type of -- if they're a convenience store or truck stop. And so, it's a wealth of information and we use this in a lot of different ways. And the 2016 data should be available soon.

But one of the ways we're using this is looking at a through put at certain locations. And we're looking at this as part of our emergency fuel planning activity to see where maybe some locations would be ideal to help first responders, you know, source fuel after a catastrophic earthquake.

So, the data is broken down, and you can break it down by county and L.A., the biggest population, of course, the greatest fuel sales. There are two colors here, there's a dark color and a lighter color. That just is the projected total amount of fuel we think is sold there because we don't have 100 percent compliance, yet, of all the respondents. So, we're sort of projecting the rest. But the lion's share is there.

And this is what they sell per month by location. And so, once again, if you're in an urban area you're very busy, more fuel sales. Duh. If you're rural, hardly anyone comes in there, less. And so, we see that in the data. The average is about 133,000 gallons per month, per location.

Diesel fuel, it's a lot less, it's one quarter.

And besides, diesel is sort of two parts. There's retail sales that are taxable and then there are nontaxable diesel sales which are about, you know, one quarter to 28 percent of total sales that really won't be captured in this data.

But what's different here is look at the counties that are total, and they're some non-urban counties. And that's because this is agricultural activity diesel. And especially if you look at specific sales for location, Tehama County, Merced, Madera, San Joaquin, these are all big AG counties. They have much higher sales per individual location compared to the urban areas, so it's the opposite.

So, back to hypermarts, hypermarketers or hypermarts are, you know, we all know Costco, Sam's Club, Safeway, and in the United States there are a growing number of them, and here's sort of the breakdown.

And what's important to know is that in the United States these locations sell twice the volume of fuel for a typical service station in the U.S.

In California it's much higher. It's almost five and a half times more fuel is sold by a typical hypermarts store compared to the other stations. And so, this takes each of the counties and this takes the

averages of all the hypermarts, the light purple, and looks at the dark purple, the average of all the other stores. And you see a tremendous difference in monthly sales.

And so, once again we look at this as a reason to say, oh, well if there's a big earthquake, for example in the Greater San Francisco Bay Area, these locations will have larger underground storage tanks, more fuel trapped underground that could be used by first responders in the area. And so, that's one of the areas that we're looking at to make progress, to see if arrangements can be made that that fuel can be available for first responders after a catastrophic earthquake, as an example.

The final slide here is just, you know, we all know we spend a lot for fuel. But actually, we think we do, but relatively speaking as a percent of income it is a smaller amount, and it's actually been declining. But it's been declining why? Because crude oil prices have been falling and staying relatively pretty low.

So, that's my last slide in this section, any questions? So, some more things you can look at, at your leisure. And, yes, tell me if you find a service station that has three gentlemen standing there, ready to wash your window and check your tire pressure

anymore. No, you don't.

Okay, well, now that I'm on that, the bottom right-hand corner you see horses pulling a wagon. That's a tank wagon. So, fuel delivered to service stations in their contract is what kind of a wholesale transaction? It's called a dealer tank wagon transaction, a delivered, and there is a tank wagon. They don't use those anymore.

Okay, renewable and alternative fuels. We collect a lot of information on this, including from ethanol and biodiesel producers, and renewable fuel producers, like refiners. There's also lots of pricing and consumption data.

So, I'll cover the basic of ethanol, biodiesel, and then talk about some other emerging fuels, besides those.

So, lots of ethanol is produced in the United States, and for a couple of different reasons. A record amount, actually last year, 15.3 billion gallons, so that's rather significant, and it's been growing for two reasons. One is methyl tertiary butyl ether was used in gasoline, high octane, pretty good blending component.

However, concerns about contamination of groundwater resulted ultimately in that being phased out, initially in states like California, then the rest

of the country.

So, they needed something to replace the MTBE that had octane and meet the oxygen requirement in gasoline. And then the Renewable Fuel Standard came in and said you had to have oxygen, you had to have more of it. And so, ethanol was what was needed.

And now, more recently, in the Renewable Fuel Standard Part 2, more ethanol and so, that's what's driven all of this up significantly from the mid-2000s.

And so, no surprise, California will of course follow that pattern.

And you see the big jump up in 2003 and that's when 60 percent of the market phased out MTBE that year, voluntarily a year early. And then, in 2004 the rest was phased out. And it stayed at that lower level and then jumped again.

And you go, well, what was going on there? Well, that's because the maximum amount containing gasoline was lifted to 10 percent and that's in response to the Renewable Fuel Standard in the United States, and in California.

So, basically, Kinder Morgan, which we were talking about in a previous session, said in their system, well, all right, we're going to -- the new standard for delivering gasoline to our system is the

type of gasoline you're going to blend with 10 percent ethanol, and the entire system became that way overnight.

So, the red line is the apparent demand for ethanol and the production is all the gray lines. And then you see some things like net imports, the blue line on the bottom, which are more and more negative.

So, a record level was set, certainly, back in August of 2016, but it has dropped off a little bit since. But it's been bouncing around at this sort of level, not changing a lot, and that's because the concentration is limited to 10 percent. That's the 10 percent blend wall.

Imports are spotty. It depends on the economic and the need. But most recently all that's really coming in, and in a small amount, is from Brazil. Brazil sugar cane ethanol has some of the lowest carbon intensity of other types of ethanol and so that's more desirable in California and in Oregon.

This chart, the exports are the yellow line, the green bars are imports so, clearly, we're a huge net exporter of ethanol. And the industry is almost at a record in 2016, you know, 65,000 barrels a day. And that's expected to continue, very cheap prices here in the United States for ethanol relative to foreign

markets, including that of Brazil.

So, here is the concentration in gasoline, the 10 percent blend wall is the dotted red line. And you really don't go above that because you really can't sell gasoline about 10 percent at normal retail locations. There are more pumps that are E-15, in those states that allow E-15. But E-15 sales are seasonable. It doesn't happen during the summer months because of the evaporative emission controls. That's something that the E-15 purveyors would like to get changed.

And no, there is no E-15 sold in California. Why? You would need to modify California's reformulated gasoline specifications to allow E-15 sales. They'd have to do analysis, figure out what the relationship is between higher ethanol concentration and emissions, and develop new reformulated gasoline standards. So, that hasn't been done, so that's why we don't sell E-5.

We sell E-85 more and more all the time, and there's many more sites for E-85 sales in the U.S., 3,200. And so, that's how you get even more ethanol into gasoline than the 10 percent limit is through these other types of sales. And that's why it's now gone above the 10 percent blend wall line.

So, a couple of slides on profitability just to get you up on how ethanol people make or lose money.

And so, total costs are basically corn and natural gas, and that's the variable cost. And you'll get revenue from ethanol and distiller dry grain solubles, DDGS. And that's what can go into cattle feed. It's a byproduct of ethanol components. But that can be important, the amount of money you're getting from that.

And that's what this slide shows is the DDGS is the red, smaller part, but can be an important contribution to revenue. And this has really helped, at times, the ethanol industry when economics weren't very good, but they were able to still make some additional revenue stream.

And more recently, producers can also be getting credits for like under the Low Carbon Fuel Standard for ethanol production.

And wet DDGS, meaning you don't use natural gas to dry it. So, if you don't do that, your carbon footprint is lower, like the California facilities who don't have to transport that material very far to a feedlot, it can be wet, and they'll still get revenue for it and they'll have a lower carbon intensity.

And now, most ethanol producers, about 95 percent, extract corn oil from their process. And that's important because now that's a very valuable feedstock going into the biodiesel industry.

So, corn, primary feedstock, primary I say, not the sole, sorghum grain is being used a little bit more but it's a very, very small amount, 2.2 percent. It's mostly corn. And so, corn has really ramped up there significantly. And yes, as a percent of total it has gone up. It's 37 percent as of 2016.

But you see the blue line feed and residual a little bit more. Well, that used to be a lot more, but that's come down. So, more corn going to produce fuel ethanol and less available for feed and residual, and some of that has to do with the economics, of course.

So, economics are -- I mean, and so the ethanol that went up because of the renewable fuel standard compelled the industry to build to meet that demand, and it's held there. You know, you see the blue is on the plant, but I'm not really operating it right now, and that's gone down to hardly anything. It's less than -- it's about 2 percent. So, very understandable based on the very high demand for ethanol.

And you see in California, we don't produce as much as we need. We import 88 percent. So, that's because we have a limited number of ethanol facilities operating. But it should be pointed out, so our California rail imports, the carbon intensity of those 72.36 grams of CO2 intensity per megajoule. Yes, I

won't say that again. But Cal grain producers a little bit less and that's actually going to get a little bit better in 2017 with some of the new pathways coming up.

But clearly, Brazilian ethanol is a more desirable, lower carbon intensity, but we haven't seen a tremendous amount. You see that's the green there, the marine imports, and the very small part of total supply. And that's because as the Low Carbon Fuel Standard gets harder to comply with, the Brazilian ethanol will become more desirable than it is right now. But so will renewable diesel and biodiesel.

So, I want a few slides to talk about compare and contrast. Brazil is quite different. It's ethanol, yes, but the source is sugar cane. So, with sugar cane you harvest it, cut it, get the juice out, the cane juice and you don't store cane juice in a silo, you have to process it.

So what happens is, as the harvest season comes in production of ethanol starts, and it will go for a period of time and stop.

In the United States around the clock because you can store the feedstock long term.

Another big difference is that the Brazilian plants, they're much smaller in size, 19 million gallons a year average, and 69 million gallons compared to the

U.S. And Brazil actually has a much higher amount of ethanol in their gasoline, 27 percent. Not 10, 27. So, they really move a lot more ethanol. I guess the final point is that I guess the amount of ethanol you can get from an acre in land is greater in Brazil, 588 gallons compared to the U.S. 477. And, basically, both of those numbers of been rising, increased productivity of how they grow both the corn and the ethanol.

So, there's different types of ethanol. And there is what we call hydrous that has a water content up to almost 8 percent, and that they use in their flex fuel vehicles, of which they have very many. And anhydrous, and that's a type of ethanol that has a very small amount of water and they blend in gasoline, like that in the United States and in Brazil.

So, as you can see, with your eye, the blue, the hydrous is a little bit bigger than the anhydrous and that's because of the very large population of flex fuel vehicles in their existing stock and what's sold each year.

So, they do export, like the United States, but it's been rather stable and modest over the last couple of years because it has to do with what are the economics of producing ethanol? Will I make sugar from the cane juice or ethanol? And that happens every

single year, what's the global sugar market doing, what are the prices of ethanol, what's my demand of ethanol in Brazil?

And so, an agency in Brazil determines what that ethanol blend will be in gasoline and helps set the stage for how they'll operate.

So, this chart, kind of busy, what is below the line is what the U.S. is exporting to Brazil. What's above, we receive from Brazil. So, as of late we're exporting a lot more to Brazil than we're getting from them. And yes, that's because they had some sub-par production years, where demand is increasing, and the ethanol producers in the United States have a lower price that they're selling to this foreign market. So, it's competitive.

Exports do come from Santos. That's sort of the bottom part of that slide there, 90 percent. This is something that they've expanded the infrastructure, anticipating sending more ethanol to California and the West Coast, and to other parts of the United States to help with the advanced biofuel requirement under the Renewable Fuel Standard. So, they're gearing up to be able to do that but how much depends on how well their harvests do and the economics.

And so, in some projections it looks there's a

very modest amount, maybe an additional 400 million gallons that could come out of Brazil over the next couple of years. So, it's not large, but it positive. So, we'll see, it's all based on the economics.

And so, some people have talked about, well, Brazil can send more to the United States and they just import more back. Sort of a Sao Paulo shuffle, a Houston shuffle going on, and still end up with all the ethanol they need, but giving the U.S. lower carbon intensity ethanol in exchange.

So, biodiesel, just like that of ethanol, a record production, 1.5 billion, and that's 1.5 billion, not 15 billion. So, it's one-tenth the amount of renewable fuel compared to ethanol.

And there is a dollar-a-gallon blenders' excise tax credit that has expired many times. And all of the poor producers go, okay, is that going to be reauthorized? And yes, eventually it does happen, but it sometimes has happened at the end of the year and they've made it retroactive. So, you're taking a risk what you're selling may not lend itself to that very important dollar-a-gallon.

So, this is looking at the supply and demand. And so, blue is production. And what's interesting to note here is recently, look at the green lines on top,

they've gotten very large. And that is part of a growing trade dispute with Argentina, primarily, and now Indonesia to a lesser extent, of unfair trade practices. Why? There was an export tax on Argentinian biodiesel that was reduced and is now eliminated.

And so, I think the National Biodiesel Board is making some claims in the process to challenge this situation that they think is unfair for U.S. biodiesel producers. So, that's why you're seeing a big jump in imports there.

But exports exported less than 4 percent of total production was export. Because Europe has tariffs that say you're not going to dump your biodiesel here, and if you're going to try, you're going to pay a high tariff. And so, that's why we've seen those go way down and be a very small component.

So, the amount, greater record production, greater amount being used in diesel. In fact, a record 4.75 percent almost be 5 in everything, very, very close. But you see, well, look it drops off like in January. What is that, like everyone takes a holiday and then they stop blending?

No. What did I say before? Tax credit, oh, I'm sorry, it expired December 31st. And so, you'll see a behavior where producers will kind of do some

maintenance, shut down temporarily, the economics aren't very good and so this is sort of the drop off in the amount being blended because of that policy of not having a long term tax credit in multiple years, but dropping off.

So, just a couple of slides on operating margins to show you that, yes, like ethanol it goes through cycles and that the cost of the oil that you use, and soy in this case, does change over time. And that can change depending on what the market price of biodiesel is. Lower your operating costs or even make them -- your returns, or make them negative.

And so, the red lines have been better lately and we expect that biodiesel use will command more and more of a premium.

So, these are the feedstocks. So, I mentioned soy. Well, that's the lion's share in the U.S. The light green is 55 percent, in 2016, of all the different oils and fats you can use to convert into biodiesel. It's huge.

And so, let's zoom in on -- let's remove the soy and look at the other feedstocks. And why is because these are the feedstocks that biodiesel producers in California want to use, not soy. Soy is a very high carbon intensity compared to these other feedstocks.

And these are the types of biodiesel that we'll want to import, to use under the Low Carbon Fuel Standard.

So, take a look at this chart. Soy is the green bar. You can hardly see it. That's right. It might be 55 percent of total biodiesel in the U.S., in California 2. So, yeah, so you set up a policy here and then the market participants go, okay, what do I want to sell here or produce?

And so corn, very, very low corn oil, 5 and a half grams. And so, remarkably low and that's why you're seeing a lot of it being used here. And that's what the market wants to use, the customers and the producers.

And so, going forward we would expect to see more differentiation to a lower CI feedstock. So, this is taking, looking at the source of the fuel. And just like ethanol, we don't produce as much as we need here. We produce only a smaller portion. Most of it's important, either through rail or water, the blue, the foreign imports. And you're seeing the relative carbon intensities of -- I'm sorry, the relative volumes of those fuels. And you're seeing the carbon intensity was bounding around, you know, 40, to 20, to 40 and now down to 18.

So, it improves, but it depends on sort of the

volume needs. But as time goes by, 2017, 2018, we expect the carbon intensity to be lower. You know, not go back up into the 40s and stay there because it's going to need to be, you know, a bit lower.

So, there are some issues, you know, brought to our attention with biodiesel, so just a couple here. So, it's 5 percent now. It requires an infrastructure to go up to 10 percent or even 20 percent. And some private industry has done that.

But we're also aware that you could produce more biodiesel, but if you do that you're going to have to purchase more feedstock. And so, this becomes a cash flow issue.

So, one concept is, well, if you do sort of a loan guarantee to get me up to a higher cash flow balance that would be one way. So, a traditional bank wouldn't look at that kind of loan. But, so, this is something that we've become aware of and there are other people that know a lot more about this, and can explain better than I. So, we just wanted to raise this as an issue and bring it to your attention.

The 5 percent that I mentioned and I keep mentioning several times, well, we're going to need to use more biodiesel for the Low Carbon Fuel Standard. True. But the Alternative Diesel Fuel Regulation is an

outcome of litigation. That was started about the Low Carbon Fuel Standard, an ethanol producer, and that has resulted in the Air Resources Board developing a regulation that offsets oxides and nitrogen emissions. And the consequence is that likely there will be a cap on biodiesel starting next January, of 5 percent. So, there are some people doing 20 percent, 10, and people that want to go above 5. And so, this looks like there will be sort of an effective cap maybe in 2022. It's uncertain because it has to do with how quickly your existing fleet of trucks becomes modernized. So, that deadline is uncertain, but maybe 2022 according to the Air Resources Board.

So, this is an area certainly of concern that may make it a little more challenging for the LCFS compliance. But, you know, sort of it is what it is.

So, feed stock availability, we've talked about this I think over the years. This has come up in some of our proceedings. It's like, yeah, you can make something out of that, but how much is there? There is an upper limit, right?

And so, a couple of examples, used cooking oil, it's 22 percent of available right now. But, theoretically, 3 billion gallons is available from every single restaurant and every single corner of the United

States. Unlikely it will all be collected because the economics to go further afield go up, and up, and up, and so the cost of collection, and so it becomes uneconomical, so that's, we think, unrealistic.

Animal fats, pretty good carbon intensity, but it's a very small amount. Well, Gordon, you said it's pretty good. Well, it's a very small amount in biodiesel, but when I talk about renewable diesel it's a very important feedstock for that.

So, used cooking oil is less desirable than that. But animal and fish oils, and this is something that on a larger scale is being done by, you know, Neste in Singapore, and in Rotterdam, in their large facilities.

So, corn oil is probably the best lowest carbon intensity feedstock, and we saw that in one of the previous slides. A very important part of total biodiesel use in 2016. And so, can you get more? Well, sure, if what's exported is converted to biodiesel that's a significant number of gallons that could be used. And this 420 million of all other corn uses, and you're using corn oil to -- and you see corn oil in the store, cooking oil. Are you going to convert that to biodiesel and burn it? You could, but that's probably pretty expensive.

And so, we don't think all of the corn oil produced can be converted as a feedstock for biodiesel because of competing uses, so there is a limit to that.

The last couple of slides I'll talk about some emerging fuels. First, you know, we're not the only division in the Energy Commission, there's other divisions, lots of people doing lots of important work.

So, the Transportation Division actually looks at -- the Fuels and Transportation Division looks at -- very intensely looks at natural gas use of transportation fuels, hydrogen especially, electricity infrastructure for charging. And so, they have lots of information, and materials, and programs associated with those fuels. We weren't going to attempt to cover those fuels in our report, but just want to make everyone aware that we know there are other important fuels, but we just didn't cover them in this report.

But the last one is renewable diesel, which we do cover. And so, LCFC credits, this is showing the total credits by fuel type. And you can see, well, what's renewable diesel, the orange. Well, that's gotten pretty big. So has ethanol, but it's kind of flattening out and biodiesel has gotten a little bit bigger, too.

Renewable diesel is pretty important because 24

percent of all credits in 2016 and 46 percent of all the renewable liquid fuel credits so, a very small amount of the liquid transportation fuel and a very significant amount of credits, so this is a very important fuel for the Low Carbon Fuel Standard. And that's why we expect more of it to occur in California, domestically brought in by rail and foreign imports.

So, that's why things like marine infrastructure, not just for crude oil, but for things like importing renewable diesel, are very important going forward if any of those facilities were to come under pressure.

So, renewable diesel consumption has jumped up even more than biodiesel. This is completely fungible, you can use it, it's interchangeable with diesel molecules, no difference really, but there has been significant growth because of the Low Carbon Fuel Standard.

And this just shows you the carbon intensity did jump up a bit in 2016, but that's an artifact of some of the renewable diesel wasn't identifiable, so sort of the fallback is to use a high carbon intensity for that volume. And so, that's why it jumped back up there.

But going forward we're looking at some corn oil, animal fats is pretty low, and we're expecting that

number to drop back down in 2017, and be a record number in 2017 in total volume.

And those are all my renewable and alternative fuels. Any questions?

We're doing great. I guess you're almost sick of me, hearing me, but last of the slides. And this is really sort of to tee off our discussion with Mr. Dave Hackett and Mr. Adrian Tolson, of 20/20 Marine.

So, we want to cover what we think are three pretty important issues that come up. And these are South Coast Air Quality Management District Rule 1410, the Bay Area has a greenhouse gas cap on Bay Area refineries. And then, IMO, 20/20, International Marine Organization 20/20 is a sulfur fuel regulation for bunker fuel and marine vessels.

So, just to point out, something I mentioned at the outset here is that the Integrated Energy Policy Report happens every two years. One of the very important developments is with some issues that come up and this is that venue for that. So, yes I'm talking about three specific issues here but there are others, and I mentioned one, a couple of biodiesel ones that we want to be made aware of in the transportation fuel arena. So, we don't know all the issues, necessarily, but we want to made aware of that.

So, this process is meant to capture some of that and so that's why your feedback is very important.

So, the South Coast Air Quality Management District is looking at a regulation that has the potential to impact two refineries in Southern California. And why that is, is because this regulation has to do with the type of catalyst that a particular process unit in the refineries use, and that's hydrofluoric acid, or HF.

And so, the alkylation unit, circled in this chart here, is the most important refinery process unit producing gasoline components in the refinery. Pretty much all of the refineries in California have one and they're usually associated with the (indiscernible) under FCCU.

So, the important of this is that there's two facilities in Southern California, it's going to be nearly 20 percent of the State's gasoline production, or 25 percent, so it's significant.

And so, if we look at, well, what are you talking about in terms of your regulation? What could it possibly be?

Oh, I guess before I go there is the concern is hydrofluoric acid, if it gets out in contact with water, I mean a small amount of water, it can form a vapor

cloud, a dense vapor cloud close to the ground and it can be fatal. So, it can be dangerous like that if it does break containment, but so can sulfuric acid, of course, if it breaks containment.

So, that's the main concern here. Hydrofluoric acid is something, and sulfuric acid are the two types of catalysts used in alkylation units around the world. About half of it is hydrofluoric and the other half is sulfuric. So, there's a lot of it, but there's only two facilities in Southern California, and they're both in Southern California.

So, there are three possible outcomes to this rule. And we want to stress at this point that clearly it's not finalized. This is still in process, but the expectation is they'll finalize their rule by the end of this year and go for a vote before their Board.

So, there could be no ban, status quo, no change, no going forward with the regulation. They could do performance-based which is, well, what does that mean? Well, it's basically safety. The two facilities right now have a form of hydrofluoric alkylation called modified HF, or MHF. And they inject a chemical into this process that decrease the ability of the liquid to form a vapor cloud if it were to be released.

And the second thing they have in place are a series of water canyons that would flood the facility if there was a breach detected, and then it would prevent a vapor cloud from forming.

So, there's lots that have been done, and this has been done with the safety organizations and the South Coast Air Quality Management District, by the two facilities.

So, the ban is the one we're most concerned with, of course, because that we believe has the potential to cause a significant increase in fuel prices for all of California. And we think it could be worse than that of what happened with the Torrance ESP explosion. And that was a 26-cent average price increase for gasoline for 17 months. And you can do the math on that and that's about $5.6 billion.

So, can you just drain out the hydrofluoric and fill it up with sulfuric? No. Wish it was that simple but it's not, you can't. Essentially, you have to replace the units.

So, the ability to do that depends on how much space you have of where you could build it. Can you build it and keep the other one going or do you have to shut the other one down, tear it down, and then start building the other one? How long would it take to get

the permits and then what is the ultimate cost of that, which may make the timing moot if the cost is too great.

So, continuing to maintain operations has all to do with do I have space in my refinery, enough footprint of spare land right where it needs to be to build it, and then get it all ready to connect and then shut the other one down?

Well, we think that's unlikely looking at, you know, imagery of the two facilities, that you'll be able to do that. So, this is more of a situation, we think, where you'll have to shut the unit down, tear it down, and then rebuild, if they were to go this route.

Permits are something that I think anyone who has been seeking a permit for a complex structure in California knows it can be an involved process. But the outcome is what we'd characterize as uncertain to even receive your permit.

So, you could talk to Valero about their crude by rail permit. And Benicia, years in development and ultimately denied.

You could talk about the Chevron Richmond refinery project that took nine plus years. Yes, it's not a typo, nine plus years to ultimately get approval for that project, the modernization project at the facility. So, a great deal of uncertainty. But we have

evidence that there's been some significant time and then even ultimately denial.

The cost are really more of the important issue here. So, alkalization is a very sophisticated, expensive unit. A recent example is Valero has a project in Texas, they're doing a smaller-sized alkalization unit, brand-new, 300 plus million, I think it's 318 or 320.

And the capacity of the other two facilities, each one is nearly double this project. So, we're conservatively saying, yeah, it could cost, you know, $500 million each.

I think Dave Hackett, Mr. Hackett will talk, he has a little bit better estimate than we have here.

And so, think about it from this perspective. You're an operator of a facility, a company, and your engineers come to you and say, hey, we have a project. Oh, what's that? We want to replace the alkylation unit. Okay, how much is that going to cost? Pretty much the entire value of this refinery.

Okay, so the Board is going to say, oh, sure, go ahead and do that. So, it's possible that the Board at one of these companies would say, no, we're not going to authorize that expenditure. So, that's a possible outcome of this which would result in a closure and a

loss of gasoline.

And Dave is going to talk about the impact on California, of that kind of scenario.

So, the second issue is the Bay Area Air Quality Management District is also, not finalized, working on a regulation that is designed to limit the amount of greenhouse gas emissions from individual refineries. Not basin wide, specific refineries.

So, each refinery would have its own limit. And so, the concern is that depending on where you put those caps that you may inhibit the ability of the refinery, or refineries collectively, to operate at a higher sustained level because they're doing that, for example, when there's an outage, a significant outage in Southern California.

So, what would be an example of that? That would be this slide. This is what Ryan was talking about earlier; we have our weekly refinery report. So, this is from showing the period in the summer of 2015, where the refineries in Northern California all over produced. So, where this red line goes above the top of the blue band, that blue band is the five-year maximum high and maximum low.

So they were, at times, significantly above that band, producing more gasoline than they needed and

exporting it to Southern California to help offset the loss of supply from the ExxonMobil refinery.

So, the concern is where you set those caps, do you then set them such that they won't be able to do something like this again?

So, we don't know the answer to that and, you know, we've been working with Bay Area Air Quality Management District staff and they understand this. And so, like I said, the rule hasn't been finalized and so they're aware of this kind of potential consequence. And so, we'll have to see how this all works out.

So, I think that's enough of this rule, we'll go on. I'm told I'm exceeding my time limit. I don't know if that's possible.

So, the issue is also a bit more complex. It's the greenhouse caps for this are because of a concern of more and more high-carbon intensity crude oil from Canada. And so, this is an example of one of their most recent proceedings where CVE, showed a slide where, you know, the total crude, the average quality of the crude could get up in this orange zone. You know, much more sort of dirtier crude.

And so we looked at that and said, hum, what are the likelihood of that occurring? So, this chart shows two properties for crude oil, API gravity and sulfur.

So, the API numbers, when they go up the crude is less dense, it's the reverse. And then sulfur, on the lower access, from left to right is showing higher sulfur content. So, it's showing the average API sulfur point of the crude oil used by the Bay Area refineries moves around from year to year. And so you go well, yeah, there's some variability here. It's staying a little bit less dense and a little bit higher sulfur.

Okay, so it does move around. All right, I get it. So, let's put that into what they do. They get all those different crude oils, from all those different companies, and what do they do? They blend them together before they process the crude. They don't take a Canadian crude and blend that, and take a crude from Colombia and blend, and process that. They want to maintain an envelope of crude oil properties that are fairly stable when they put it into their refinery process unit so they know what kind of gasoline, diesel, jet is coming out after they cook the crude oil.

So, you want to do that. So, the blue dots are those properties of Canadian crude oils in 2016, in the Bay Area versus, at the proper scale, where those average dots are.

So, how much do those average dots from one year to the next move around? In this scale, hardly at all.

That's right because the refiners are trying to keep them in a very tight envelope, despite changing the ratio of foreign crudes, or California crudes, or Alaskan crudes. They're still looking for a combination of crude oils and properties, and blending them so they reach this target-tight envelope for operational purposes.

So, we don't think something, that these dots haven't moved much outside that envelope in 10 years, that they're suddenly going to go to the far right, high sulfur or get a far, far less dense crude oil up on that chart. We think that there's not the equipment to do that and there's not the operational or economic incentives to do that.

So, a final word on this is Canadian crude has certainly been going up as a source of foreign oil in the United States, 43 percent in 2015. So, more oil in Canada coming to its natural client, the United States refinery.

Not so in California. The blue line is California's average. The red is specifically the Bay Area refineries. So, yes, less than 4 percent in 2015.

So, Canadian crude doesn't want to come here. However, if it were more to come here, it would be like any other crudes, more of that, they would offset it

with other crude so they end up back in that very tight envelope.

So, the last couple of slides. So, this International Marine Organization 20/20 is a regulation designed to reduce the amount of sulfur in the fuel that vessels uses. This is global signators to this pact, this convention. And one element of it is to reduce sulfur oxide emissions from all marine vessels.

So, the concern here is, well, if the sulfur content in marine bunker fuel is pretty high, how do you get it down, lower, refinery investments? Do you make more ultra-low sulfur diesel we use now in trucking, in light duty, and you use that? So, we're not sure.

So, I'll sort of skip these because Adrian will do a better job of covering these. But there's been a study done to say will there be enough globally? No one's, you know, specifically looked at California. And that's they said, yeah, but other entities like Turner Mason, a renowned refinery expert, consultant, looked at this study and said, ah, we think a lot of the assumptions you made weren't correct and we don't think your analysis is very good.

So, it's possible by 2018 this organization can decide to delay, so that's still a possibility to delay to 2025, but that hasn't happened.

So, one final element is you can comply with scrubbers to use high sulfur diesel fuel, a distillate, and then get the SOx emissions down. Some of those do exist, the technology exists. You can use natural gas, liquefied natural gas, you can have two fuels. You can build a marine vessel that is just fueled with LNG and that's being done.

And so, Singapore is developing a liquefied natural gas sort of fueling infrastructure for marine vessels. The Gulf Coast is doing that. So, the question is, is something like that going to possibly happen in Los Angeles and Long Beach. So, don't know the answer to that.

But that's actually the last of all of my slides.

MS. RAITT: Any questions for Gordon? No. Okay, well, thanks.

COMMISSIONER SCOTT: I don't have any. This is great, a very clear explanation of a lot of details. Thank you, Gordon.

CHAIR WEISENMILLER: Yeah, thank you.

MS. RAITT: Yeah, thanks Gordon.

So, next we have a panel on the Liquid Transportation Fuels Market. And David Hackett from Stillwater Associates is our speaker.

MR. HACKETT: Good afternoon Chair Weisenmiller and Commissioner Scott. I'm happy to be here again today. Although I would say today I don't have my PMAC hat on. I have my consultant hat on.

We've been retained by the Torrance Refining Company, which is a subsidiary of the PBF Energy to talk about this issue of the impact of the hydrofluoric acid ban on Southern California transportation fuel supply.

(Pause)

MR. HACKETT: So, while we're waiting for the presentation to get sorted out, let's see, the Torrance Refinery has had, as we've discussed, had some problems, especially in 2015 when their electrostatic precipitator blew up. And that explosion, according to the Chemical Safety Board, the U.S. Chemical Safety Board, caused some concerns about the potential for a spill of their hydrofluoric acid. That's a strong acid that's used in the manufacture of gasoline.

And so, at this point the South Coast Air Quality Management District is considering, as Gordon talked about, a ban on HF acid. And so, the Torrance Refinery Company retained Stillwater to essentially do three sorts of analyses, three cases.

One case is look at the cost to replace the HF alkylation in the two refineries that are in Southern

California with these alkies, the Torrance Refinery and the Valero Wilmington Refinery. And then do an analysis of the -- in addition to replacing that, instead of replacing to shut down the alkylation units and look at the economics of running the refineries without alkylation.

And then the third case was describe the impact of the shutdown of the two refineries.

So, as Gordon has described, alkylation is an important refining process. And the way the Southern California refineries are configured, they're not able to make commercial quantities of CARBOB without alkylate. And so, you'll see in our analysis that should the HF be banned it's unlikely that the impacted refineries would replace those process units with sulfuric acid due to the high cost. And they wouldn't be viable to run, in which case they're likely to shut down.

And between the two of them, they produce about 25 percent of the regional demand for transportation fuels, and that's gasoline, and jet fuel, and diesel. And as well, if those two shut down that would leave only three fuels refiners in that market, so the competition would be reduced.

We see that offshore refiners would have to come

into the market to replace the lost volume. And you'll see in this talk that's going to come from long distance, as it did in 2015 and 2016.

And in order to be able to support those imports from long distance you would see spot prices rise considerably, on the order of 25 cents a gallon.

So, in order to do our analysis, we had to construct a regional supply demand overview. And, you know, in here we described the PADD 5, which is the Energy Information Administration's division for the West Coast.

And this is essentially the five West Coast states, plus Alaska and Hawaii. And as you can see, these are all a long distance away from alternative sources.

Can we squeeze this? Yeah, squeeze that onto the screen for me.

(Pause)

MR. HACKETT: There we go, yeah. Thanks. Okay and you previously saw this chart earlier, both Gordon and Stillwater used this from an Energy Information Administration. Basically, it's got the three refining centers for the West Coast and they're not interconnected.

And here, focusing in on Southern California,

which is the part that we're interested in today, there are six fuels refineries, belonging to five refiners. Tesoro essentially has to refineries. And they supply the transportation fuels to Southern California, and to Las Vegas, and to Phoenix.

This slide gets into gasoline specifications and it's essentially designed to show that CARB gasoline as a product, its specifications are the most stringent in the world. And so, not only is the market isolated because of distance, but also because of specification.

And because of that isolation, you know, the region is exposed to product shortages. We'll talk about that. And, of course, we saw that when the Torrance Refinery was down for 16 or 17 months.

This is sort of an extension of a chart Gordon put up. This looks at net gasoline imports. Normally, over the last, let's see what have we got here, seven or eight years, the West Coast market for gasoline has been an export market. There's been more gasoline produced on the West Coast than consumed locally.

But here, this spike in 2015, you see the impact of the Torrance problem, where the market flipped from being an export market to being an import market. Well, essentially what that means is all of the sudden the marketplace had to gear up to bring a lot of gasoline in

from long distance.

And this chart illustrates that. You can see it came from the United Kingdom, for the East Coast of Canada, from Northeast Asia, Singapore and India.

And the market prices reacted. This is one of Gordon's charts on prices. You can see price spikes here that occurred in '15, early in '15 because of the ESP problem, and then continuing issues going forward in 2015. It shows up in price.

So, now, let's turn to talk about alkylation and why it's important. And I want to start with a story. I worked for Mobil Oil for 20 years, and I hired with Mobil in Los Angeles, and my job was to coordinate the movement of fuels in and out of the refinery.

And I didn't know anything about refining, so I went and got a tour at the Torrance Refinery. And I remember the engineer who gave me the tour, the first thing she wanted to talk about was organic chemistry. You know, C1s and C2s, and the rest of that. And I thought why is that important?

So here I am, a long time later, talking about C1s and C2s because it helps to explain things. Basically what happens is that hydrocarbons, a chemical engineer counts the fuel by carbon number. So, the carbon number that everybody knows or thinks they know

about is octane. Right, so there's 8 carbon atoms in an octane molecule, and that octane molecule's in gasoline.

So here, on this chart, you can see we list them, methane, ethane, propane, propylene, et cetera, essentially by carbon number. And the ones that we're interested in here are the Oliphants, the propylene and butylene, which are alkylation feedstocks. And they're produced off the "fluid cat cracker", which is the big gasoline-making machine in the refinery.

So, you can see methane and ethane are pretty much going to natural gas. Propone goes into heating. That's what in the bottle for your grill. Butane goes either into gasoline -- well, it goes into gasoline in the wintertime and it winds up being mixed with propane in the summertime. And then, you finally get into gasoline.

But when you think about how fuels are defined and they're defined by the size of their molecules, natural gas, liquefied petroleum gas is gasoline. So, gasoline is basically C4 to C10. Jet fuel is C11 to C15. Diesel and heating oil is C16 to C22. And then the other stuff is longer chain molecules. So, if you can remember where these things all fall in, then a whole lot of other stuff about this fuel business starts to make some sense.

All right, here's a refinery diagram. The alkylation unit sits essentially next to the fluid cat cracker because it takes the C3s and C4s from -- that are cracked off of the big molecules, the FCC processes. And it sticks them together. This is many of the processes in a refinery are called "cracking", they break up the big molecules, the C22s and greater. They break those up.

But what alkylation does is it takes the small molecules and sticks them together.

And so, for refineries with FCCs, fluid cat cracking, which is all the refineries in Southern California, it's an incredibly important process because it creates this -- in the presence of a strong acid, HF or sulfuric Acid, it puts these things together and it creates a C7 or a C8, right, that go into gasoline.

And in this chart on 19, what we went into a fair amount, a lot of detail to demonstrate that the quality of alkylate is actually in the sweet spot for California gasoline. It's the, as we described, the essential California blend stock.

And this became apparent, I think to the Energy Commission, even 15 or more years ago when we looked at the MTBE phase out and it was clear that alkylate was going to be a key component to gasoline then. And we

spent a lot of time trying to figure out is this alkylate going to move around, and what happens? And what we do see when there is a supply upset, a sustained supply upset here, that alkylate comes in from abroad in order to fill out the gasoline pool.

So, all refineries in -- all of the FCC refineries in California have alkylation. I think there's one of the -- only one major refinery in California, that's the Phillips 66 Rodeo Refinery, does not have an alkylation because they don't have an FCC. It uses a process called hydro-cracking in order to break up the big molecules into smaller fuels molecules.

So, in order to do our analysis of what would it cost and what would the impact of changes in HF alkylation mean, we had to come up with a base year, and we picked 2014. That was essentially the last stable year. Stable means nothing exciting happened, thank goodness, right.

And so, we look at it both at the PADD 5 level and at the Southern California level. And once you look at these charts you can see that Southern California depends on Northern California and the Pacific Northwest to meet the demand for gasoline, plus imports to meet the demand for jet. That's kind of I'm taking right at the bottom line there.

All right, so with understanding what a stable base looked like, then we did some things to these cases. And the first thing we did was we looked at what it would cost to replace the two HF alkies.

And our estimate for the two of them would be about $1.8 billion. And so, that includes not only replacing the alkylation unit, but also adding on-site regeneration of the sulfuric acid. This is replacing HF with the sulfuric.

And those numbers are from a publicly-available report that Torrance commissioned by Burns and McDowell, along with our, Stillwater's estimates of the costs.

If you simply replaced sulfuric acid, HF with sulfuric acid at the same size, it wouldn't change the supply/demand balance. It wouldn't make any more or less gasoline. But the refiners would see a somewhat higher operating cost. And I would say that what you can see in Southern California are some very large capital-intensive environmental mandates on the horizon. Significant reductions in nitrous oxide and potentially GHG reduction issues, as well.

So, there's a capital project bill that the refiners are facing that is significant as things stand today.

All right, so then the second case was how would

the refineries look without the alkylation? And the first thing you realize is that you have to do something with those C3s and C4s. And so, you can't blend them into fuel today. You can't blend them the way they are. You have to get them out of a refinery and send them to someplace that can deal with them.

Probably, it would wind up going as far as the Gulf Coast. So, you put it on a rail car or you put it on a truck, and truck to rail, and then rail to the Gulf Coast. And so, the value of this stuff on the Gulf Coast is not very high. It certainly isn't as high as alkylate is on the West Coast.

And their facilities for moving these Oliphants, propylene and butylene out is limited. So, basically, they have to turn the refinery down to the point where they can take out, truck or rail out all of these components.

And so, what we assumed was that the fluid cat cracker would run at its minimum turn down. That is to say the level at which it can still run, but if you turn it down any farther it won't run.

And then, of course when you do that you reduce the amount of crude oil that is processed. So, the total amount of fuel that's produced goes down.

And in order to make up the lost gasoline

production you have to import alkylate.

And on slide 28, we go into the balances, into essentially what we calculated is the refinery input be reduced by 27 percent, with corresponding reductions in gasoline, jet fuel, and diesel production.

And if you did that, of course that would impact the refinery viability and the refineries would be less economic, they would be much less efficient. Their fixed costs per barrel -- the fixed costs don't change so, essentially, they'd lose gross margin at that.

And the value of the alkylation feed goes from essentially from an alkylate value to some value on the Gulf Coast, very low. So, when we ran the numbers this was not a profitable operation.

So then, if it costs too much to build new ones and running without an alkylation unit is not economic, if it's not profitable, then we've looked at the shutdown, the impact of shutting down the refineries.

Okay, so prices in Southern California are going to have to go up in order to incentivize offshore producers that might be, you know, in India, or might even be on the Gulf Coast. It's not all that clear that you can find all that much CARB gasoline, at least initially.

This is a long term issue. Eventually, offshore

producers would figure out how to do it and they would make the volume.

You know, So Cal logistics are limited, but we're going to talk about that. We think the system will support these kinds of imports. But it does concentrate the number of suppliers, local suppliers in the Southern California market.

And then here's this issue that you brought up, Gordon, on the potential problems in Northern California if the refineries up there have a cap on GHGs, they may not be able to ramp up to support Southern California demand.

And then, we've got a chart here that gets into the details of the reduction in production, 225,000 barrels a day of G plus D gasoline, plus jet fuel plus diesel, which is about 25 percent of the regional demand, according to the EIA stats.

And there will be some -- so, gasoline imports would go up, jet imports would go up. Diesel production would require additional imports. And then, there would be some reshuffling of domestic crude. We estimate that between the two refineries they run some 140,000 barrels a day of California crude oil.

And so, the 23 -- or, the 33 here shows the increases, the relative increases in imports for the

three products in order to meet demand in the region.

Marine traffic between the Ports of L.A. and Long Beach will increase. There are terminals that can handle these products. Some of them are more capable than others. Some can take pretty big ships and others cannot. But I would say that a lot of the shore tank capacity is concentrated, as you would expect, amongst the refiners.

And then, we did an analysis about whether or not this would be manageable and we have made some assumptions, and you can see this here. But we think that this level of imports would be manageable. Fundamentally, you're going to have ships coming from around the world to supply this product.

And so, as the product supply shifts offshore, then probably more crude oil will be processed in those offshore refineries than are processed in the California refineries, because the California refineries are efficient.

And so, on a global basis, that's likely to increase greenhouse gas and criteria pollutants, criteria pollutant emissions.

And we've talked about the long supply lines. You can see it takes, you know, three to four weeks, in many cases, for a product to get here.

And there will be a price impact. And we saw a price impact when the Torrance Refinery went down. And we're using 25 cents a gallon here as a kind of a steady state number. It's similar to what was -- the difference between '4 and '15 on spot prices were for gasoline.

And then, as well, we estimate that other environmental mandates will further increase the cost of fuel. And that's illustrated here, on 39, where our outlook is that LCFS credit prices will go to the maximum in 2019, which is about 20 to 25 cents a gallon.

And Cap and Trade, in its scheduled ramp up, will go up another 3 cents or so.

So, you could see that if this happened in 2020, that retail prices -- that wholesale prices, wholesale prices would go up 3 plus 24 plus 25, you know, 50 cents a gallon-ish.

And with some risk of higher prices because, you know, of global competition for the cleaner barrel, you know, if an increase -- if California gasoline demand continues to increase.

Unplanned outages, you know, covering unplanned outages are going to be tougher from the U.K., that it will be from the Bay Area, et cetera.

And then, the summary slide pretty much mirrors

the opening slide, which is this alkylation's important. Refiners probably won't run without it and consumers will pay more if these plants shut down.

Questions?

CHAIR WEISENMILLER: Thanks for your presentation and thanks for your service on the PMAC.

MR. HACKETT: You're welcome.

MS. RAITT: Thank you. So, next we have Adrian Tolson, on WebEx.

MR. TOLSON: Right. You should be able to hear me?

MS. RAITT: Yes, we hear you, thank you.

MR. TOLSON: Good. And I think somebody's going to run my presentation for me, correct?

MS. RAITT: Yes, go ahead and let me know when you want to go to the next slide.

MR. TOLSON: I will do that. Let's go to the cover, first. Okay.

Let me just quickly introduce who I am. The 20/20 Marine Energy is a consultancy company that was set up a couple of years ago. Obviously, as you can probably tell from the name, it's somewhat associated with the 2020 IMO regulations that we'll be talking about in a moment.

Just to give you my background, why am I talking

here? I've spent about 30 plus years in the marine field industry, including a 25-year stint in California working for Chem-Well that is now well-known as Glencore, but I'm well aware of the Chem-Well System and the Glencore System in California. So, I've been involved in the marine field industry for a long time.

Currently on the East Coast, so on East Coast time and so, on that note, let's go to the first slide. I'm going to give a very high level look at the marine bunkering industry, simply because I'm not sure of the knowledge of the panelists and understanding.

You know, we're always used to oil industry discussions and we tend to get left out, as we could see. And I think in a State, like California, where there's almost -- there's very little residual fuel production, which is still major fuel being used in bunkering, it's not surprising.

So, it's a 300 million metric ton market globally, about 250 million metrics tons that is residual fuel-based, about 50 million metric tons of that is distillate-based. I'm sorry, we work in metric tons, but I think everybody should be able to convert roughly.

The world's largest bunkering ports are Singapore, Fujairah for the Arabian Gulf, and Rotterdam.

Although, Singapore, as you can see is significantly large near the port, but is obviously one of the world's most important cargo ports, as well.

Historically, it's been a major -- marine was a major oil-dominated market for many years, but now is much more fragmented as the major oil companies have retrenched from refinery. And, you know, the refineries still operate but produce very little residual fuel. So, nowadays it's fragmented and their physical supply are about 20 million tons.

Also, supply is dominated by global cargo traders, like Glencore or Trafigura, names you've heard of, and some major refiners. The largest global buyers, of course, are the big shipping companies.

Apart from the physical supply, the marine industry has a complex, but necessary, middlemen that we deal through. One public company you might have heard of is World Fuels, which is based in Miami, which is the largest seller of bunker fuel globally.

There's limited regulation of our industry, with the exception of Singapore, the City of Singapore is heavily regulated. And so for that reason, the IMP regulations are a bit of a shock.

The next slide. I think you have to look at where IMO, which is the International Maritime

Organization, it's part of the UN, for your information and it started, essentially, overseas. International shipping, every ship in the world has to be IMO registered, as many of you all now. So, it governs shipping in a somewhat bureaucratic fashion.

It all started, really, with Mapolanic 6, in 1997, which is marine pollution, which started to regulate vessels. The first enforcement of any kind, as far as sulfur was concerned, actually happened with the first SECA now known as ECA. It was really a sulfur emission control area and no it's just an emission control area. Which in the Baltic and North Sea, the acid rain in Scandinavia was the biggest concern there, and so sulfur was limited on bunker fuels to 1.5 percent, and the global sulfur cap on all fuels consumed globally was dropped to 4.5.

It went through a steady process of ratcheting down and we came -- we now have a North American ECA, which came in, in 2012. What ECCA means is that you can't burn fuel within -- any fuel within 200 nautical miles of the U.S. coastline, with anything greater than .1 percent sulfur. So, essentially, it's a distillate market 200 miles within the coastline of North America, and that includes Canada.

The big change that took place is the January

2020 global sulfur cap dropping to .5 percent. That's on all fuels used globally, inside and outside the ECA.

The next slide, please. I hate to burst Gordon's bubble a bit, but this is totally ratified on October 27, 2016. The IMO made a decision that they would go ahead with 2020, 1st January 2020. There is no change on that. It will not change to 2025. They're not going to turn the clock back. So, we are facing perhaps a two-and-a-half-year learning curve in order to adjust to this.

The next slide, please. So, there was no hope -- the delay was hoped for to 2025 but, logically, in the end, I think the powers that be decided it would have to happen sometime, so it might as well happen sooner than later.

They cast aside, IMO cast aside concerns that there were any shortage of fuel to meet the new cap. The CE study was mentioned by Gordon. That study is shaky, to say the least, but it was enough justification for a group that really only wanted to vote one way.

The existing ECA stays in place. This will be a 200 nautical mile .1 sulfur area. Outside that, it would be .5 percent sulfur.

The only exception to this cap are vessels that are running abatement or scrubbing technology on board

and we'll touch on that in a moment.

I mean, from a bunkering point of view, this is a total paradigm shift for bunkering shipping and, to be honest with you, much of global refining.

The next slide, please. To give you an idea of the impact of this, this is a graph I borrowed from a colleague of mine, in the industry, Robin Meech, from Marine and Energy Consulting. And essentially, the red line indicates a total demand for bunkers, you know, going forward. You know, there's that slight difference in figures I gave you. There's a lot of variations on how big the bunker market is. Nobody actually knows, by the way, because not even the IMO keep global records of how big the bunker business is.

But if you look at the black line, that's the residual fuel consumption. And, essentially, so we go merrily along with residual fuel consumption, increasing until about 2020 and then we fall off a cliff in one year, and we reduce it down to about 50 to 60 million tons.

Some of that will be fuel being burned, some of them will be in noncompliance and we'll get to that discussion in a moment, about how that can happen. But there will be also some of the fuel will continue to be burned, obviously, being put into scrubbers. But in a

moment we'll also discuss there are precious few scrubbers being used.

The distillate and I use that for .1 percent to .5 -- that's at .5 percent. So, the actual fuel spec is .5 percent, so our assumption is that it will contain a significant amount of distillate. It may obviously be a blend of different components and, again, we'll get to that.

But as you notice, that immediately compensates for that gap and so we end up in a significant increase, in 2020, in the global distillate demand.

The narrower of lines is essentially because we expect there to be a greater uptake in scrubbers coming in, as the years progress. Although, obviously, the residual fuel production will be declining globally and we will see, therefore, a bit less diesel being consumed.

The next slide, please. So, how do supplies meet the demand for 2020 compliant fuels when the spec comes in? There's a possibility to refine 8.5 percent low sulfur fuel oil, if you have the right crudes, or the right refinery with the de-sulfurization and you can certainly do that.

The second solution obviously is blended .5 percent low sulfur fuel oil, which will likely be a

blend of fuel oil in different components and a lot of distillate to make 8.5 percent low sulfur fuel. I think there will be a lot of distillate. We call it DMA, which is diesel marine grade of diesel. But, essentially, it's a distillate material that, with less than .5 percent product specification that will be used just without any fuel or component in it.

And the other alternative, of course, is to supply alternative fuels, such as LNG, and we'll touch on that in a second.

Is there going to be enough fuel? And what happens to all that high sulfur fuel oil? These are the questions.

The next slide, please. This is a PIRRA slide, that I sort of used in an earlier presentation, earlier this year, which is quite interesting in the sense that -- and I think there's a lot of pluses and minuses here regarding this is what will happen in the cumulative changes in the next four years, in global refining.

But I think the key issue is to go to that yellow at the end, the long and short of it, and you see that middle distillate is short 14 -- this is 1.4 million barrels per day, and high sulfur residual is long 1.5 million barrels per day. So, it's obviously a significant amount.

How that's filled, and you can see there are suggestions there of scrubbers, which we talked about, a high utilization of existing coking, they give 3 percent. The high to low sulfur swap for FCC units, maybe 300,000 barrels a day. So, they're filling the gap with various potential ways of using more residual and producing more distillate to balance these out.

In essence, there will still be likely a significant amount of high sulfur resid. in one of the areas it's likely to go into because, you know, you make a certain amount of petroleum coke is to end up in power generation. And probably not in this country, but in other parts of the world and we'll get to that in a moment.

The next slide, please. Let's look at the impact of global sulfur caps on price spreads. One of the key indicators here, key discussions has been how the price -- what will happen to the price? It's very difficult for refiners to make, or anybody to make, price decisions. Ship owners and what, they're going to do onboard ship, refiners to make decisions on what they're going to do as far as investment in refineries, until you know what the cost impact of this will be.

But as far as if you look at today's world, which is the 2017 scenario, the spread, this is in

dollars per barrel, between high sulfur fuel oil and distillate is somewhere in that 20 to 25 area. Fairly low, not a particularly high, real expectation that jumps to the 50 to 60 range right as we hit 2020, and leveling off again as we see perhaps the world adjusting to it, we see more scrubbers coming in. But a significant jump and a significant break in the spread between distillate and high sulfur fuel oil.

Which will, obviously, encourage people -- which will obviously make fuel an extremely cheap product essentially being sold in a disposal method and, obviously, put more, greater pressure on the distillate structure.

The next slide, please. For compliance, ship owners have essentially have a limited number of choices. And so, they can burn the .5 percent compliant fuel, as you said, compliant fuel that's a significantly higher cost than the existing 3.5 cost. So, they've got that cost structure.

As you can see from those figures, it's going to be very significant, somewhere in the $40 to $50 barrel range.

They can convert engines, or build new builds for alternative fuels, like using alternative fuels like LNG and methanol, and some of that's underway and we'll

get to that a little bit later. They can install abatements, current technology, and continue to burn max 3.5 percent fuel oil, which is appealing in some cases and we'll look at that.

And the other side of it is simply noncompliance, and this is one of the concerns. Most developed nations are signatories in the MARPOL agreement. The United States is a signatory to the MARPOL agreement and has actually -- and it has been ratified by the U.S. Government, so this is the law of the United States and will become a law of the United States, as well. And I don't think it's likely that anybody's going to turn back what's happened on the global sulfur cap, so we anticipate that will happen.

But in certain parts of the world, certain parts of the world where there is noncompliance and where they aren't signatories, and the question is will there be certain areas in the world where ship owners, the enforcement of burning this low sulfur material is not there.

Also, of course, will it all be available. If you run into shortages in some regions, you may have to have some ability to break out of that system.

The next slide, please. LNG is a compliance solution. LNG is a clean, but not clear alternative.

And what I mean by that is the biggest problem with LNG is there's no infrastructure for LNG for marine at the moment. There's massively significant infrastructure and logistics development cost. The bunker industry has never had an enormous amount or spent an enormous amount of money on infrastructure. It's borrowed other people's infrastructure and leased barges. Most of the bunkering companies are not heavily capitalized. And the LNG project is an extremely expensive project.

And one of the problems is that if you build an LNG liquefaction plant and you develop the LNG barges that can be used for delivering LNG, do you even have a customer base. At the moment that's not clear.

Even at this moment there's no clear price advantage to alternatives, like burning diesel or whatever, there's no real major price advantage that jumps out and slaps you across the face. So, again, there's nothing pulling it into LNG. It may be a cleaner and better solution, but price wise it doesn't make all that sense.

I think in Europe there's a lot of support for its short-haul usage, particularly in Europe, you know, and I think intra-European roots, particularly in the North Sea, the Baltic area I think it's very likely to happen. It's already happening.

And perhaps the U.S. Flag solution, but the U.S. Flag solution, for U.S. Flag vessels is still hard to justify. The economics are very hard to justify. It's more, you know, it's difficult at this moment to come up with that.

Now, Tote is a company you may have heard of, is a shipping company that's based in Seattle that operates vessels, both on the West Coast and East Coast of the United States. And they have already started a project in Jacksonville. They've built a barge to supply LNG to vessels, along with some partners, and they will be taking LNG on board, already are taking LNG on board a couple of vessels that I think run into Puerto Rico.

Tacoma, they also have a plan to do the same in Tacoma. It's not started, yet, but that's in their goals.

Matson recently announced that they're building geofuel vessels with LNG and traditional fuels, i.e. fuel oil or diesel vessels. And this is what they call the kind of lower class. Matson is the main vessel system that runs to Hawaii, so that is an area where -- but I believe these, generally speaking, perhaps are not economic decisions, but at the moment they're going with the clean solution.

The next slide. So, a look at the abatement

scrubbing technology, this is a massively compelling argument. And one of the things, particularly if you see those differentials between diesel and fuel, it's a massively compelling argument. The cost to build a scrubber on board a ship, to install the scrubber, retrofit a scrubber could be a relatively expensive proposition. But, you know, somewhere between that five and ten million dollar mark it can be done on a modern container ship. If you build it from scratch, in the shipyard, then it certainly doesn't even cost that much, it would probably be less than that.

But even at today's prices, the current payback level for installation of a scrubber is only one to three years.

If you have a massive gap opening up in 2020, between fuel oil and distillate, the payback could be less than a year for a modern, ultra-large container ship. So, the economics are completely justified.

So, there is a general feeling that scrubbing of what is left of the fuel oil market will become a solution post-2020.

The next slide. Just for those of you who don't know much about it, I'm going to go through this because there's various issues associated with scrubbing. We have what's called open loop, closed loop, and hybrid

scrubbers. The closed loop, currently under the IMO, and they're all possible under MARPOL and co-possible under IMO's regulations. One of the bizarre things about this is that open loop actually discharges its -- the product of scrubbing, the particulates and metals back into the ocean, which is clearly not going to be something that most ports, and most countries are going to want happening on their coastline at some point, so despite all the scientific arguments as to why that's a good thing or not a good thing.

So the assumption is this will be a closed loop situation, but that is the general. There's lots of companies selling scrubbers. DuPont is one, obviously, but that just gives you an idea what's going on.

The next slide, please. So, let's go to California which is, after all, what most concerns everyone here. The California bunker market in 2017, just to give you a spec, it's a 5 million metric ton market, approximately. Los Angeles, Long Beach, the biggest, 3.3 million metric tons. Glencore, Aegean and Chevron are the biggest suppliers there.

Chevron Richmond and, you know, why are we talking about bunker supply in a discussion about California energy? Chevron Richmond is the only significant producer of high sulfur fuel for bunkers in

the whole State of California. And those bunkers are generally sold in San Francisco and Los Angeles. You know, in the market that currently is approximately 90 percent high sulfur fuel oil and 10 percent distillate, DMA distillate.

The majority of the sulfur fuel oil supply is -- the majority of the high sulfur fuel is actually still imported from Latin America, Mexico, Ecuador, Peru, not unlike some of the crudes we're processing at refineries, as we just heard earlier on today.

The West Coast of North America and South America produce a lot of excess high sulfur fuel oil. So, currently, it's a very competitive market and there is significant amounts of excess high sulfur fuel oil exported. Particularly, Mexico to the south of us, or south of you guys, is an extremely large producer. It's really unsophisticated refining, or refineries, so they have a lot of excess high sulfur fuel oil production.

The next slide. So, here we are in 2020 and things change, right. Suddenly, you have a market that has to shift completely into being essentially a distillate or a distillate-based market, away from fuel oil. So, suddenly, that becomes an impact on the refineries, what happens to a refinery.

Here's the biggest issue that Chevron, who is

the biggest producer of fuel oil in California, apparently has no plans for a refinery upgrade for the West Coast. Well, I mean they're not even going to install a coker as far as their refinery. So, what happens to the high sulfur fuel oil? And this is a question that -- their high sulfur fuel is a question that nobody has an answer to. Likely, they're high sulfur fuel oil production will be somewhat in vessels with scrubbers, if there are vessels with scrubbers by then. And a significant generation which will mostly be exported for power generation usage.

California is a major producer of diesel, as we know. But it generally is not competitive today to Asia's new refineries. Many of you have heard about the massive growth in refining in Asia and the Indian subcontinent. So, Los Angeles currently is at least $50 per metric ton for gas oil, and GODMA, below -- sorry, Los Angeles is above Singapore, if not higher than that. So, it's unlikely that it will draw -- it would be competitive with the Asian markets.

These ships that we're selling to in our business tend to go specific, they're container ships. So, their competition to us is it's Hong Kong, Shanghai, and Singapore, and locations like that.

California producer refineries produce large

quantities to blend LSFO. One of the advantages of having sophisticated refineries is you have a lot of components, various distillate cuts, gas oils, DGOs that can be blended in to making 8.5 sulfur. So that gives you an interesting angle.

One of the other very interesting angles that a lot of people aren't aware of is that California domestic crude, some California domestic crudes is on spec -- is an on-spec bunker fuel and can be exported, as we know now can be exported if necessary.

Right now those domestic crudes in California are being put right into the California refining system, but there's no reason they shouldn't be pulled out. Their value that's a bunker fuel that's on spec and relatively low sulfur, as we know, that can be blended into a .5 sulfur is quite interesting and I think that's one thing that will take place. If my memory serves right, that use to be called Line 63 crude oil. I'm not sure it's called that anymore, but that is an on-spec bunker fuel. And the key indicator, the key issue there is the flash point level.

And also, U.S. domestic shale crudes have a role to play post-2020. And what I'm thinking with those, you know, what could happen and this one thing that's already being explored a bit on the West Coast is if you

can process in a relatively unsophisticated, old refinery, domestic shale crude, just by topping that crude in order to produce a low sulfur fuel oil that can be run in those refineries -- run and created for the bunker market. And that's a discussion that will have to take place. That's an idea that needs to be developed more.

The next slide. So, what's going to happen in California? I think, to go on with it, demand will be satisfied essentially by limited low sulfur fuel oil production. Some of that could be crude, as we talked about it before. Blending of low sulfur fuel with using low sulfur .5 percent using diesel and other components, and a certain amount of residual that will still be around.

DMA suppliers we discussed. But it's likely the market in California will contract and probably shrink by as much as 20 to 40 percent over what it is today.

The winners in this game will be, without a doubt, the blenders, the importers, the carbon traders and, of course, those refiners that can increase their distillate production and produce a product that can be sold into that blending market or, alternatively, a product that can be on-spec and ready for the .5 percent market.

The losers, at least on the fuel oil side, Chevron. I think that they will lose out and I'm not sure how they're going to deal with that situation. But, clearly, that will be a question that needs to be answered. I'm not sure they'll lose out on the distillate side, they certainly can provide distillate. But, you know, they will be one of many people who can provide large quantities of distillates is my guess.

And, of course, the specialist NGO supplies. I don't know how you bring that in, but there's a few companies that provide specialist NGO to the marine market, marine gasolines and marine market that will probably be swamped by the bigger guys, now that it's no longer 10 percent of the market, but 100 percent of the market, effectively.

And let's go to the last slide, I think. Summary, okay, the 2020 regulation is a complete game changer for bunkering, shipping and global refining. Perhaps not so in California, but certainly a significant change. There's considerably doubts about product availability. It's challenging for supplies to meet demand and buyers to purchase compliant fuel. There's no question it's going to be a very interesting dynamic on January 1st, 2020.

There is a confusion about prices. It delays

decision making, it delays investment decisions. If somebody could get a clear decision on what the differential between fuel and diesel is, I think they might consider installing a de-sulfurization capacity in a refinery, or even in a separate unit. But until that clear indication comes, which won't happen until post-2020, nobody's going to do that.

Your compliance choices are really buying compliant fuel or scrubbing. It will be a major disruption of the California bunker market, with probably loss in demand, ultimately, or reducing the size, and more volume going to Asia, as has happened over the years, anyway.

But I have to say that there's still a variety of (inaudible) in the California -- the California refining industry will probably sustain the market and give its own niche volume and niche level.

And that is my last slide and I'd be happy to answer any questions.

COMMISSIONER SCOTT: Thank you so much for that excellent presentation. This is Commissioner Scott. And I have a question for you, back on your slide, the one right before the summary slide. Yes, this one.

So, you mentioned that it's likely the market will contract in competition with Asia and will shrink

by 20 to 40 percent. Is that because you anticipate a greater capacity in Asia and a more competitive price, or what's driving that?

MR. TOLSON: Yeah, I think it's a more competitive price. I mean, despite the fact that there are some supply solutions within California, ultimately the lower price of distillate in Asia, which I think will carry on even in a post-2020 world. Because it's a global demand and they're going to have demand on their product, too. I think that will tend to draw demand away. But that's a very speculative figure.

I mean, you know, the problem we're having in the industry right now is it's almost impossible to analyze any -- there are so many different answers to so many of these questions. Because it is such a game changer and until we get very close to the actual date, I don't think anybody's going to know exactly what will happen.

COMMISSIONER SCOTT: Understood. Understood, thank you. No more questions from the dais.

MR. SCHREMP: Adrian, this is Gordon. Hey, thanks so much for that presentation. I had a clarifying question for you. On that same slide, you're talking about blending low sulfur fuel oil using diesel. So, specifically, could that be an uptake in ultra-low

sulfur diesel fuel that's currently produced and, say, exported to foreign destinations?

MR. TOLSON: Yeah, I would say so. I mean, I think that would be an obvious -- you know, obviously, there will be a certain amount of increase in just the marine gas oil distillate market, as well. So, the fact is that you're going to replace -- even if we take a 40 percent market drop and say that California goes to 3.5, or 3 million tons of bunkers, you're going to have to replace what was 3 million, approximately 3 million tons of residual bunkers by 3 million tons a year of distillate bunkers.

So, that's clearly going to be drawn from California. Some of it's going to be blended with blends that will be done using different refinery components in different refineries, is my guess. But it will certainly draw from the ultra-low sulfur diesel pool, yeah.

So, the pressure is going to come on the ultra-low sulfur diesel pool because that's ultimately the easiest way to cut sulfur. Not necessarily the cheapest way, but the easiest way to reduce sulfur.

MR. SCHREMP: Okay, thank you. And on the LNG, I know you mentioned some regional markets and developments in, say, the Gulf Coast and Florida. But

you really haven't seen any activity in Long Beach, L.A., anybody trying to have some sort of commensurate LNG supply availability such that you could to transpacific voyages with an LNG vessel.

So, you don't see any of those developments do you, so far in Southern California?

MR. TOLSON: No. One of the parties that was involved in the Tote Jacksonville project has looked at developing something in Southern California. But they aren't willing to do anything until they have a customer. And so, this is very much the chicken and the egg, if you understand what I mean, until somebody's willing to step up, as Tote did and basically pay for that infrastructure in some fashion or other, then it's unlikely to happen.

No, there are no projects at the moment, as far as I know, in L.A., Long Beach, or even San Francisco for that matter. And, you know, obviously the party that is most interested in that would be Matson because, you know, they've already committed. But they also committed to geofuel vessels. So, you know, they theoretically may never use the LNG portion of their vessel.

MR. SCHREMP: Okay, thank you very much. All right, I guess that's it. Thanks again, Adrian, for

helping us out. Really appreciate the information you provide to the record, so thanks again.

MR. TOLSON: Thank you.

COMMISSIONER SCOTT: And thank you very much for staying late.

MR. TOLSON: No problem at all, thanks.

MS. RAITT: All right. So, next, we have Ryan Eggers, again, from the Energy Commission, to discuss proposed transportation fuel price cases for the 2017 IEPR.

MR. EGGERS: Hello again, Commissioners. I'm Ryan Eggers, once again. We are running a little bit late so I am going to try to go through my slides fairly quickly here. So, do feel free to stop me if you need more explanation.

A quick introduction, this presentation is really about just giving the reasoning behind our proposed transportation fuel price cases. And first, I'm going to talk about crude oil pricing, as you've kind of heard today that really forms the backbone of a lot of the prices we see here, in California.

And then, I'm going to go into how we actually got to the final retail transportation fuel prices in part two.

So, it is the assertion of my presentation that

pretty much crude oil pricing worldwide is based primarily on world petroleum supply and demand fundamentals, primarily. Exchange rate fluctuations also do play a very important role.

Now, these aren't the only considerations in crude oil prices. The specific gravity and sulfur content and the specification of the crude oil does matter. Oil production project costs go back into supply, or back into the supply fundamentals. Economic and population growth, that's a sort of a demand concern. Political unrest can affect supply, so, again, we're all kind of back to world petroleum supply and demand fundamentals in all of this.

Now, this particular chart pretty much gets to the supply/demand imbalance that Gordon talked about earlier. What you're seeing here is black bars indicate where crude oil production is outpacing world crude oil consumption. So, as you would expect you would have a downward pressure on prices in that particular case.

Crude oil prices, on this particular chart, are the green line. So, when we do see a run of black lines, we do see a downward sort of trend in prices.

Now, red bars indicate where consumption is outpacing production, so we have demand outpacing supply. And then, in this particular case, we would see

an upward pressure in prices and we do see prices going up for the most part in this graph.

Red bars here, between 2001 and 2002 we do see a corresponding increase. Here, between 2006 and 2008 we have a long run of red bars and, again, we see a very pronounced increase in crude oil prices. We see this again from 2010 to 2013, a long run of red bars, high crude oil prices.

And now, we're in the reality we're in now. We've had very sustained production outpacing consumption and very low crude oil prices.

Where this particular analysis sort of breaks down is right here between 2004 and 2006. And at this time, this is where the value of the dollar in relation to the international market really comes in. The value of the dollar on the international market is indicated in this particular chart as the blue line. And so, as the blue line increases, the dollar is weakening. Thus, the purchasing power of the dollar on the international market is less and it requires more dollars to purchase each barrel of oil. And that would put an upward pressure on prices.

So, when we do see this line go up, we also see corresponding crude oil prices going up as well. And that sort of explains why, even though we had a downward

pressure on prices of production outpacing consumption here in 2004 to 2005, we still see increasing prices during that time because that upward pressure on prices was sort of overcompensating for that.

It's also a possible explanation of why we saw such accelerated crude oil price increases here in 2006 and 2007, and why such a pronounced decrease in prices down here in 2014 to 2016.

Now, as I mentioned earlier, that's not the only consideration in crude oil prices. Right here you're seeing the spot market price for West Texas Intermediate, also known as WTI the Brent spot price, the Alaskan North Slope, which is the green dotted line, and the California Kern Oil spot price, which is the purple dotted line.

What you're seeing here is both the WTI and Brent are usually priced above both the ANS and the California crude oil -- or, California Kern River crude oil. And the reason for that is both WTI and Brent are light crudes. They usually have a 40, or roughly a 40 API gravity weight and they tend to have lower sulfur content. Thus, they're a little bit easier to process and thus demand a little bit of a premium on the international market.

ANS and Kern, on the other hand, are more heavy

to intermediate crudes of roughly an API of 30 to 18, and they tend to have a lot more sulfur, so they tend to have a price discount.

That being said here, they all sort of track in the same sort of manner. They all have their own relative orbits, if you will. And so, even though there is some price differences in the quantity it is still world supply, it's supply and demand fundamentals that are driving these prices up and down at any given moment in time.

Now, there are locations where this sometimes does break apart and that's this circle right over here. During this time, between about 2011 to 2014 this is when all the shale oil, that Gordon talked about earlier, started really come on stage and started flooding the Cushing, Oklahoma terminal. In order to get crude oil out of that particular location they did have to discount it, and that's why you do see the disconnect between WTI and Brent during this particular time period.

Now, with that said, we do have a pretty good idea on what determines crude oil prices over the long term. That being said, we do have some serious challenges moving forward when we get to the actual forecasting part of this. And probably the biggest one

is we have no world energy or crude oil equilibrium model to actually do this work.

That being said, there is a very simple solution, we can just take somebody else's. And pretty much all the other problems that are listed here are solved, if we just look at some other agencies' forecasts.

Now, whenever we get to looking forward in order to make a crude oil price forecast or evaluating other agency crude oil price forecasts, we want to at least take a look at what's available for crude oil moving forward. And what you're seeing right here is an EIA map of technically recoverable shale resources, both gas and oil worldwide.

The dark red sections are known and estimated locations for both oil and gas. The tan areas are locations that the EIA know resources exist but they haven't estimated.

So, this work was done back in 2013. And when it was done, overall they estimated that there was roughly about 345 billion barrels of shale resources that could still be recovered.

That being said, while that does seem like a really big number, at current consumption levels that works out to be maybe an extra ten years' worth of

recoverable oil still available.

That being said, this work is still in process. In April of 2015 the U.S., as a matter of fact, was reestimated from 58 billion barrels and they were reassessed back up to 78 billion barrels. So, there might be still more out there, but this is a limited form of a resource that we can extract into the future.

Now, talking about production costs for these, this is a production supply curve that I was able to get from 2009 that was done for the IEA and the OECD. And it puts shale resources at, you know, roughly the cost to actually produce these particular resources were anywhere between roughly $65 to $130 per barrel to produce.

And then, from 2010 to 2014 we did see a price point of roughly about $120 to $100 a barrel during that time that very much incentivized the development of this. And this very much led to the increases in crude oil production that Gordon talked about earlier.

Again, like Gordon talked about, in 2015 OPEC really did try to lower the price and kill off this production. That being said, there was enough development work that this shale oil probably shifted down on the production curve. Because right now we're seeing, even at a price point of about $50, there is

still quite a bit of Permian shale coming online and it is being profitably produced.

Now, that kind of covers what we kind of see going on, on the supply side. The demand side really comes down to people. And what you're seeing here is the top ten nations in the world, in both 2016 and in 1995. And the list hasn't really changed, their positions have.

But what I want to point out h

ere is both China and India have over a billion people, and they are the second and fourth largest consumers of crude oil, respectively. And it really has to do with their immense populations, because there per capita consumptions are really, really low, and they're actually below world averages.

As a matter of fact, China only uses about a third of a gallon of crude oil per day, per person. India only uses about a tenth of a gallon a day, per person, of crude oil.

That being said, both of these economies are looking to improve and to develop. And say, if they just got to Japanese, the current Japanese level of 1.4 or one and a half gallons per day, per person, they would account for 47.7 million barrels per day of

consumption and 44 million barrels per day of consumption, respectively, which would total about 95 percent of total world consumption of crude oil.

As a matter of fact, people are trying to develop the world and alleviate poverty worldwide. If the world per capita consumption increased to the Japanese level, basically we would see a 2.6 fold increase in consumption worldwide relative to today's totals.

So, with all that said, staff did look at as many forecasts, from different agencies, as possible. And what we found out is nobody's really good at forecasting crude oil. As the earlier graphics indicated crude oil prices, you know, they fluctuate all over the place.

As a matter of fact, when I was hired in 2008, crude oil prices went from $80 all the way up to $140 and then collapsed to $30 within the first few months of me being employed at the Energy Commission.

That being said, we did learn a couple of things looking at EIA forecasts over time. One of the things we did learn is the EIA tends to under forecast future crude oil prices when we're in a low price crude oil price case. And then, they tend to overestimate future crude oil prices when prices are high.

IEA, on the other hand, tends to always see crude oil prices going to the $120, $130 area no matter where they are on the forecasting curve.

OPEC, currently, is looking at about a $70 per barrel out in 2030 projection. World Bank has a sort of a steady $56 a barrel projection.

So, after looking through all of this, we did decide that EIA was probably the best forecast for us to go with for our crude oil price forecast, not only because they sort of split the difference between all the available forecasts we could actually find, but they also had a high and a low price scenario.

And so, by using the EIA forecast and using it for all high and low, we do stay consistent within a forecasting methodology looking forward.

Now, here are the EIA crude oil price scenarios. That high price very much would represent, say, China and India developing very quickly, putting a very immense demand upward pressure on prices very quickly, getting crude oil prices up to roughly about $190 a barrel by 2030.

The mid case is more of just sort of a gradual increase of prices up to roughly about $80 a barrel by 2030. This would be very similar to what the historic trend in prices from 2000 to 2016 has been. So, if you

did actually run a regression, you would come up with a line that would be very close to that 2030 price point.

In the low case, this is where we would have continued production likely outpacing future consumption, and likely a lot of alternative fuels being able to help compete against crude oil, thus keeping the price down moving into the future.

So, I do apologize I went through that very fast. That being said, Gordon did cover a lot of my main points. I wanted to quickly pause and see if there are any questions on crude oil, specifically?

COMMISSIONER SCOTT: I'm good.

MR. EGGERS: All right, part two we get more into the liquid fuel transportation pricing and all the other transportation fuel pricing scenarios.

Now, in the case of gasoline, our price forecasting methodology is pretty straight forward. We have that crude oil price, then we establish a margin for both regular gasoline and diesel. We usually call this the rack to retail price margin.

We then, since California has two carbon programs we need to account for, we then added carbon price adders in to account for both of those programs. Then, we added the appropriate taxes, both California and Federal excise taxes and fees. And these particular

taxes that we did include, did include changes for SB 1 that took place or were just ratified earlier this year.

COMMISSIONER SCOTT: A quick question, Ryan. When you say the regular grade gasoline, so is that -- so, that's not premium, but is it the --

MR. EGGERS: No, this would be 87 octane gasoline.

COMMISSIONER SCOTT: 87, okay.

MR. EGGERS: Which is by far the most consumed gasoline here in California. But thank you for making that point, yeah.

A couple of assumptions before we get into SB 1. The first is in real terms we do hold the fuel margins that I'm going to discuss later, constant throughout the forecast period. This means that they would increase nominally. But for inflation-adjusted purposes they would stay static, so they would all be relative to the 2016 price in this particular case.

For excise taxes and fees, again we do hold those constant in real terms. Now, because of the changes with SB 1, this is not so much of an assumption anymore, this is actually what's going to be reality from 2020 on.

On the Federal side, though, it has been 18.4 cents for a long, long time. That being said, we do

assume by holding it constant in real terms that the price will need to go up in the future, as transportation project costs also have to increase into the future.

Now, we are also -- this is probably the biggest one of the assumptions we're making. We do assume that the current fuel specifications for both gasoline, also known as RFG, and diesel remain constant throughout our projection periods. Any changes in either specifications and all bets are off.

That being said, at the very bottom, this is pretty much how it all works out mathematically. We take the RAC price, we add the margin, state and federal taxes, state program adders, and then we all multiply that by the sales tax.

In the case of the diesel it's a little bit more complicated. We have the rack price, plus the margin, plus the state excise tax, plus the state program adder, then we multiply that all by the sales tax, then we add the federal excise taxes. Diesel is very unique in the fact that the federal excise tax isn't multiplied by the sales tax.

Now, SB 1, this was recently signed on April 28th, 2017. It's a change to both the state and diesel tax structure, excise tax structure. And by 2020 it's

going to phase out the 2010 changes to the gasoline and diesel excise tax structure that happened under the Schwarzenegger administration that's often referred to as the fuel tax swap structure.

Now, one of the things that was introduced as part of the fuel tax swap was this price-based, and a base portion excise tax. And what's going on here is when the 2010 excise tax changes were made part of the reasons for that change was to keep revenue-neutral the transportation fund for the State of California. So, what they did was they lowered the sales tax rate and increased the excise tax. And so, every year since 2010 the BOE has been charged with adjusting that number in order to keep that fund revenue neutral moving forward.

Now, SB 1 basically changes that. And this is kind of how it break down. Now, SB 1 doesn't take effect until November 1st, 2017. So, the first two lines here are still the old tax structure in place. So, on June 30th of 2017, the base excise tax was 18 cents. Then, another price-based portion of the excise tax was added, which was 9.8 cents, for a grand total of 27.8 cents being the excise tax on June 30th, 2017.

Every year, as part of the fuel tax swap, every July this price-based excise tax portion was changed. And for this year, on July 1st, 2017 it increased

roughly about 2 cents to 11.7 cents. So, when we add the base excise tax of 18 cents, we get 29.7 cents excise tax rate. Now, this is what it is today and it will be until November 1st, when SB 1 first starts to take effect.

And the first thing it does is it does increase the base excise tax 12 cents, from 18 cents to 30 cents. And so what that does is then you take the base excise tax of 30 cents, you add the price-based excise portion of 11.7. That will take the grand total of the State excise tax up to 41.7. Okay.

Now, on July 1st, 2018 the 2010 regulation and the 2010 adjustment will still be in effect. And so, the BOE will have to make a determination on how to adjust the price-based excise tax, and that's why the question marks are there because I don't know exactly quite what that adjustment is going to be.

For forecasting purposes, we're just going to assume it's the same value for 2017.

That being said, then the second part of SB 1 is on July 1st, 2019 the price-based excise tax will be reset to its 2010 value, which was immediately right after the financial difficulties of 2008 and 2009, and we had a very severe reduction in gasoline consumption. So, to hold the transportation fund revenue neutral, the

price-based excise tax was very, very high.

And so, by resetting it back to 17.3 cents, we then add the base excise tax and we get a State excise tax of 47.3 cents. Now, from this moment on that 47.3 cents will be locked in. And starting in July 1st, 2020 SB 1 will also dictate that it will be increase that year, and every year after, by the Department of Finance's CPI Index.

Now, that's the bad news. The good news is that gasoline does have a very low sales tax rate. So, the only additional tax that you would need to add on the State side would be a 2.25 statewide sales tax. And then we also include, for forecasting purposes, a 1 percent average locality tax. Now, the locality tax does change depending on the location you're in. Roughly about 1 percent is what the BOE uses as an average and that's what we used, as well.

Now, on the diesel side this is a little bit more clear cut. Now, they only have an excise tax. I'm not quite clear why the break out on the gasoline side actually happened. But on the diesel side there has been changes to the excise taxes that happen every July 1st. But for this particular year, from June 30th to July 1st, the same 16 cents will be the same in both periods.

That being said, as part of the 2010 changes what they did on the diesel side is they did reduce the excise tax for diesel and they increased the sales tax. So, most of the revenue is on the sales tax side for the diesel.

Now, on November 1st, though, there will be a 20-cent increase from 16 cents up to 36 cents excise tax. There will also be an increase to the sales tax of 4 percentage points, from 10 percent all the way up to 14 percent.

Now, there's likely not going to be any changes between then or at least the law doesn't say there will be. But again, like gasoline, starting in 2020 that 36 cents will be multiplied by the Department of Finance's CPI to account for inflation moving forward, and every year will be increased from that moment forward.

Now, considering how complex that was, and I'm almost out of breath just talking about it, is there any questions on that, to give myself a chance to get a breath?

COMMISSIONER SCOTT: I do not. But it was helpful to have the pre-brief.

MR. EGGERS: All right. Now, moving on from excise tax to the Low Carbon Fuel Standard, here are our adder forecasts for the Low Carbon Fuel Standard for

both gasoline and diesel.

These particular adder forecasts are based on a credit price forecast, which will be outlined in our upcoming report. And, unfortunately, I didn't have time to go through all of them. But basically what you're seeing here is in our high credit price forecast. We have our credit adder going up to roughly about 21 cents a gallon, and then falling down a little bit.

And the assumption here is that the percent reduction in carbon intensity will remain constant from 2020 on. And then from 2020 on, it will become a little bit easier as new low carbon fuels are incentivized and thus bringing the credit price down. Then, it will be easier to comply moving forward and thus the price will come down.

Now, you see the same sort of motion in the mid credit price. In this particular case it rises up to roughly about 15 cents and then starts coming down. The same sort of assumption is happening in this particular occurrence.

And then in the low credit price case we just assume that, for whatever reason, low CI product very easily made it to California and thus there's no need to have the credit price lower, and thus the cost implications are much, much lower, and thus roughly

about 7 cents a gallon for gasoline moving forward.

And we see the same sort of look over on the diesel side. Again, this is because it's a result of the credit price forecast that we particularly used.

And the assumption there is that the credit price would equal, basically, the marginal price for mitigation in the LCFS program. And thus, it would be directly passed on to the consumer based on the 10 percent mitigation.

Okay. Now, getting into our gasoline margins, when we're looking at gasoline margins there's two margins we tend to be concerned with when it comes to gasoline and diesel. The first being the refiner margin, which are the green bars on this particular chart. The other one is the retail margin, which is the orange bars on this particular chart.

Now, in the 2017 forecast, the mid-price case was basically just an average of the entire 2003 to 2016 period of both the refiner margins and the retailer margins on the very bottom. And these are represented by the solid red line and the solid black line below.

That being said, as you can very clearly see from 2012 to 2016 there has been a noticeable rise in retail margins here, in California. And the high price case basically captures that. And, basically, the

increase in the margin really comes from those increases in retail margins, even though there are worse, slightly increases in refiner margins during that particular time period.

Our low price case is basically the 2008 to 2011 average for both refiner and retailer margins. In this particular case this was a nice period that had both low retailer margins and refiner margins. And, really, is more a lower cost because of the very noticeably low refiner margins.

Now, a little bit of these time periods are cherry picked, and I only say that because they were cherry picked in order to conform with both diesel and jet fuel, as well, because I wanted to stay in consistent time periods when choosing these margins.

And as you can see here, on the diesel side, basically the same sort of dynamics are happening on the diesel side as they were happening on the gasoline side.

Here, the blue bars are the refiner margins for diesel, and the yellow/orange are the retailer margins. And we're seeing a lot of the same sort of shape in the margins on the diesel side, as we saw on the gasoline. With a couple noticeable exceptions being the 2008. For whatever reason, diesel margins were able to stay very noticeably high in 2008, where gasoline very quickly

fell.

That being said, the same sort of relationships in the margin sort of relationships did stay the same. So, the high price cases do represent a time of a little bit higher than normal refiner margins and every noticeably higher retailer margins. Where the low case was a time period of lower than normal refiner margins and roughly lower than normal retail margins, as well.

So, what all this means is here are the actual numbers that we used in order to create the actual gasoline, diesel, and jet fuel prices. The margins here are that first column over on the left, in the case of the mid case. It worked out from a crude to retail margin of 87.9 cents. We then add the proper taxes, including a 2-cent underground storage tank, then we multiplied it by the tax rate mentioned earlier. The same sort of methodology for both diesel and gasoline.

We did also include a Cap and Trade adder, which is basically the Cap and Trade price that was the same one that was used by our procurement and modeling unit for electricity generation. So, it is consistent with other modeling work done in the California Energy Commission.

I didn't go into jet fuel prices, but there are calculations done for them, and you can see what those

margins were below. The thing with our jet fuel prices is those jet fuel prices do represent a common carrier price for jet fuel. Thus, no state or federal taxes do apply to those jet fuel prices and none were added.

All of this basically cooks out to gasoline in the high case starting at around $4.00 a gallon in 2017, and then rising all the way to $7.50 by 2030 in the high case.

As one would expect, diesel is much more expensive or is more expensive than gasoline in all particular cases, and thus the dotted line is higher in the high case.

Gasoline in the mid case starts at a little bit under $3.00 and then steadily rises to roughly about $4.50 by 2030, in our mid-price case.

In our low price case, in 2017 gasoline per gallon is $2.00 a gallon and then slowly rises to 2030, to about $2.50.

That being said, with the fixed margin structure a lot of the relationships between gasoline, diesel and jet fuel always pretty much stay the same, and there's not a lot of crisscrossing because of it.

Now, that does change a little bit here when we talk about E-85 prices and transportation propane prices. In order to come up with a price projection

methodology for these two prices, which is outlined more clearly in our report, we had to sort of scrap the margin methodology because a percentage relationship was something we were seeing as a better fit within the data.

And to get data on both E-85 prices and propane prices were what we used was Clean Cities posted prices, which is the program by the Department of Energy, through the United States of America, which they have posted prices for E-85 and all alternative and renewable transportation fuels for the Nation, as a whole. And we were able to contact them and get California-specific prices when we did our analysis.

And in the case of E-85, we also look at prices from e85.com to see if they were relatively similar, and in both cases they were.

And what we saw is the sort of normal relationship between gasoline and E-85 was basically the gasoline price divided by 1.26 would get you an E-85 price. And this was sort of the normal relationship between gasoline and diesel. And that works out to about a 15 percent difference between the two.

And in order to be a GGE or equivalent on a gasoline gallon, or energy content basis, you would need to divide the gasoline price by 1.3. So, in both our

mid and low case E-85, on an energy content basis, is actually more expensive than gasoline. Only in our high case does E-85 become price competitive with gasoline.

And when we brought this up with Propel, this was something that they also confirmed on their end that this was their current pricing methodology. Because what they were seeing is people were willing to pay a little bit of a premium for E-85, for it being a renewable fuel. Thus, they were not pricing at price equivalency. So, we did carry that particular relationship moving forward within our price cases.

Now, in the case of propane, propane prices on the transportation side seemed to match refiner acquisition costs or the price of crude oil a little bit more closely. That being said, we have a 1.6 multiplier to the crude oil price for our propane and 1.79 for the high case, and a 1.38.

And this particular relationship does change how propane relates to gasoline in the different cases. And what I'm talking about here is in the high case the propane price, which is very much here on the top, is very much more expensive than gasoline on a per-gallon basis.

E-85 keeps it very close or a very standard relationship with gasoline in the high case.

Now, here in the mid case the dotted line, which is the propane, starts out lower then becomes more expensive than gasoline on a per-gallon basis from about 2025 onward.

In the low case, propane is always less expensive than gasoline on a per-gallon basis.

Now, what you'll also notice is the gap between gasoline and E-85, as we go down on the different price forecasts it does become closer and closer. And a little bit of that is because you've got a lower price in gasoline, you also have a smaller divider, if you will, to create the E-85 price.

Now, moving on to transportation CNG and LNG. In this particular case we do not use crude oil as our sort of base forecast in order to create a final price. Here we actually utilize the Natural Gas Unit, in the Supply Analysis Office. We actually used their Henry Hub price cases that were developed for the IEPR, so they are consistent with work that is being done on that side of the aisle.

We then created -- we used the same sort of margin methodology that we used in gasoline and diesel. Here, we used PG&E tariff price information and Clean Cities information in order to come up with some therm margin differences.

In the case of the difference between Clean Cities and PG&E, they were so close that we actually ended up relying more on the PG&E tariff prices because we had a longer run of information.

So, I think in the case of the CNG price it would be the calculation is straight forward. We take the Henry Hub price; we add the margin, and then the appropriate taxes.

Then, when we get to an LNG price we would then divide the CNG price by the -- or, the CNG GGE price, and divide it by 1.14 because according to the Clean Cities information LNG was being discounted relative to CNG. Likely, in order to increase its penetration in the market, but that was the relationship we saw, and so that was got modeled into the forecast.

In the case of the mid case, the margin was $1.30 per therm. In the high cases, $1.65 per them. And in the low case it was $1.13 per them. That being said, because we have such low natural gas prices going on in the U.S. right now, CNG and LNG are very much discounted relative to gasoline on a GGE basis.

In the case of gasoline -- or, in the case of CNG, in the high case it starts just above $3.00 and rises just above $4.00 in 2030. Where the gasoline price starts at $4.00 in 2017 and then rises all the way

up to roughly $7.50 by 2030.

In the case of the mid case gasoline, a little bit under $3.00, it rises to a little bit above $4.00. CNG here, again, a little bit closer in this particular case. It's about $2.50 here, in 2017. But it's fairly flat over the forecast period and only rises to roughly about $3.30 by 2030.

All these relationships are very close together in the low case.

Finally, to wrap up before I lose my voice here, and I apologize, I'm battling a little bit of a cold, in the case of the electricity prices we basically used the same electricity prices that are used in our electricity demand forecast. In this case it was the residential rate. We are doing additional work to try to figure out if there is additional information for a retail electricity rate that we could possibly use, but that work is still ongoing.

In the case of hydrogen, the hydrogen prices are from the same NREL team that is developing the AB8 report. And, basically, they develop the same price projections that we are using that were presented earlier. And since I didn't, or since my staff didn't do either of those, I don't have any sort of presentation on what those actual numbers are.

So, if there are any questions, I'd be happy to take them right now.

MR. SCHREMP: Yeah, Ryan, this is Gordon. I have a quick question for you. Have you, I know that you're taking into account carbon market cost increases on the fuels for, say, gasoline and diesel. Have you also done that for your liquefied natural gas forecast or you haven't incorporated any of those, yet?

The only reason I ask is for fuels under the CAP, LNG actually does have a fee associated with it.

MR. EGGERS: No. I'm glad you brought that up, Gordon. Cap and Trade was not included in both the CNG and LNG prices, but that is something we can incorporate moving forward.

MR. SCHREMP: Okay, thank you.

COMMISSIONER SCOTT: Great, thank you very much, Ryan.

We'll now to our public comment portion. I do not have any blue cards up here with me, indicating public comment in the room.

But let me just ask, is there anyone in the room who would like to make a public comment? If so, please come on up to the mic and we're listening.

Okay, let me turn to our WebEx to see whether or not we have any public comments there?

MS. RAITT: No comments on WebEx.

COMMISSIONER SCOTT: No comments on WebEx. All right, well then let me, as Heather's pulling up the information about how to get your comments in, just say thank you so much to everyone today. I thought it was a series of really thoughtful and informative presentations. And you guys all gave really clear explanations of relatively complicated datasets and sets of information, so I appreciate that. Thank you for doing such great presentations.

And so, a special thanks to Ryan, to Gordon, to Dave, and to Adrian for their presentations today.

I do want to remind folks, who are interested stakeholders or commenters, to consider the question that Ryan asked in his earlier presentation about what types of data assessments can be replicated to the alternative and renewable fuels? That's something that we're very much looking forward to receiving your constructive comments on this question and, of course, any feedback that you have on the workshop.

I'd love to say thank you to our terrific IEPR team, who has these things running smoothly all of the time. Thanks for your great work.

And let me turn real quick to Heather, so she can go through next steps with folks.

MS. RAITT: Yeah, just to say that the written comments are due on July 20th, and all the information for how to submit comments is in the notice.

COMMISSIONER SCOTT: Great. So, have a good afternoon and with that, we're adjourned.

(Thereupon, the Workshop was adjourned at 4:25 p.m.)

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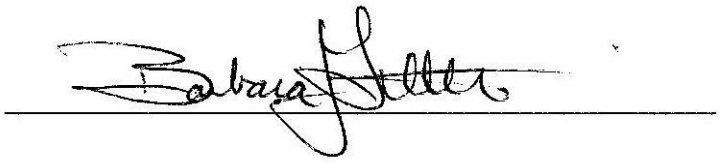

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