CBE Attachments 16 through 25

Attachment 16

Oil Refinery CO_2 Performance Measurement

Prepared for the

Union of Concerned Scientists

Technical analysis prepared by
Communities for a Better Environment (CBE)

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September 2011

File No. COMMBETTERENVFY11103

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Executive Summary

Statewide, oil refineries in California emit 19–33% more greenhouse gases (GHG) per barrel crude refined than those in any other major U.S. refining region.

For this report we gathered nationwide refinery data and new California-specific data to analyze refinery emission intensity in California. The goal of the analysis is to compare and evaluate the factors driving the relatively high emission intensity of California refineries.

Petroleum process engineering knowledge was applied to identify factors that affect refinery emission intensity. Data on these causal factors from observations of real-world refinery operating conditions across the four largest U.S. refining regions and California was gathered for multiple years. Those data were analyzed for the ability of the factors and combinations of factors to explain and predict observed refinery emission intensities.

This report summarizes our findings.

Crude feed quality drives refinery energy and emission intensities.

Making gasoline, diesel and jet fuel from denser, higher sulfur crude requires putting more of the crude barrel through aggressive carbon rejection and hydrogen addition processing. That takes more energy. Burning more fuel for this energy increases refinery emissions.

Differences in refinery crude feed density and sulfur content explain 90–96% of differences in emissions across U.S. and California refineries and predict average California refinery emissions within 1%, in analyses that account for differences in refinery product slates.

Analysis of other factors confirms that crude quality drives refinery emissions.

Total fuel energy burned to refine each barrel—energy intensity—correlates with crude quality and emissions, confirming that the extra energy to process lower quality crude boosts refinery emissions. Dirtier-burning fuels cannot explain observed differences in refinery emissions; the same refining by-products dominate fuels burned by refineries across regions.

Increasing capacity to process denser and dirtier oils enables the refining of lower quality crude and correlates with refinery energy and emission intensities when all data are compared, confirming the link between crude quality and energy intensity. But some of this “crude stream” processing capacity can be used to improve the efficiency of other refinery processes, which causes processes to emit at different rates, and process capacity does not predict refinery emissions reliably.

As refinery crude feed quality and emissions increase, gasoline, distillate and jet fuel production rates change little, and in some cases gasoline and distillate yield declines slightly. Product slates do not explain or predict refinery emissions when crude quality is not considered.

An ongoing crude supply switch could increase or decrease California refinery emissions depending on what we do now.

Ongoing rapid declines of California refineries’ current crude supplies present the opportunity to reduce their emissions by about 20% via switching to better quality crude—and the threat that refining even denser, dirtier crude could increase their emissions by another 40% or more.

Purpose, scope, and approach

We set out to identify the main factors driving the high carbon intensity of California's refining sector. This project evaluates factors that drive refinery emissions, so that one can identify opportunities for preventing, controlling, and reducing those emissions.

Analysis focuses on carbon dioxide (CO_2) emissions from fuels refineries in California. This reflects known differences between fuels refining and asphalt blowing*,* and the recognition that CO_2 dominates the total global warming potential of GHG (CO_2e) emitted by oil refining *(1–3)*. CO_2 emissions from fuels refining account for 98–99% of 100-year horizon CO_2e mass emitted by oil refining in California *(2, 3)*.

The scope includes emissions at refineries and from purchased fuels consumed by refineries. (Many refiners rely on hydrogen or steam from nearby third-party plants and electricity from the public grid; ignoring that purchased refinery energy would result in errors.) This focus excludes emissions from the production and transport of the crude oil refined and from the transport and use of refinery products. That allows us to isolate, investigate, and measure refinery performance.

At the same time, oil refining is a key link in a bigger fuel cycle. Petroleum is the largest GHG emitter among primary energy sources in the U.S., the largest oil refining country, and in California, the refining center of the U.S. West *(3–5)*. So the "boundary conditions" used here, while appropriate for the scope of this report, are too narrow to fully address the role of oil refining in climate change.

Analysis of key factors driving emissions is based on data from observations of refineries in actual operation. This approach differs from those that use process design parameters to generate data inputs, which are then analyzed in computer models constructed to represent refinery operations. This "data-oriented" approach avoids making assumptions about processing parameters that vary in real-world refinery operation. It also more transparently separates expected causal relationships from observations.

However, this approach is limited to available publicly reported data. We use a ten-year data set encompassing 97% of the U.S. refining industry that was gathered and validated for recently published work *(2)* as our comparison data. We had to gather and validate the California refinery data ourselves *(4, 6–30)*. The comprehensive six-year statewide data for California refining and facility-level 2008–2009 data we analyze are presented in one place for the first time here *(31)*.

A recently published study used national data to develop a refinery emission intensity model based on crude feed density, crude feed sulfur content, the ratio of light liquids to other refinery products, and refinery capacity utilization *(2)*. This report builds on that published analysis using California data.

For a more formal presentation of the analysis, the raw data, and data documentation and verification details, please see the technical appendix to this report.

Emissions intensity—higher in California

California refineries emit more CO_2 per barrel oil refined than refineries in any other major U.S. refining region.

Figure 1 compares California with other major U.S. refining regions based on emissions intensity—mass emitted per volume crude oil refined. Crude input volume is the most common basis for comparing refineries of different sizes generally *(4),* and it is a good way to compare CO_2 emissions performance among refineries as well *(2).*

Consider the *emissions* part of emissions-per-barrel for a moment. This measurement is fundamental to refinery emissions performance evaluation. We need to know where it comes from and if we can trust it.

The bad news: many refinery emission points are not measured. Instead, measurements of some sources are applied to other similar sources burning known amounts of the same fuels to estimate their emissions. This "emission factor" approach makes many assumptions and has been shown to be inaccurate and unreliable for pollutants that comprise small and highly variable portions of industrial exhaust flows. The best practice would directly measure emissions, and apply emissions factors only until direct measurements are done.

The good news, for our purpose here, is that the emissions factor approach is prone to much smaller errors when applied to major combustion products that vary less with typical changes in combustion conditions, like CO_2. This means that in addition to being the best information we have now, the emission factor-based "measurements" we use here for CO_2 *(2, 8, 30, 31)* are relatively accurate as compared with some other refinery emissions "measurements" you might see reported.

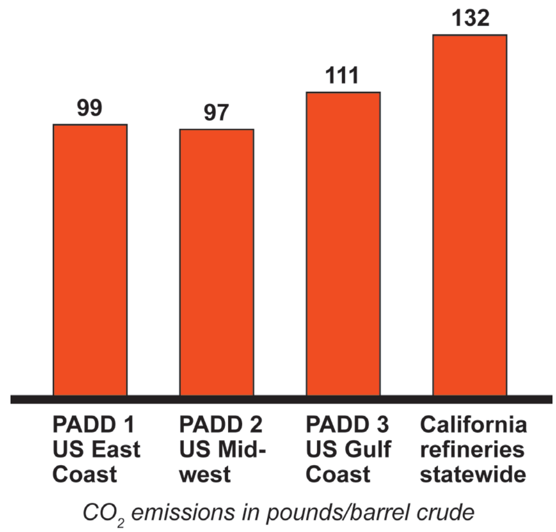


Figure 1. Average refinery emissions intensity 2004–2008, California vs other major U.S. refining regions. Emissions from fuels consumed in refineries including third-party hydrogen production. PADD: Petroleum Administration Defense District.

Data from Tech. App. Table 2-1 *(31).*

Thus, the substantial differences in refinery emissions intensity shown in Figure 1 indicate real differences in refinery performance. They demonstrate extreme-high average emissions intensity in California. They suggest that other refineries are doing something California refineries could do to reduce emissions. The big question is what *causes* such big differences in refinery emissions.

Energy intensity—the proximate cause of high emissions intensity

California refineries are not burning a dirtier mix of fuels than refineries in other U.S. regions on average. Their high emissions intensity comes from burning more fuel to process each barrel of crude. During 2004–2008 refineries in California consumed 790–890 megajoule of fuel per barrel crude refined, as compared with 540–690 MJ/b in other major U.S. refining regions (PADDs 1–3) *(31)*.

This is consistent with recent work showing that increasing energy intensity that causes refineries to consume more fuel, and not dirtier fuels, increases emissions intensity across U.S. refining regions *(2)*. Increasing fuel energy use per barrel crude refined—increasing energy intensity—is the proximate cause of increasing average refinery emissions intensity.

Looking at where refineries get the fuels they burn for energy helps to explain why energy intensity, and not dirtier fuel, drives the differences in refinery emissions intensity we observe.

The fuel mix shown for California refineries in Figure 2 is dominated by refinery fuel gas, natural gas, and petroleum coke just like in other U.S. refining regions. Coke and fuel gas burn dirtier than natural gas but are self-produced, unavoidable by-products of crude oil conversion processing that are disposed or exported *(32)* to be burned elsewhere if refineries don't burn them. Natural gas is brought in when refinery energy demand increases faster than coke and fuel gas by-production. The net effect is that emission per MJ fuel consumed does not change much as refinery energy intensity increases and demands more fuel per barrel processed.

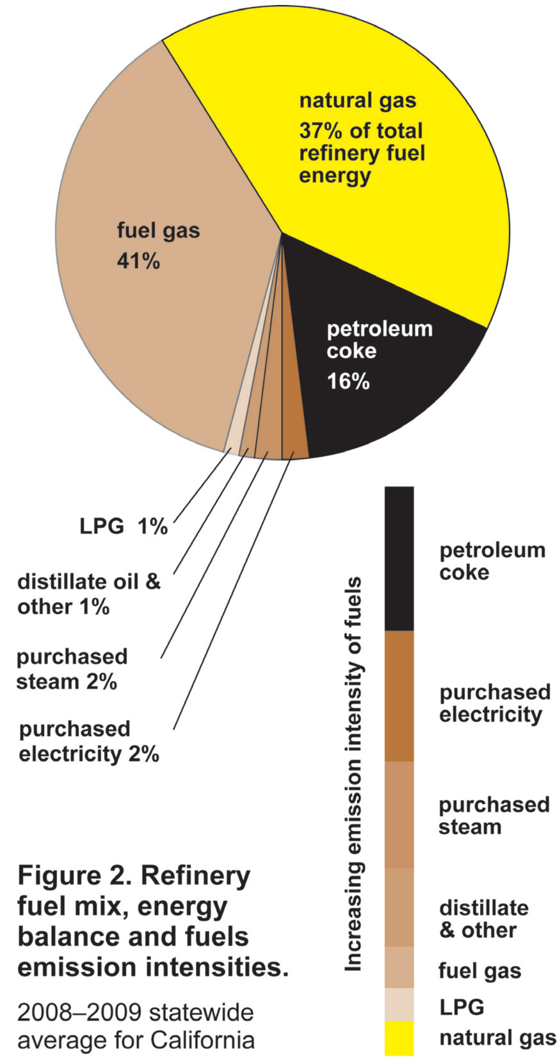


Figure 2. Refinery fuel mix, energy balance and fuels emission intensities.

2008–2009 statewide average for California

Data from Tech. App. *(31)*.

The root cause—making motor fuels from low quality crude

Making motor fuels from denser, more contaminated crude oil increases refinery energy intensity.

A hundred years ago the typical U.S. refinery simply boiled crude oil to separate out its naturally occurring gasoline (or kerosene) and discarded the leftovers. Not any more. Now after this “distillation” at atmospheric pressure, refineries use many other processes to further separate crude into component streams, convert the denser streams into light liquid fuels, remove contaminants, and make many different products and by-products from crude of varying quality *(1, 2)* But even complex refineries still make crude into motor fuels by the same steps: separation; conversion; contaminant removal, product finishing and blending.

The middle steps—conversion, and removal of contaminants that poison process catalysts—are the key to the puzzle.

Making light, hydrogen-rich motor fuels from the carbon-dense, hydrogen-poor components of crude requires rejecting carbon and adding hydrogen *(1, 2, 16, 25)*. This requires aggressive processing that uses lots of energy. Refiners don’t have to make gasoline, diesel and jet fuel from low quality crude, but when they decide to do so, they have to put a larger share of the denser, dirtier crude barrel through energy-intensive carbon rejection, hydrogen addition, and supporting processes. That aggressive processing expands to handle a larger share of the barrel even when the rest of the refinery does not.

Figure 3 illustrates this concept: Refineries A and B make fuels from the same amounts of crude but Refinery B runs low quality crude. Their atmospheric distillation capacities are the same, but more of the low quality crude goes through expanded carbon rejection and aggressive hydrogen addition processing at Refinery B. The extra energy for that additional processing makes Refinery B consume more energy per barrel refined.

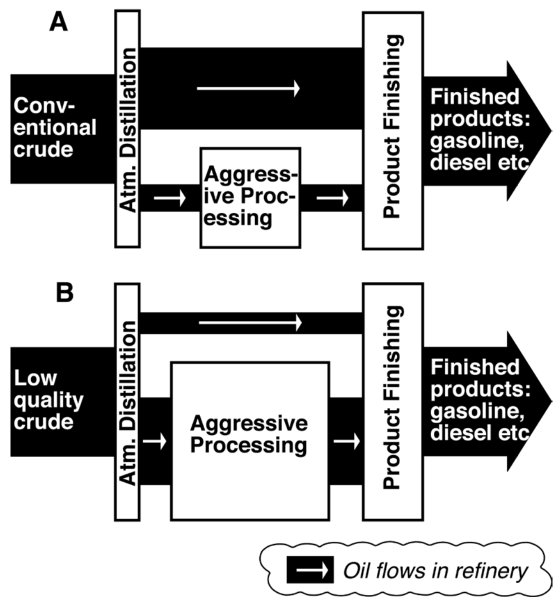


Figure 3. Simple refinery block diagram. Aggressive processing (vacuum distillation, cracking, and aggressive hydroprocessing) acts on a larger portion of the total crude refined to make fuels from low quality crude. Figure reprinted with permission from Communities for a Better Environment.

In fact, as crude feed quality worsens across U.S. refining regions, the average portion of crude feeds that can be handled by refiners’ vacuum distillation, conversion and aggressive hydrogen addition processes combined increases by more than 70%, from 93–167% of refiners’ atmospheric crude distillation capacity *(31)*.

California refineries have more of this aggressive processing capacity on average than refineries in any other U.S. region. Of the five major "crude stream" processes that act on the denser, more contaminated streams from atmospheric distillation (vacuum distillation, coking, catalytic cracking, hydrocracking, and hydrotreating of gas oil and residua), California refineries stand out for four. *(Figure 4.)* Meanwhile, consistent with the example described above, average California product hydrotreating and reforming capacities are similar to those of other U.S. refining regions.

Vacuum distillation boils the denser components of crude in a vacuum to feed more gas oil into carbon rejection and hydrogen addition processing. Conversion capacity (thermal, catalytic and hydrocracking capacity) breaks denser gas oil down to lighter motor fuel-type oils. Hydrocracking and hydrotreating of gas oil and residua are aggressive hydrogen addition processes. They add hydrogen to make fuels and remove sulfur and other refinery process catalyst poisons.

This aggressive hydroprocessing uses much more hydrogen per barrel oil processed than product hydrotreating *(25)*, especially in California refineries *(Fig. 5)*. That is important because refiners get the extra hydrogen from steam reforming of natural gas and other fossil fuels at temperatures reaching 1500 ºF, making hydrogen plants major energy consumers and CO_2 emitters *(2, 26, 28, 29, 33, 37)*.

Hydrogen production increases with crude feed density and hydrocracking rather than product hydrotreating across U.S. refineries *(2)*, and is higher on average in California than in other U.S. regions *(31)*.

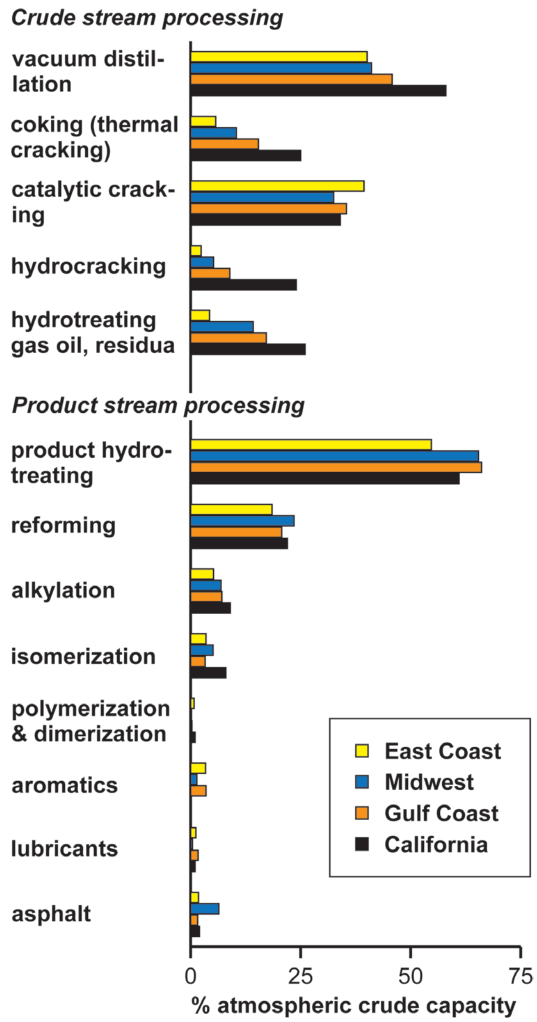


Figure 4. Refinery process capacities at equivalent atmospheric crude capacity, PADDs 1–3 and California (5-yr. avg.) *(31).*

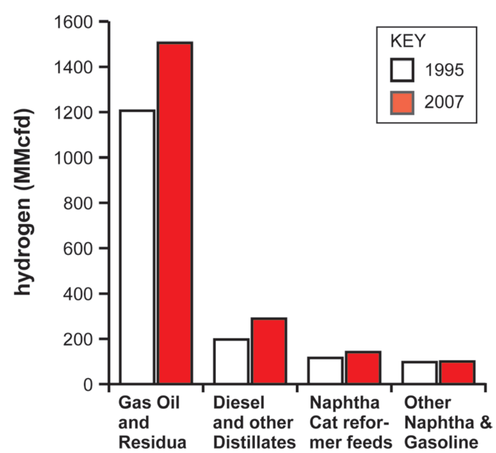


Figure 5. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007. Figure from CBE *(33)*.

Observations of operating refineries across the U.S. and California reveal the impact of crude quality on refinery energy and emission intensities. Crude feed density increases from Midwest Petroleum Administration Defense District (PADD) 2 on the left of Figure 6 to California on the right. Refinery energy intensity increases steadily with crude feed density. Crude stream processing capacity also increases with crude density, reflecting the mechanism by which refineries burn more fuel for process energy to maintain gasoline, diesel and jet fuel yield from lower quality oil. As a result, refinery output of these light liquid products stays relatively flat as crude density increases.

Figure 7 shows comparisons of the same nationwide data using nonparametric analysis to account for potential nonlinear relationships among causal factors. Crude feed density (shown) and sulfur content (not shown) can explain 92% of observed differences in refinery emissions (Chart A). Together with the light liquids/other products ratio, crude feed density and sulfur content can explain 96% of observed differences in emissions (Chart B). Increasing crude stream processing capacity (Chart C) confirms the mechanism for burning more fuel energy to process denser, higher sulfur crude.

The ratio of light liquids to other products does not explain refinery emission intensity (Chart D). This is consistent with recently published work showing that the products ratio was not significant in the strong relationships among refinery energy intensity, processing intensity, and crude quality *(2)*. Differences in refinery products alone cannot provide an alternative explanation for the large differences in refinery emissions that are observed.

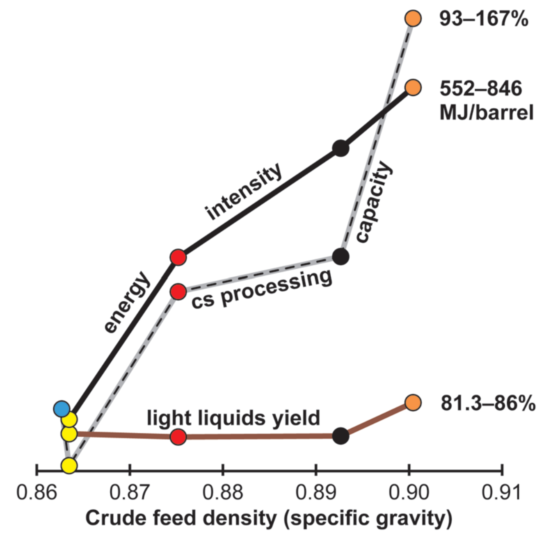


Figure 6. Average energy intensity (MJ/b), crude stream processing capacity (% atm. distillation capacity), and light liquids yield (% crude) by refining region. East Coast PADD 1, 1999–2008 (yellow). Midwest PADD 2, 1999–2008 (blue). Gulf Coast PADD 3, 1999–08 (red). West Coast PADD 5, 1999-2003 (black). California, 2004–2009 (orange). Data from Tech. App. Table 2-1.

But the same differences in product slates that affect emissions only marginally (compare charts A and B) may be more strongly related to processing capacity. PADDs 1 and 5 produce less light liquids than other regions that refine similar or denser crude (compare charts B and D), which should require marginally less crude stream processing capacity in PADDs 1 and 5. Consistent with this expectation, PADD 1 and PADD 5 data are shifted to the left in Chart C relative to their positions in Chart A. Conversely, California maintains light liquids production despite refining denser crude than that refined elsewhere, and the California data are shifted to the right in Chart C. These shifts are independent from any similarly large difference in observed emissions—the data shift horizontally while emission intensity changes verti-

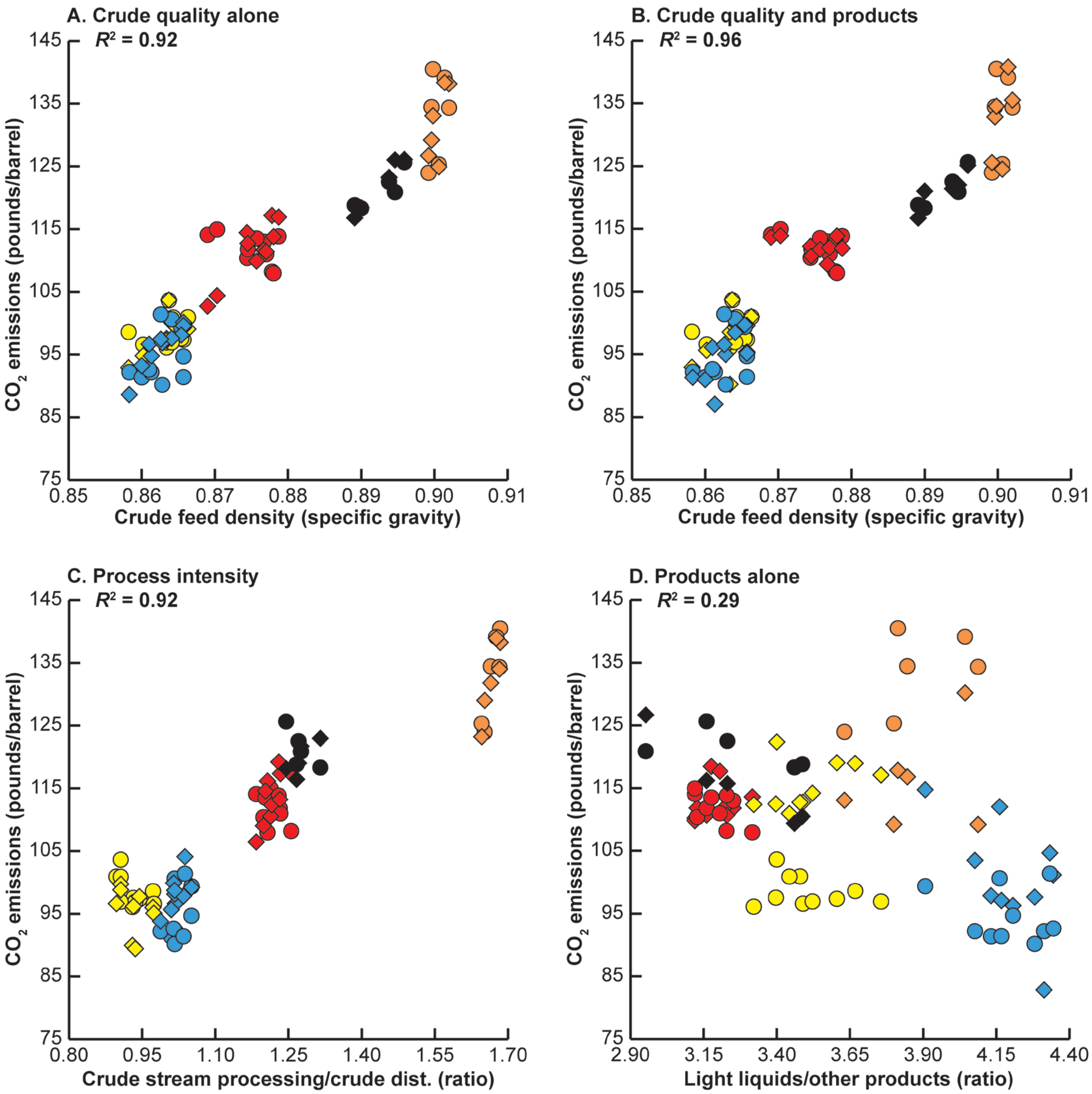


Figure 7. Comparison of refinery emission intensity drivers. Results from nonparametric regression analyses comparing emission intensity with crude feed quality (density, shown; and sulfur, not shown; see Chart A); crude quality and light liquids/other products ratio (B); crude stream processing capacity (C); and products ratio (D). All comparisons account for refinery capacity utilization. Circle [diamond]: annual average observation [prediction] for PADD 1 1999-2008 (yellow), PADD 2 1999–2008 (blue), PADD 3 1999–2008 (red), PADD 5 1999–2003 (black), and California 2004–2009 (orange). Data from Technical Appendix tables 2-1, 2-10.

cally in Chart C—so that at least some of the differences in process capacity do not reflect real differences in emissions.

Thus, observations of operating refineries across U.S. regions and California demonstrate the impact of crude quality on refinery CO_2 emission intensity. However, while it can enable the refining of lower quality crude, processing capacity does not equate to emissions intensity, because it can be used in different ways to target different product slates, which could require different process energy inputs, and thus emit at different rates.

Drivers of refinery CO_2 intensity: assessing correlations

The petroleum process engineering logic and comparisons of refineries in real-world operation documented above suggest the following model for interactions of the major factors affecting refinery CO_2 emission intensity:

- Making lower quality crude into light liquid fuels consumes more energy and this increases refinery emissions.
- Differences in fuels product slates alone cannot explain differences in emissions when crude quality is not considered. However, light liquids yield that is high or low relative to crude feed quality may reflect differences in crude stream processing capacity and its relationship to energy and emission intensities.
- Crude stream processing capacity can be used to refine lower quality crude, make more light liquid fuels from crude of a given quality, and/or treat other process feeds. Different uses of this processing capacity may consume energy and emit CO_2 at different rates.

If this model is correct, crude quality and fuels products should be able to predict refinery emission intensity. Further, crude quality and products should predict emission intensity better than either refinery products or processing capacity alone. The following analyses test this hypothesis by predicting California refinery emissions based on U.S. refinery data.

Unlike the comparison analyses shown in Figure 7, these predictive analyses use all of the U.S. data and only some of the California data: the California refinery energy and emission intensity observations are withheld. Because the resultant analyses do not "know" the California emissions that are actually observed, their results represent true predictions of California refinery emissions. Those predictions can then be compared with the emissions actually observed to test the ability of products output, process capacity, and crude quality along with products, to predict California refinery emissions.

This model is taken from previously published work that showed crude quality and fuels produced resulted in reasonably accurate predictions *(2)*. However, the new California data analyzed for the first time here reveal new extremes of high crude feed density, crude stream processing capacity, and refinery energy and emission intensities *(31)*. At the same time, while light liquids yields and crude stream processing capacities are slightly lower relative to crude feed density among some of the previously analyzed U.S. data, those yields and capacities are slightly higher in California. *(Discussion of Fig. 7 above.)* For all of these reasons its ability to predict California refinery emissions based on the nationwide data represents a good test of this model.

Refinery products alone

Total light liquids yield varies little *(Figure 6)* and the light liquids/other products ratio cannot explain differences in refinery emissions *(Figure 7)*. However, gasoline, distillate diesel, and kerosene jet fuel are made in different ways that may consume energy and emit at different rates *(16, 28, 33–38)*. Analyzing differences in the relative amounts of individual fuels produced instead of only their lump-sum could provide more information about the relationship of refinery products and emissions. Therefore we test whether the mix of gasoline, distillate, and kerosene jet fuel produced—the "fuels products mix"—can predict refinery emissions.

U.S. refinery emissions line up with the mix of fuels produced but *decrease* as the portion of refinery emissions caused by differences in fuels produced *increases* (compare charts A and B in Figure 8). This counter intuitive result is caused by decreasing gasoline and distillate yields as crude feed density increases *(2)* that are reflected in lower light liquid yields as emissions increase among U.S. PADDs *(Figure 7)*. In addition, consistent with the small differences in yields shown in Figure 6, the range of emissions from differences fuels products yields (~10 lb/b) is small compared with that of observed refinery emissions (~50 lb/b; Chart 8-B).

Observed California refinery emissions exceed those predicted based on the fuels products mix by 15–31% annually and by a six-year average of 22%. This prediction error results from equating California to other regions that have a similar mix of fuels yields but lower refinery emissions. These results show that fuels product slates cannot explain or predict refinery emissions when crude quality is not considered, further supporting effects of crude quality on refinery emissions.

Processing capacity alone

This analysis tests the ability of crude stream processing capacity—equivalent capacities for vacuum distillation, conversion (thermal, catalytic and hydrocracking), and gas oil/residua hydrotreating relative to atmospheric crude distillation capacity—to predict refinery emissions. Although products processing or refinery wide processing equivalent capacities provide alternative measurements of refinery "complexity" *(Figure 4),* crude

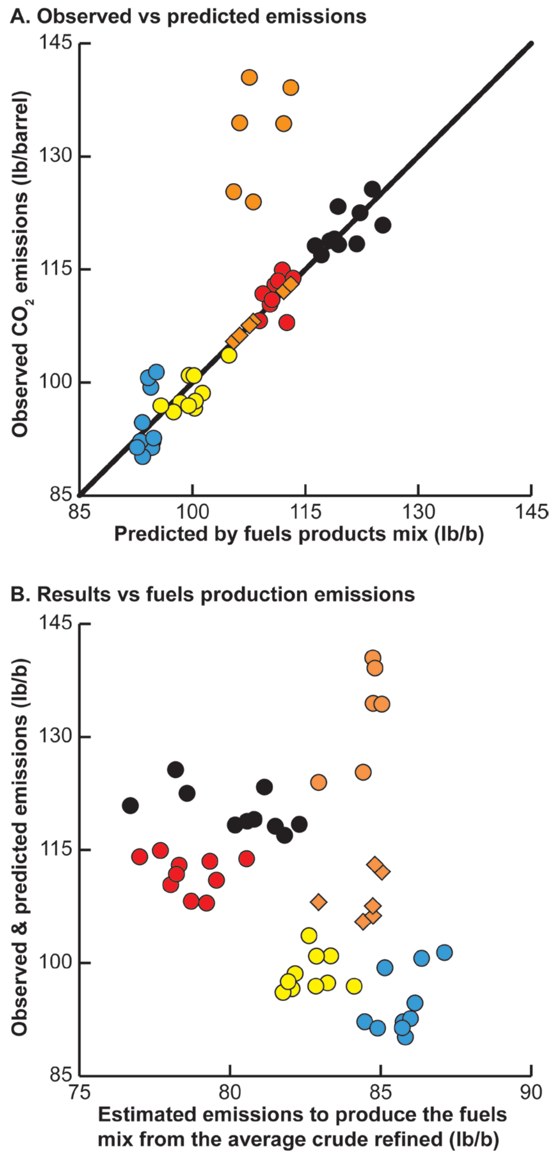


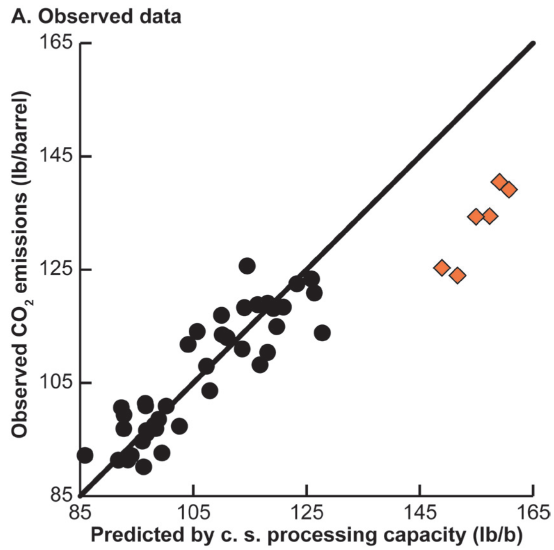
Figure 8. Refinery emission intensity vs gasoline, distillate, and kerosene jet fuel yields. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.94). Circle [diamond]: annual average observation [prediction] for PADD 1 (yellow), 2 (blue), 3 (red), 5 (black), or California (orange). Differences in the mix of these products among U.S. PADDs correlate with refinery emissions (Chart A) that cannot be explained by emissions from producing the products alone (Chart B) and do not predict California refinery emissions. Gasoline, distillate, and kerosene production CO_2 estimates (46.0, 50.8, 30.5 kg/b respectively) from NETL *(28).* All other data from Technical Appendix tables 1-5, 2-1.

stream processing capacity enables refining of lower quality crude and explains refinery energy and emission intensities when all data are compared while products processing and refinery wide capacities do not *(2, Figure 7, Tech. Appendix).*

Chart A in Figure 9 shows results for the prediction of California refinery emission intensity based on crude stream processing capacity. Although it can explain differences in emissions *(observed PADDs emissions included in analysis),* the prediction based on crude stream processing alone *(observed California emissions excluded from analysis)* exceeds observed emissions by 13–22% and by a six-year average of 17%.

This prediction error can be explained by refiners using processing capacity in different ways. In California, equivalent capacities for coking, hydrocracking and gas oil/residua hydrotreating exceed those of other U.S. regions *(Figure 4),* and total crude stream processing capacity exceeds atmospheric distillation capacity by an average of 67% *(Figure 6),* indicating uniquely greater capacity for serial processing of the same oil in multiple crude stream processes. That serial processing can alter the composition of feeds to various processing units, which can alter process reaction conditions, firing rates, and resultant fuel consumption and emission rates.

For example, gas oil hydrotreating capacity adds hydrogen to the H_2-deficient gas oil from vacuum distillation and removes contaminants from the oil that otherwise interfere with processing by poisoning catalytic cracking and reforming catalysts, thereby also removing those contaminants from unfinished products *(2, 16, 25).* In these ways, inserting more gas oil hydro-



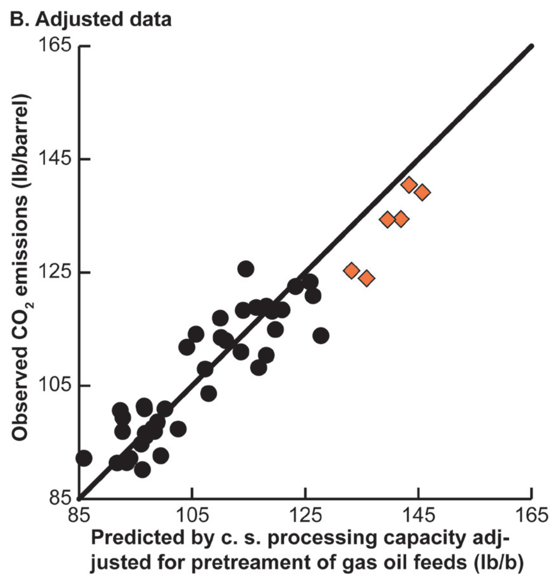


Figure 9. Emission intensity vs vacuum distillation, conversion, and gas oil/residua hydrotreating equivalent capacities. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.92). Black circle [orange diamond]: annual avg. for PADD 1, 2, 3 or 5 [California]. Chart A: Prediction based on observed data. Chart B: Identical to Chart A analysis except that California gas oil hydrotreating data are replaced by the lowest equivalent capacity observed among all these regions and years. Hydrotreating gas oil can improve other process efficiencies, so Chart B shows a plausible hypothetical example of why process capacity does not predict California emissions. Data from Tech. App. tables 1-3, 2-1.

treating in the middle of their crude stream processing trains helps refiners make more fuels product from denser and dirtier crude while improving downstream processing efficiency and reducing the need to treat product streams in order to meet "clean fuels" standards.

Thus, California refiners' very high gas oil hydrotreating capacity *(Figure 4)* is consistent with their abilities to maintain fuels yield despite denser crude and meet California fuel standards despite product hydrotreating and reforming capacities similar to those elsewhere *(figures 4, 7)*.

And because improved efficiencies from better cracking and reforming feed pretreatment may offset emissions from this additional gas oil hydrotreating, that may help explain why, relative to other refining regions, average refinery emission intensity does not increase as much as crude stream processing capacity in California.

Chart 9-B explores this plausible explanation. It shows results from the same analysis as Chart 9-A except that observed California gas oil hydrotreating capacity is replaced by the lowest U.S. crude stream hydrotreating capacity observed. Those adjusted California data thereby predict California emissions for the assumed scenario described above, where California gas oil hydrotreating capacity would not increase refinery emissions because its emissions are offset by efficiency improvements in downstream cracking and reforming processes.

In this hypothetical scenario, the prediction based on "adjusted" crude stream process capacity exceeds observed California refinery emissions by a six-year average of 5%, as compared with the 17% average error shown in Chart 9-A.

This hydrotreating example cannot exclude other differences in crude stream processing configuration or usage as causes of the prediction error shown in Chart 9-A. Indeed, the lack of publicly reported data for specific process units that makes it difficult or impossible to verify exactly how much each specific difference in processing changes emissions *(12, 28, 34)* is another reason why processing capacity alone is not a reliable predictor of refinery emission intensity.

These results support our hypothesis by showing that the ability to use crude stream processing in different ways, which can consume energy and emit at different rates, can explain the poor prediction of California emissions based on observed processing capacity alone.

Crude quality and fuels produced

Recently published work found that crude feed density, crude feed sulfur content, the ratio of light liquids to other products, and refinery capacity utilization[1] explain observed differences in energy and emissions intensities among U.S. refining regions and predict most of the differences among various government estimates of refinery emissions *(2)*. To test our hypothesis, we predict California refinery emissions based on this crude quality and products model *(2)* using all the U.S. data but only the California crude quality, products, and capacity utilization data.

In addition to the statewide data included in all our analyses, available data allow analysis of individual San Francisco Bay Area refineries. Reported crude feed data are too limited for such facility-level analysis of other California refineries.

[1] Capacity utilization is included as an explanatory factor in all the predictive analyses (figures 8–10).

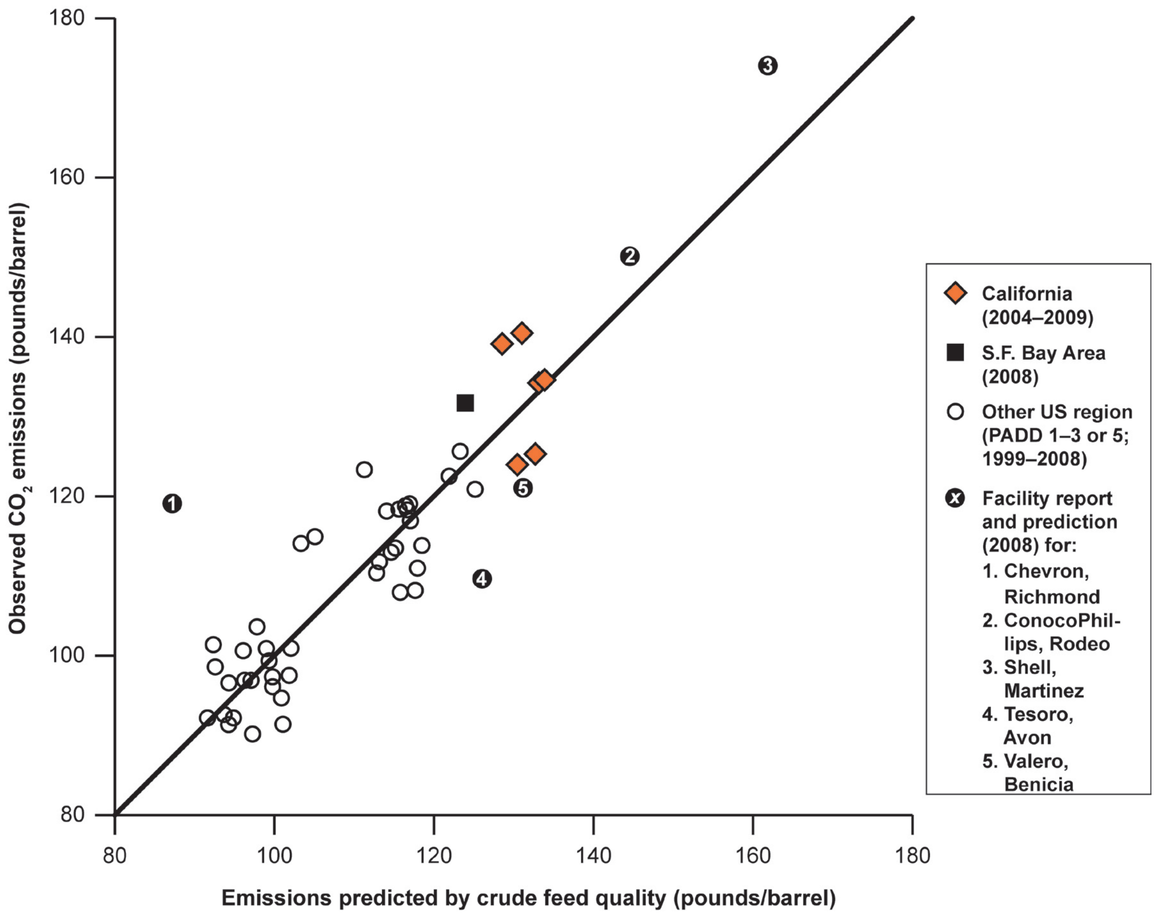


Figure 10. Refinery emission intensity vs crude feed density, sulfur content and light liquids/other products ratio. Predictions for California by partial least squares regression on U.S. data (R^2 0.90). Chart legend identifies annual average data. Data from Tech. App. tables 1-1, 2-1.

The diagonal line in Figure 10 shows the prediction defined by applying this model to the nationwide refinery data. Consistent with our hypothesis, the model tells us to expect increasing emissions intensity as crude feed density, sulfur content, or both increase. Observed emissions fall on or near the line in almost every case. California statewide refinery emissions range from 6% below to 8% above those predicted and are within 1% of predictions as a six-year average. San Francisco Bay Area refinery emissions exceed the prediction by 6%. Emissions reported by four of the five individual Bay Area refineries fall within the confidence of prediction when uncertainties caused by lack of facility products reporting are considered, and range from 13% below to 8% above the central predictions for these facilities.

The only data point that is clearly different from the emissions predicted by this model is for the Chevron Richmond refinery, and that result was anticipated as Chevron has reported inefficiency at this refinery. A 2005 Air Quality Management District permit filing by the company *(39)* cited relatively antiquated and inefficient boilers, reformers, and hydrogen production facilities at Richmond.

These results show that the crude quality and products model is relatively accurate and reliable for California refineries.

Crude supply is changing now

California refineries can and do import crude from all over the world *(24),* but their historically stable crude supply sources in California and Alaska are in terminal decline *(40–42).* This is driving a refinery crude switch: foreign crude imports were only 6% of the total California refinery crude feed in 1990; in 2009 they were 45% of total California crude feed *(21).* By 2020 roughly three-quarters of the crude oil refined in California will *not* be from currently existing sources of production in California or Alaska *(41, 42).*

An urgent question is whether, by 2020, California will switch to alternative transportation energy, or switch to the better quality crude now refined elsewhere, or allow its refiners to retool for a new generation of lower quality crude.

The model developed from analysis of nationwide refinery data that is validated for California refineries in this report predicts that a switch to heavy oil/natural bitumen blends could double or triple U.S. refinery emissions *(2).* Based on this prediction, replacing 70% of current statewide refinery crude input with the average heavy oil *(19)* could boost average California refinery emissions to about 200 pounds/barrel crude refined.[2] This would represent an increase above observed 2009 statewide refinery emissions of approximately 44% or 17 million tonnes/year.

Based on the same prediction model *(2),* and the average California refinery yield, fuels, and capacity utilization observed 2004–2009 *(2, 31),* replacing 70% of current statewide refinery crude input with crude of the same quality as that refined in East Coast PADD 1 (2005–2008) could cut statewide refinery emissions to about 112 pounds/barrel—a reduction of about 20%, or ~8 million tonnes/year below observed 2009 emissions.

Comparison with the 10% cut in refinery emissions envisioned by 2020 via product fuels switching under California's Low Carbon Fuel Standard suggests that this possible range of emissions changes (+44% or –20%) could overwhelm other emissions control efforts.

In light of the findings reported here, the California refinery crude supply switch that is happening now presents a crucial challenge—and opportunity—for climate protection and environmental health.

[2] This prediction for heavy oil as defined by USGS does not represent worst-case refinery emissions; it is near the low end of the heavy oil/natural bitumen range predicted *(ref. 2; SI; Table S8; central prediction for heavy oil).* Nor does it include emissions from crude production: work by others *(12, 16, 38)* has estimated an *additional* emission increment from extraction of heavy and tar sands oils versus conventional crude that is roughly as great as this emissions increase from refining.

Recommendations

To ensure environmental health and climate stability it will be necessary to develop and enforce policies that prevent or limit emissions from refining lower quality grades of crude oil.

Existing state and federal policies have not identified crude quality-driven increases in refinery emissions. As a result they have not limited or otherwise prevented very large increases in the emission intensity of refining that exceed the emission targets of these current policies. Continuation of these policies without change will likely fail to achieve environmental health and climate goals.

Expand refinery crude feed quality reporting to include crude oil from U.S. sources.

Currently, every refinery in the U.S. reports the volume, density, and sulfur content of every crude oil shipment it processes, and that is public—but only for foreign crude. (www.eia.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html) The quality of crude refined from wells on U.S. soil is exempted. Since California's major fuels refineries use U.S. crude too, this hides facility crude quality from the public and from publicly verifiable environmental science. That limits this report's analysis of individual refineries, but very high crude quality-driven emissions found at two of the five facilities analyzed suggest that GHG copollutants disparately impact communities near refineries processing dirtier oil. The public has a right to know about how U.S. oil creates pollution of our communities and threatens our climate. State and federal officials should ensure that the U.S. crude refined is reported just like the foreign crude refined.

Compare refinery carbon emission performance against national or worldwide refinery performance.

The extreme-high average CO_2 emission intensity of California refineries revealed in this report was discovered only by comparing them with refineries in other parts of the U.S. This alone makes the case for rejecting the alternative of comparing refinery performance only within California. Doing that would compare "the worst with the worst," and thus risk erroneously establishing a statewide refinery emissions rate that is 33% dirtier than the average emissions rate achieved across a whole U.S. refining region as environmentally "acceptable" performance.

Moreover, this report demonstrates that comparing refinery performance across U.S. regions allows one to verify and know which causal factors do and do not drive changes in refinery emissions. That knowledge enables actions to prevent and reduce emissions. This is the *reason* one tracks emission performance.

The crude feed quality and products model evaluated here measures and predicts emissions per barrel crude refined based on the density and sulfur content of crude feeds, refinery capacity utilization, and the ratio of light liquids (gasoline, distillate, kerosene and naphtha) to other refinery products. It is based on data for U.S. Petroleum Administration Defense districts 1, 2, 3 and 5 over ten recent years. Energy intensity predicted by these parameters is compared with fuels data using CO_2 emission factors developed for international reporting of greenhouse gas emissions in the U.S. Data and methods are freely available at http://pubs.acs.org/doi/abs/10.1021/es1019965.

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Technical Appendix,
Oil Refinery CO_2 Performance Measurement
Revision 1, September 2011

Prepared for the

Union of Concerned Scientists

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September 2011

File No. COMMBETTERENVFY11103

Technical Appendix, Oil Refinery CO_2 Performance Measurement

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Technical Appendix, Oil Refinery CO_2 Performance Measurement

Purpose and scope

The purpose of this project is to develop and recommend a metric that can be used to measure petroleum refinery greenhouse gas (GHG) emissions intensity accurately and identify potential changes in emissions for controlling them reliably (a "benchmark"). Closely tied to this purpose, the project seeks to document the ability of alternative benchmark options to measure factors that drive refinery emissions, and thus be used to help identify opportunities for preventing, controlling, and reducing those emissions.

Four assumptions that were introduced at project conception served to focus, limit, and define its scope. First, the project was limited to technical assessment. Second, at least three types of refinery emission performance metrics would be assessed:

- A metric that would attempt to benchmark refinery emissions against refinery complexity—a term that refers to measurements based on the types and capacities of processes used by a refinery following initial atmospheric crude distillation.
- A metric that would attempt to benchmark refinery emissions against refinery products output, meaning the production or yield of some or all refined products.
- A metric that would benchmark refinery emissions against crude feed quality; specifically, the density and sulfur content of crude oil feedstock processed by refineries. These metrics are described in detail below.

The third initial assumption was that the applicability of the benchmark to refineries in California and other regions would be assessed. Fourth, available California-specific refinery data would be assessed.

Analysis focused on carbon dioxide (CO_2) emissions from fuels refineries. This reflected known differences between fuels refining and asphalt blowing, and the recognition that CO_2 predominates the total global warming potential of greenhouse gases emitted by oil refining. Taken together these two limitations in project focus exclude only 1–2% of 100-year horizon CO_2e mass emitted by oil refining in California *(1, 2)*.

Boundary conditions were set to include emissions at refineries and from purchased fuels consumed by refineries. The alternative of excluding purchased fuels consumed by refineries was rejected because ignoring relationships of refinery processing and feeds to those energy and emissions commitments—especially with respect to captive and third party hydrogen plants often co-located with refineries—would introduce potentially large and unnecessary errors. This boundary excludes emissions from the production and transport of refinery feedstock and from the transport and use of refinery products.

Approach

Assessment was based on data from observations of refineries in actual operation. This approach differs from those which use process design parameters to generate data inputs that are then analyzed in linear programming (LP) or analogous models constructed to represent refinery operations. See, for example Keesom et al. *(3);* Brederson et al. *(4).* Strengths of the "data-oriented" approach used here include avoidance of error associated with the need to make assumptions about processing parameters that vary within and sometimes beyond design parameters in actual refinery operation, and transparent separation of observations from expected causal relationships. Observed data and expected causal relationships may be intertwined by the assumptions embedded in inputs generated from process design data and embedded in algorithms of LP models. A weakness is its limitation to observed and recorded data, which limits its use in cases of not-yet-built breakthrough technology that do not apply here, and limited its use, for this project, to analysis of available publicly reported data.

A ten-year data set encompassing 97% of the U.S. refining industry that was gathered and validated for recently published work *(1)* was selected as the comparison data for this assessment (the "U.S. data"). Data from California refineries were gathered and assessed for their quality. The data were assessed based on petroleum refinery engineering and physical chemistry knowledge to identify causal bases for interactions of variables to be analyzed, and were compared with the U.S. data to check for consistency of response strength among variables, before quantitative analysis.

Quantitative analysis was designed first to assess the power of a metric option to predict refinery emissions intensity, based on independently observed emissions, and second; its reliability of prediction related to factors explaining emissions intensity based on comparison observations. These criteria flowed from the measurement accuracy, and identification of potential emission intensity change, purposes described above.

Partial least squares regression (PLS, XLSTAT 2009) was used where supported by available data. This analysis model was described previously *(1).* PLS allowed for the intended focus on the primary interest in prediction of y (e.g., emission intensity) and secondary interest in weights of x variables (e.g., factors driving emissions) while addressing the expectation that these factors may be correlated. Analysis by PLS also afforded comparability with recently published analysis of the U.S. data *(1).* Support for PLS by available data was defined for each analysis run as results suggesting that PLS residuals were distributed normally for each of four descriptive tests (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05). If this requirement was not met for PLS, analysis was by nonparametric regression (LOWESS, XLSTAT 2009) with the same criterion for acceptable distribution of residual error by all of those four tests.

California refinery data were analyzed in the prediction mode of the PLS or LOWESS models on the U.S. data. Data inputs were reported with results for each analysis.

Narrative description of the data

<u>Annual average data for refinery groups</u>. Weighted annual average refinery crude feed volume, density and sulfur content, process capacity, fuels, yield, capacity utilization, energy, and emissions data for California (2004–2009) and U.S. Petroleum Administration districts (PADDs) 1, 2, 3 and 5 are shown in Table 2-1. PADD 4 data were excluded based on observed anomalies that could not be resolved due in part to incomplete crude feed data reporting. These U.S. data were taken from recently published work that describes the U.S. data and PADD 4 anomaly in detail *(1)*.

The California Energy Commission (CEC) *(5)* reported annual average California crude feed volume data. California refinery crude feed quality data are discussed below. Refinery process capacities shown were volumes that could be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime, from *Oil & Gas Journal (6)*.

Fuels consumed by California refineries shown in Table 2-1 for 2006–2009 were provided by the CEC *(7),* and those shown for 2004–2005 were provided by Air Resources Board (ARB) staff *(8)*. Errors in the 2006–2007 fuels data were discovered, investigated, and corrected by CEC staff during the data gathering effort for this project *(7)*. Table 2-1 includes the fuels data corrected and revised by CEC staff with one exception: For the "other products" fuel category, which accounts generally for only ~1% of refinery energy and emissions, CEC staff suspected an as-yet unresolved error in the 2006–2009 data reported *(7)*. Those suspect data were replaced for these years (2006–2009) in Table 2-1 with the 1999–2005 average of "other" fuels reported for California.

Although impacts of all U.S. refinery hydrogen demand required estimation *(1),* for California refineries the CEC data included energy consumed by refinery-owned hydrogen production *(7)*. The method used for U.S. refinery hydrogen was applied only to California refinery hydrogen purchased from third-party plants, and broken out as hydrogen purchased by California refineries ("H_2 purch.") or "third-party H_2 prod." in Table 2-1. This application of 90% capacity utilization, energy and emission factors for modern-design natural gas fed steam reforming *(1)* was conservative for California refineries given the evidence that they are generally hydrogen-limited *(9)* and the known use of naphtha steam reforming by some of them *(6)*. Independent emissions reports by third-party plants *(2)* supplying hydrogen to California refineries showed good agreement within 2–3%. Calculations for this third-party refinery hydrogen supply data check are shown in Table 2-2. Note that although these emissions are clearly related to steam reforming's great hydrocarbon fuel and feedstock consumption and high operating temperatures (~1500 ºF) *(9)*, most of the CO_2 emitted by this process forms in its shift reaction rather than as a direct product of combustion.

Products yield was calculated as defined by the U.S. Energy Information Administration (EIA) from California refinery input and output data reported by the CEC *(10, 11)*. Reporting inconsistencies for kerosene subcategories in 2009 that were identified during project data gathering were confirmed and corrected by CEC staff *(11)*. The kerosene and kerosene jet fuel yields for 2009 in Table 2-1 reflect those corrections. Utilization of operable refinery capacity for California was calculated as defined by EIA from the feed volume *(5)* and atmospheric distillation capacity *(6)* data in Table 2-1. Annual average refinery capacity utilization 2004–2009 ranged 83–95%. Process-level capacity utilization was not otherwise reported, indicating a processing data limitation.

California refinery energy consumption and CO_2 emissions were calculated from fuels consumed and the same fuel-specific energy and emission factors used for the U.S. *(1)* except for the emission factor for electricity purchased from the grid. The U.S grid factor (187.78 kg/GJ) was replaced by the California factor (97.22 kg/GJ) to reflect the greater share of hydropower in the California grid purchases by these refiners. Emission factors applied to combustion of fuels, including both of these grid factors, were developed, documented and used by EIA for international reporting of U.S. emissions *(1, 12, 13)*.

Table 2-1 shows emissions by fuel energy (kg/GJ) and crude volume processed (kg/m^3). These emissions for California refineries (354–401 kg/m^3, 2004–2009), span previously reported S.F. Bay Area emissions (360 kg/m^3, 2008), which exceed reported average U.S. refinery emissions (277–315 kg/m^3, various years) for reasons that could be explained primarily by differences in crude feed quality *(1)*. These fuels-based emissions, however, may also exceed the average from California refineries' total from Mandatory GHG Reporting Rule (MRR) reports (351–354 kg/m^3 with purchased H_2, 2008–2009) *(2)*. It was not possible to account for that apparent discrepancy because data and calculation details for the MRR-reported emissions are kept secret from the public by ARB policy. The more transparently supported fuels consumption-based emissions estimates were used in quantitative analysis of average California refinery emissions for these reasons.

Average California refinery crude feed density and sulfur content was not previously reported *(1)*. EIA reported these data for U.S. PADDs and some other states but not for California *(14)*. California Petroleum Industry Information Act forms M13, M18 and A04 do not require these data to be reported. The ARB responded to a formal request by confirming that its staff could find no records related to these data *(15)*. These data were reported for the foreign crude streams processed at each facility monthly *(14)*. They were also reported for the Trans-Alaska pipeline stream from the Alaskan North Slope *(16)*, but not for the average California-produced crude stream refined.

Because California-produced crude was not refined in appreciable amounts outside California *(17–20)*, the quality of the California-produced stream refined statewide could be estimated based on that of total California production. The density and sulfur content of California crude feeds shown in Table 2-1 was calculated from these annual estimates for California-produced crude and the other crude streams refined in California by the standard weighted averaging method that is summarized in Table 2-3.

Public databases reported density and sulfur content data for most of the oil streams produced in California *(16, 21–24)*. Annual production volumes *(25)* were matched to the average of these reported density and sulfur data by field, and where data were reported, by area, formation, pool or zone. The matched data are shown in Table 2-4. Some 480–550 areas, pools, formations or zones produced crude among California oil fields annually 2004–2009; more than 99% of that total volume was matched to density measurements and 94–96% was matched to sulfur, 2004–2009. In light of the knowledge that the specific geologic conditions containing an oil deposit constrain its quality, this measured coverage and large number of component streams (Table 2-4) provide support for the California-produced crude quality estimates shown in Table 2-3. However, the quality of crude produced from the same formation, zone and even well can vary to some extent over time, and individual refineries run crude of non-average quality. Reporting domestic refinery inputs in the way foreign inputs are reported would provide substantially better quality data for future analysis, especially facility-level analysis.

<u>California facility-level data</u>. Process capacities were reported in barrels per calendar day for each major fuels refinery and some of the smaller plants targeting other products in California, by *Oil & Gas Journal (6)*. These data are presented in Table 2-5. Capacity data were found to be aggregated among facilities in three cases. Two of these paired facilities were located near each other in Wilmington and Carson. In those cases the aggregated data are reported in Table 2-5.

In the third case, facilities reporting aggregated capacities were too distant (~250 miles) for integration of process energy flows, such as shared hydrogen and steam. In addition, these facilities had reported capacities separately to EIA *(14)* and had reported emissions separately to ARB *(2)*. Capacities of these two facilities, the ConocoPhillips Rodeo and Santa Maria refineries, were disaggregated by process-level comparisons between the *Oil & Gas Journal (6)* and EIA-reported data *(14)* to obtain capacities for each refinery in barrels/calendar day. The EIA data were not substituted directly because EIA reported capacities for most processes in barrels per stream day, which in general would provide less accurate indications of actual operation. Historic effluent discharge permits files for the Rodeo refinery provided a check on, and compared to, the disaggregated results.

Facilities were ranked by crude capacity (atmospheric crude distillation capacity) in Table 2-5 to facilitate visual inspection of the data. The larger facilities from the top through most of the vertical span of the table are California's fuel refiners: smaller facilities at the bottom of the table largely target different products or intermediates. Hydrotreating of gas oil, residua and oils to be fed into catalytic cracking units is tabulated separately from product hydrotreating to reflect a distinction among refinery processes perhaps first articulated by *Speight (29)*. The first six processes shown in the table[1] are the primary processes acting on crude and its denser gas oil and residual oil components; product hydrotreating and the following half-dozen processes act on the unfinished products from those primary or "crude stream" processes *(29, 1)*. Primary processing capacity was concentrated among the large fuels refineries in California.

Emission intensities of individual California fuels refineries were estimated by adding excluded emissions associated with hydrogen to refinery emissions reported under California's Mandatory GHG Emissions Reporting Rule (MRR), and comparing mass emitted against the facility's atmospheric distillation capacity (Table 2-5). This was necessary because facility-level fuel consumption, crude feed volume, and products yield data were not reported, and MRR reporting excluded much of the emissions from making hydrogen used by refineries from refinery emission reports.

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[1] Atmospheric distillation, vacuum distillation, coking and thermal cracking, catalytic cracking, hydrocracking, and hydrotreating of gas oil, residua and catalytic cracking unit feeds.

Refiners did not report emissions from hydrogen production they relied upon through purchase agreements with nearby third-party producers under MRR; those emissions were reported separately by the third-party hydrogen plants *(2).* Refiners did, however, report the third party hydrogen capacity asset they had secured to *Oil & Gas Journal (6).* Those reported capacities compare reasonably well to emissions from the third-party plants reported in 2008 and 2009 under the MRR (Table 2-2). During this period the facilities reporting third-party hydrogen supply and their third-party suppliers were co-located: in the northeastern S.F. Bay Area; and in a stretch of the Los Angeles Area from El Segundo to Wilmington in *(2, 6).* Third-party hydrogen emissions were assigned to refiners in proportion to their reported reliance on that hydrogen in each region. The calculation is shown with estimated facility emission intensity results in Table 2-6.

Average California refinery capacity utilization rates and MRR-reported emissions approaching but less than 100% of reported capacity and fuels emissions implied both the potential for underestimation of facility-level emissions intensities for some refineries, and constraints on the magnitude of that error for the facility data set as a whole. Table 2-6 results were accepted, conditioned on this uncertainty, to account for facility-level variability that could otherwise be obscured by focus on statewide averages alone, and because better facility estimates were unavailable due to limitations in reported data.

Crude feed quality data reported at the facility level were sparse at best. Although EIA reported the density and sulfur content of all foreign-sourced crude refined by each facility *(14),* these data were not reported for domestically produced crude inputs to facilities. Foreign crude volumes refined *(14)* remained significantly smaller than atmospheric distillation capacities (Table 2-5) for the major California fuels refineries 2004–2009, indicating that these facilities processed Californian and/or Alaskan crude as a significant or substantial portion of their feeds. Nonreporting of crude feed quality was thus a major limitation in the data. This lack of domestic crude feed quality reporting at refineries contrasted with the public reporting of density and sulfur measurements for nearly all of the crude streams refined in California (tables 2-3, 2-4) *before* the oil passed through the refinery gate.

Site-specific supply logistics allowed crude streams of known quality to be traced to S.F. Bay Area refineries by volume. Bay Area refineries received crude from well reported foreign sources *(14),* adequately documented Alaska North Slope (ANS) crude blends *(16)* delivered by ship from the TAPs pipeline terminus, and via a pipeline carrying a blend of the crude oils produced in California's San Joaquin Valley *(1, 5, 19, 20, 26).* Recently published work apportioned those crude supply streams among facilities to derive crude feed density and sulfur estimates that supported an emission prediction which compared well to that independently reported for 2008 by Bay Area refineries *(1).* This project built on that previous work.

San Joaquin Valley (SJV) crude supply data gathered for 2008 (Table 2-4) matched density and sulfur content measurements to 99.9% and 98.8%, respectively, of the total crude volume produced by 489 production streams in the SJV. These data were used to update the weighted average density and sulfur content of the SJV pipeline stream. The same ANS data used for the California average, which was from in the TAPs pipeline terminus at Valdez *(16),* was applied to the Bay Area ANS stream as well. Weighted averages of the SJV, ANS and foreign streams were taken to estimate Bay Area refineries' crude feed quality. The calculations are shown in Table 2-7.

A crude feed mixing analysis was performed by the same method used to assess the adequacy of crude feed quality data in recently published work *(1)*. Gravity (density) and sulfur content are among the most widely used indicators for crude value, and are used to price crudes, largely because they are general predictors for other characteristics of oil that affect its processing for fuels production. Density and sulfur correlate roughly with distillation yield and with asphaltic, nitrogen, nickel and vanadium among well-mixed blends of crude oils from various locations and geologies *(1, 28, 29)*. California crude feeds 2004–2009 were found to be roughly as well mixed as those shown to be adequately mixed to support predictions of processing, energy, and emission effects among U.S. PADDs 1, 2, 3 and 5 *(1)* (Table 2-8). This supported the adequacy of the California crude feed density and sulfur data for purposes of the analysis targeted here.

Refinery capacity utilization, light liquids/other products ratios and fuel mix emission intensities were not available at the regional and facility levels because crude volume processed, products yield, and fuels consumption by refineries were not reported at the regional and facility levels, for California refineries. Previous work addressed this data limitation, as it applies to predictions based on available data, by assigning the most representative available average reported among U.S. PADDs, as in the Bay Area emissions prediction referenced above *(1)*. The California average data gathered by the project allowed this proxy to be refined to some extent by applying the 2008 California average data to the S.F. Bay Area region. Facility-level analysis for Bay Area refineries conservatively assumed the full variability observed among all regions and years.

<u>Data adequacy overview</u>. For California refineries as a group, the quality of data that could be found from verifiable public reports was adequate but poorly accessible. The errors found and addressed as disclosed above were judged to reflect the intensity of data validation effort rather than a departure from the typical—and perhaps inevitable—error rate for data sets of this kind. At the facility level, however, data quality was poor: Feed volume, fuels usage, products yield and emissions verification data as well as crude feed density and sulfur content for most refineries were not reported. The need for attention to refinery crude feed quality reporting and documentation beyond this project, perhaps obvious from the foregoing, appears urgent. This assessment applies to publicly reported data for the parameters identified above: confidential, proprietary, or otherwise secret data are not publicly verifiable and were not used.

Validation that the data adequately describe refinery emissions performance across regions accounted for the limited quantity of California data that could be gathered and the potential for nonlinear relationships among causal drivers of emissions. PADD 5 data were excluded for years when California data were included in the comparison mode of regression analyses because California is part of PADD 5. An attempt to balance observation counts among regions by subsampling the data led to a relatively small analysis sample (N = 24). Results from that too-small sample, reported for transparency only (Table 2-9), were discarded and were not used in the analysis. Instead, California (2004–2009) and PADD 5 (1999–2003) data were resampled to balance data counts among regions without excluding any PADDs 1–3 data (1999–2008) from the sample analyzed (N = 52). Analysis was by nonparametric regression to account for nonlinear relationships among causal factors. Refinery emission intensity, energy intensity, crude feed density and sulfur, fuel mix emission intensity, light liquids/other products ratio, primary processing capacity, and capacity utilization were analyzed in the comparison mode of the model. Residuals from these analyses appeared normal (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05). Results supported consistent relationships among causal factors across regions. Crude quality and products could explain 97% of variability in energy intensity and 96% of variability in emissions, and observed and predicted values differed by ≤ 4% for California refineries and ≤ 9% for all refining regions in all cases. Crude quality alone could explain 92% of variability in emissions, and observed and predicted values differed by ≤ 6% for California and ≤ 11% for all regions in all cases. Data inputs and results are shown in Table 2-10.

Emission measurement is central to every emissions performance benchmark assessed herein and therefore warrants explicit attention. Briefly: Applying emission factors developed from measurements taken elsewhere to a new, unmeasured source requires many assumptions. Direct sampling and analysis of samples taken at the points of emission—in cases where it was done well—has demonstrated that errors related to those assumptions render the "emission factor" approach inaccurate or unreliable for pollutants that vary dramatically with combustion conditions. Best practices for assessing such emissions apply emission factors to known activity rates, such as the types and amounts of fuels burned, only where direct sampling measurements are not available or suspect. Direct measurement of emissions is the best practice and should be required and reported.

The assumption of constant combustion conditions is prone to relatively smaller errors, however, when applied to combustion products that dominate the emission stream and vary proportionately little with typical combustion variability, such as CO_2. Importantly, CO_2 predominates among greenhouse gases in refinery emissions, accounting for more than 98% of emitted CO_2e in 100-year horizon assessments *(1, 2)*. Thus, the application of appropriate emission factors to accurate fuels data is relatively, and perhaps uniquely, accurate and reliable for the pollutant of main interest in the present analysis. This is fortunate, since comprehensive direct measurements of refinery emissions have not yet been required or reported.

Documentation of analysis methods

<u>Support for causal relationships of variables analyzed</u>. The physical chemistry of petroleum fuels refining presents an inescapable equation: Making light, hydrogen-rich fuels from crude that is more carbon-dense and hydrogen-poor requires more energy *(3, 4, 9, 28, 30–35)*. Carbon must be rejected, hydrogen must be added, or both, and burning fuel for that energy emits more CO_2 and other combustion products. Carbon rejection and aggressive hydrogen addition—thermal cracking, coking, catalytic cracking, hydrocracking, and hydrotreating of gas oil and residua—are the core of oil refining in the U.S. and California (tables 2-1, 2-5). As these processes, the vacuum distillation capacity that helps to feed gas oil to them, and the fossil energy-fed production of

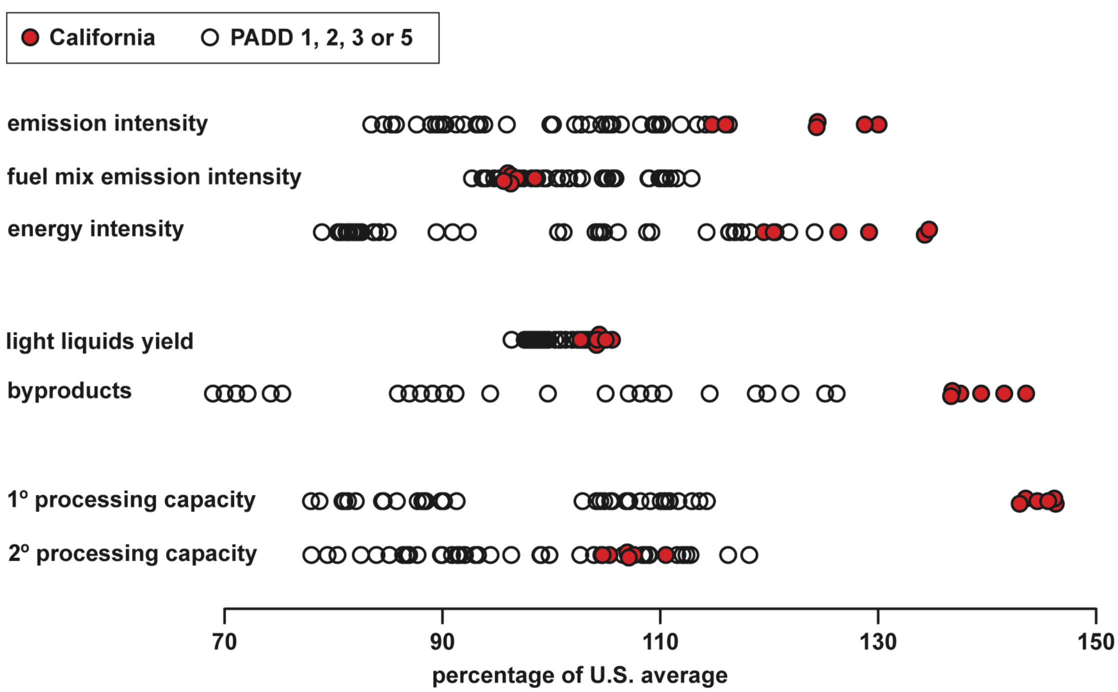
hydrogen feeding them, expand to a larger share of the lower-quality crude barrel, energy and emission intensities grow. Effects of these causal relationships have been observed and measured across the U.S. refining industry *(1)*.

Annual average statewide California refinery performance followed and extended the continuum of U.S. regional performance and showed consistent responses with the U.S. data for causally related factors, but represented the extreme of high emission intensity (Figure 1-1). California emissions and energy intensities were high while fuel mix emissions intensity was not, indicating that burning more fuel, rather than burning dirtier fuel, caused the high California emissions.

California refineries' capacity for "primary" processing acting on the crude stream and its denser components *(29),* and their by-production of coke and fuel gas created by that processing, were also high, while their light liquids (gasoline, distillate and jet fuel) yield and "secondary" products finishing capacity were within or near the national range.

These relationships among performance factors are consistent with those observed among U.S. refining regions, where lower quality crude feeds boosted emissions by increasing refinery energy intensity *(1)*.

Figure 1-1. Refinery performance data for California 2004–2009, and other U.S. regions 1999–2008

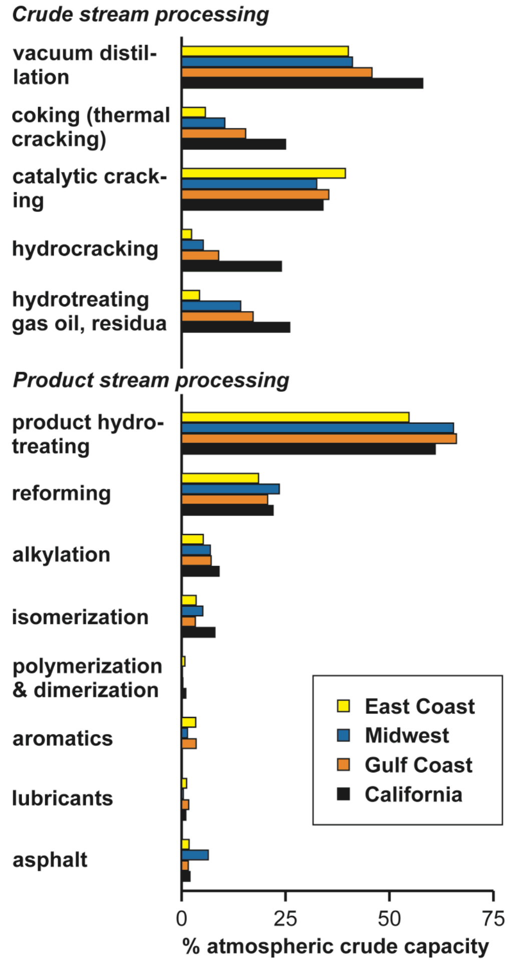


Annual observations. Data from Table 2-1.
Emission intensity: CO_2 emitted/barrel crude refined. **Fuel mix emission intensity:** CO_2 emitted/Btu fuel energy burned. **Energy intensity:** fuel energy burned /barrel crude refined. **Light liquids:** gasoline, distillate and jet kerosene fuel. **Byproducts:** petroleum coke and fuel gas.
Primary processing: processes acting on crude, gas oil and residua ("crude stream" processing).
Secondary processing: processes acting on product streams produced from crude by primary processing.

The extreme-high average refinery emissions intensity cannot be explained by treating product streams harder to make California-compliant gasoline and distillate diesel alone. California product hydrotreating and reforming capacities are similar to those elsewhere (Figure 1-2). Instead, greater crude stream processing capacity—driven by greater vacuum distillation, thermal coking hydrocracking, and hydro-treating of gas oil—distinguishes California from other U.S. refining regions, in terms process capacity.

Hydrocracking and hydrotreating of gas oil and residua uses much more H_2 per barrel processed than does product hydrotreating *(38)*. Combined capacity for hydrocracking and hydrotreating gas oil that is almost as large as product hydrotreating capacity (Figure 1-2) would thus use much more hydrogen than product hydrotreating in California (Fig. 1-3). Across U.S. PADDs refiners' hydrogen use increases with crude density *(1, 3),* and with hydrocracking rather than product hydrotreating *(1).* This is important because hydrogen is among the major sources of CO_2 emissions from oil refining *(36, 37, 4).*

Figure 1-2. Refinery process capacities at equivalent atmospheric crude distillation capacity, averages for U.S. PADDs 1–3 (2003–2008) and California (2004–2009)



Data from Table 2-1.

Figure 1-3. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007

MMscf/day
Based on 100% capacity

Figure adapted from CBE (2008) analysis citing references 6 and 38 herein.

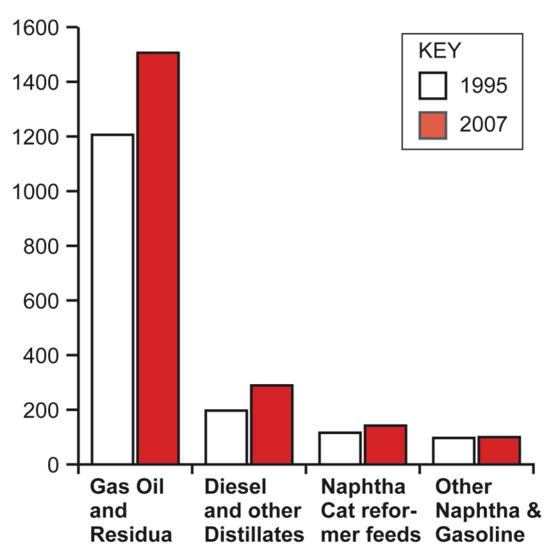
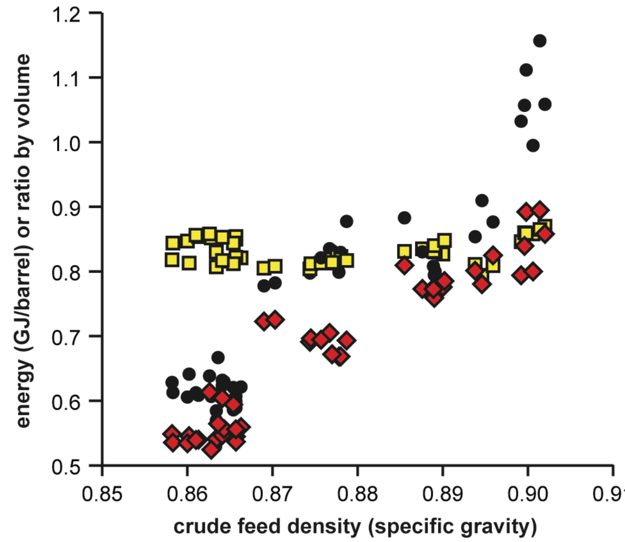


Figure 1-4. Refinery fuels production, conversion capacity and energy intensity with increasing crude density: annual observations from U.S. PADDs 1, 2, 3 and 5 (1999–2008) and California (2004–2009)



- refinery light liquids yield on crude, ratio by volume
- conversion capacity/light liquids produced, ratio by volume
- refinery energy consumed/vol. crude refined, GJ/barrel

Light liquids: gasoline, distillate, kerosene jet fuel and naphtha.

Data from Table 2-1

Total liquids production stays relatively flat across U.S. regions and California while refinery energy intensity rises steadily with crude feed density, and conversion capacity (thermal, catalytic and hydrocracking)—rising more steeply—becomes decoupled from energy intensity in California. (Figure 1-4). California conversion capacity exceeds California's total light liquid fuels production, implying more intensive serial processing or reprocessing of feeds in California conversion units. The pattern suggests California refineries may be squeezing out more gasoline, distillate, and jet fuel from lower quality crude in ways that may alter firing rates and emissions per unit processing capacity.

Poor refinery emissions performance on average in California 2004–2009, and the additional observation that this extreme-high refinery emissions intensity apparently went unnoticed until performance was compared with other U.S. regions, support benchmarking against national refinery performance.

Primary processing capacity and conversion capacity, which are types of refinery "complexity" metrics, are related to refinery crude feed variability, and expanded conversion capacity is probably helping to maintain California fuels yield despite declining crude feed quality. However, the decoupling of conversion capacity from energy intensity observed in California 2004–2008 indicates that refinery complexity did not measure emissions performance or that another factor confounded its measurement.

The types and amounts of products manufactured can be expected to affect emissions, but the variability observed among products was divergent: light liquids yield appeared to be maintained while byproducts yield increased with declining crude feed quality. This indicates that a products metric excluding some products could be unreliable, and further suggests the need to address crude quality as part of this metric.

Supporting discussion of causal relationships of crude quality is continued directly below.

<u>Crude feed quality metric</u>. Physical chemistry, petroleum engineering, and observational evidence consistently supports an energy intensity-crude feed quality causal pathway for observed differences in refinery emission intensity. This evidence supports the need for the emissions benchmark to address feedstock quality.

Recently published work *(1)* shows that crude feed density and sulfur predict energy and CO_2 emission intensities for U.S. and Bay Area refinery groups with diverse feeds, and provides a specific measurement and prediction model and robust data set spanning 97% of the U.S. refining industry and ten years. Assessment of the crude feed quality metric for California refineries adopted that metric and data set whole and without change and used them together with the newly-gathered California refinery data detailed and presented in this report.

U.S. data from PADDs 1, 2, 3 and 5, 1999–2008 *(1)* were used as the basis for prediction. California statewide average and Bay Area refineries data were analyzed in the prediction mode of PLS on the U.S. data. In the prediction mode of the model, emission intensity is predicted in two steps. First, refinery energy intensity (GJ/m^3 crude) is predicted by four explanatory variables:

- The density *(d)* of the crude feed in mass/volume crude;
- The sulfur content *(S)* of the crude feed in mass/volume crude;
- The refinery capacity utilization rate, as defined by U.S. EIA, in percent; and
- The light liquids/other products ratio, which is defined as the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products.

This gives the predicted refinery energy intensity in GJ/m^3. Second the prediction is multiplied with the measured fuel mix emission intensity (see Table 2-1 and/or reference 1 for fuel measurement detail), as CO_2 mass emitted/fuel energy (kg/GJ). Thus;

$$GJ/m^3 \cdot kg/GJ = kg/m^3$$

predicts refinery CO_2 emissions intensity in kg/m^3 crude refined. Refinery CO_2 emissions are essentially the same as refinery CO_2e emissions *(1, 2)* as discussed in the data section.

In practical terms, the energy and emissions intensity results make this an emissions performance *and* energy efficiency metric. That is important given that energy intensity is the dominant proximate cause of refinery emission intensity differences among U.S. *(1)* and California refineries on average. Finally, product slate effects on the relationships among crude feed quality and energy intensity are estimated directly through the inclusion of the products ratio as an explanatory variable. Thus, the metric also addresses products "output" yield.

Method development and validation is detailed in the original work *(1)*. All data used in this analysis of the metric are given in Table 2-1. Analysis input data are tabulated with the presentation of results below as well.

Equipment complexity metric. This option would attempt to use the size and variety of refinery process equipment capacities as a measurement or predictor for refinery emissions intensity. The concept for complexity most widely used by refiners is *equivalent capacity* (EQC): the ratio by volume of other process capacities to the capacity for atmospheric crude distillation. EQC is applied in different ways for different purposes. It is applied to the primary processing of crude, gas oil and residua as a way to measure a refinery's capacity for lower quality crude feeds *(1)*. In contrast, the Solomon indices are intended to be used, at least in part, for evaluating potential projects for their effects on margins and competitive position, according to Solomon Associates *(42)*.

Similarly, the Nelson Complexity Index applies weighting factors to the EQC of each process in a refinery as a way to calculate the value of a refinery or refinery capacity addition *(43)*. The Nelson Index predates the Solomon indices and remains in use as an industry standard for refinery complexity benchmarking by *Oil & Gas Journal (43)*.

An oil industry lobby group proposed a benchmark that would use an adjusted version of the Solomon Energy Intensity Index (EII) *(39)*. Air Resources Board (ARB) staff proposed that some type complexity metric should be considered, and stated that this metric might be based on the Solomon EII, although ARB acknowledged that Solomon EII data and methods are claimed proprietary and kept secret *(40, 41)*.

Because its data and methods are secret, the Solomon EII could not be assessed quantitatively. However, significant refinery capacity data are available for publicly verifiable analysis now (tables 2-1, 2-5). Initial assessment of these data, for example, identified the decoupling of conversion capacity from energy intensity observed in California (Figure 1-4), and raised questions about whether refinery complexity can measure emissions performance reliably. A range of publicly available complexity metrics was analyzed for this assessment.

Complexity was calculated for California and U.S. refineries as equivalent capacity applied to all refinery processing (refinery EQC), EQC applied to primary processing (primary processing EQC), and Nelson Complexity Index EQC (Nelson Index), using the California refinery capacity data in tables 2-1 and 2-5.

California refinery data were analyzed in the prediction mode of PLS or nonparametric models on U.S. data. Analysis was by nonparametric regression (LOWESS) for the Nelson Index and by PLS for the refinery EQC and primary processing EQC complexity metrics. Annual average California refinery data were analyzed for all three metrics. In addition, major refineries in the Los Angeles and Bay Area regions that collectively represent California fuels refining capacity were analyzed in the prediction mode of PLS on the U.S. data for the primary processing EQC. Finally, as an example of the potential for using process capacity in different ways to result in different capacity/energy intensity relationships, "adjusted" primary processing equivalent capacity, calculated by replacing observed gas oil/residua hydrotreating data for California with the lowest value observed (PADD 1, 2006–2008), was analyzed.

Product yield output metric: This option measures emissions against products yield (refinery products output). Air Resources Board (ARB) staff proposed emission-per-volume products as a benchmark option for consideration. This proposal would measure refinery emissions against the sum of "primary products" produced by California refineries: aviation gasoline, motor gasoline, distillate, kerosene jet fuel, renewable liquid fuels, and asphalt *(40, 41)*. Note that although this proposal includes "renewable liquid fuels," refineries report no production these fuels at this time (Table 2-1). ARB's proposal measures the sum of these products against emissions directly, without necessarily targeting energy efficiency, as is attempted by at least some of the concepts for complexity metrics.

The foregoing analysis (see discussion of figures 1-1, 1-4; crude feed quality metric) suggest that a products-based metric may be sensitive to the choice of which products to include or exclude, and that products and crude feed quality can be integrated into the refinery performance metric. Additionally, this metric may differ from the others assessed here and may warrant additional assessment discussed below.

Observed emissions were analyzed with the ARB primary products sum by nonparametric regression (LOWESS) and with the primary products "mix" by PLS. The "mix" analysis entered data for each fuel as PLS inputs instead of summing them to one input, which may provide additional information—and it excluded asphalt based on its difference from the light liquid fuels. Average California refinery data were analyzed in the prediction mode of the models run on the U.S. data. Facility-level analysis of this metric was not possible because facility-level yield data were not reported publicly. Estimated CO_2 emissions to produce gasoline, diesel, and kerosene (46.0, 50.8, and 30.5 kg/b respectively) from NETL *(32)* were applied to observed gasoline, distillate, and kerosene yields *(Table 2-1)* to derive "fuels emit" estimates for comparison with results.

Major plant capacity addition and thus refinery complexity is largely constrained by capital and permit requirements; and crude feed quality is constrained within fairly narrow limits by refinery configuration; the constraints supported focus on confirmed pathways of causality to support the variables analyzed. Relatively less "hard" evidence for causality was found for the variability, or stability, of product slates. This suggests products may change. That implies the need to assess the stability of this metric as a measurement that can be predicted by or related to other factors.

In part because of this consideration, and also because products were already integrated with crude quality as an explanatory *(x)* variable in the crude feed quality metric, this products metric was analyzed with crude quality as the dependent *(y)* variable in two forms. Emissions/volume total products, and emissions/volume light liquids (aviation gasoline, motor gasoline, jet kerosene, distillate, naphtha) were calculated for the California and PADDs averages each year. Each emission/volume product measurement was analyzed against the crude feed metric explanatory variables and California *x* data were analyzed in the prediction mode of the model on the U.S. data. Nonparametric regression was used for the emission/total products analysis; PLS was used for the emission/light liquids analysis.

Results

<u>Crude feed quality metric results</u>. Figure 1-5 shows results for energy intensity predicted by oil quality from this analysis. The *R*-squared value (0.90) and diagonal lines bounding the 95% confidence of prediction for observations indicate the power of prediction by this metric. Those results are derived from the U.S. refinery data, and were reported previously *(1)*.

Orange diamonds showing observations and predictions for California refineries annually 2004–2009 provide new information about the reliability of prediction by this metric. The energy intensity *(EI)* of California refineries falls within the prediction based on oil quality in 4 of 6 cases and falls within 2% of the confidence of prediction in all cases.

Table 1-1 shows data inputs, calculations, and results for CO_2 emissions as well as *EI* predicted by this metric. Predicted emissions are the product of *EI* predicted by crude feed quality in GJ/m^3 crude refined, and the emission intensity of the refinery fuel mix in kilograms CO_2 emitted per Gigajoule fuel energy ($GJ/m^3 \bullet kg/GJ = kg/m^3$ crude refined). Results for emissions are similar to those for *EI* because the fuel mix did not change much in these years. Predictions for multi-plant emissions include the six statewide observations from 2004–2009 and S.F. Bay Area refinery emissions in 2008. The statewide/regional emissions fall within the confidence of prediction in 5 of 7 cases and fall within 2% of its confidence interval in all cases.

Figure 1-5 Refinery energy intensity *(EI)* predicted by crude feed density and sulfur

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.90

Diagonal lines bound the 95% confidence of prediction for observations

Figure adapted from Figure 1 in *Env. Sci. Technol.* 44(24) 9584–9589; DOI 10.1021/es1019965; American Chemical Society

Data from Table 1-1

◆ **California annual average 2004–2009**

● **PADD 1, 2, 3 or 5 1999–2008**

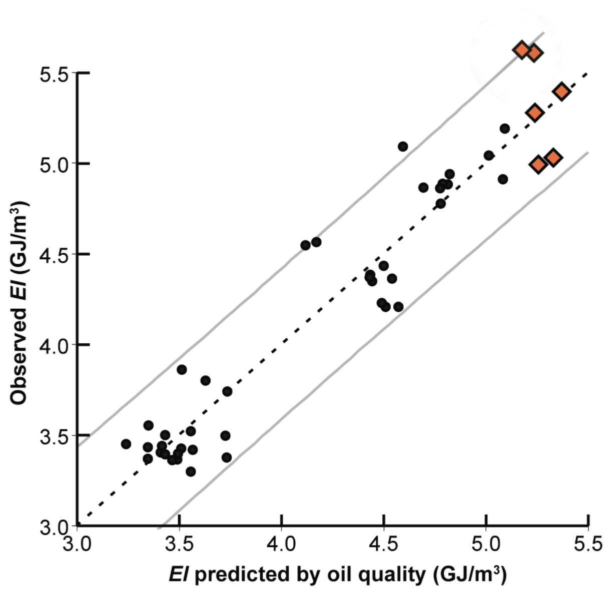


Table 1-1. Emissions predicted by crude feed quality

PADD	Year	*EI* (GJ/m^3)	density (kg/m^3)	sulfur (kg/m^3)	Cap. ut. (%)	Prod. ratio	*EI* pred. 95% confidence Lower	Central	Upper	Fuel mix (kg/GJ)	Emit pred. 95% confidence Lower	Central	Upper	Obs. CO_2 (kg/m^3)
1	1999	3.451	858.20	8.24	90.9	3.668	2.877	3.241	3.604	81.53	235	264	294	281
1	2000	3.430	860.18	8.00	91.7	3.489	2.987	3.349	3.711	80.34	240	269	298	276
1	2001	3.518	866.34	7.71	87.2	3.479	3.198	3.559	3.919	81.85	262	291	321	288
1	2002	3.426	865.71	7.45	88.9	3.605	3.152	3.511	3.870	81.08	256	285	314	278
1	2003	3.364	863.44	7.43	92.7	3.321	3.133	3.493	3.853	81.51	255	285	314	274
1	2004	3.416	865.44	7.79	90.4	3.397	3.209	3.568	3.927	81.46	261	291	320	278
1	2005	3.404	863.38	7.17	93.1	3.756	3.048	3.410	3.772	81.23	248	277	306	277
1	2006	3.440	864.12	7.17	86.7	3.522	3.054	3.417	3.780	80.40	246	275	304	277
1	2007	3.499	864.33	7.26	85.6	3.443	3.067	3.433	3.800	82.28	252	282	313	288
1	2008	3.551	863.65	7.08	80.8	3.400	2.972	3.352	3.733	83.26	247	279	311	296
2	1999	3.368	858.25	10.64	93.3	4.077	2.984	3.347	3.711	78.11	233	261	290	263
2	2000	3.361	860.03	11.35	94.2	4.132	3.104	3.468	3.832	77.56	241	269	297	261
2	2001	3.396	861.33	11.37	93.9	4.313	3.126	3.495	3.863	77.46	242	271	299	263
2	2002	3.393	861.02	11.28	90.0	4.345	3.068	3.432	3.796	77.90	239	267	296	264
2	2003	3.298	862.80	11.65	91.6	4.281	3.195	3.558	3.922	78.00	249	278	306	257
2	2004	3.376	865.65	11.86	93.6	4.167	3.369	3.733	4.098	77.25	260	288	317	261
2	2005	3.496	865.65	11.95	92.9	4.207	3.362	3.725	4.089	77.27	260	288	316	270
2	2006	3.738	865.44	11.60	92.4	3.907	3.380	3.738	4.095	75.84	256	283	311	284
2	2007	3.800	864.07	11.84	90.1	4.161	3.270	3.629	3.989	75.55	247	274	301	287
2	2008	3.858	862.59	11.73	88.4	4.333	3.154	3.515	3.875	74.97	236	263	291	289
3	1999	4.546	869.00	12.86	94.7	3.120	3.759	4.117	4.476	71.61	269	295	321	326
3	2000	4.563	870.29	12.97	93.9	3.120	3.813	4.172	4.531	71.87	274	300	326	328
3	2001	4.348	874.43	14.34	94.8	3.128	4.086	4.444	4.803	72.43	296	322	348	315
3	2002	4.434	876.70	14.47	91.5	3.251	4.140	4.499	4.859	72.71	301	327	353	322
3	2003	4.381	874.48	14.43	93.6	3.160	4.076	4.435	4.794	72.81	297	323	349	319
3	2004	4.204	877.79	14.40	94.1	3.228	4.213	4.572	4.930	73.43	309	336	362	309
3	2005	4.205	878.01	14.40	88.3	3.316	4.149	4.511	4.873	73.24	304	330	357	308
3	2006	4.367	875.67	14.36	88.7	3.176	4.067	4.433	4.798	74.15	302	329	356	324
3	2007	4.226	876.98	14.47	88.7	3.205	4.127	4.491	4.856	74.93	309	337	364	317
3	2008	4.361	878.66	14.94	83.6	3.229	4.165	4.540	4.915	74.48	310	338	366	325
5	1999	4.908	894.61	11.09	87.1	2.952	4.713	5.082	5.451	70.27	331	357	383	345
5	2000	5.189	895.85	10.84	87.5	3.160	4.725	5.092	5.460	69.09	326	352	377	358
5	2001	5.039	893.76	10.99	89.1	3.231	4.648	5.014	5.380	69.38	322	348	373	350
5	2002	4.881	889.99	10.86	90.0	3.460	4.450	4.814	5.178	69.15	308	333	358	338
5	2003	4.885	889.10	10.94	91.3	3.487	4.422	4.788	5.153	69.40	307	332	358	339
5	2004	4.861	888.87	11.20	90.4	3.551	4.410	4.775	5.140	69.89	308	334	359	340
5	2005	4.774	888.99	11.38	91.7	3.700	4.409	4.780	5.151	69.88	308	334	360	334
5	2006	4.862	887.65	10.92	90.5	3.615	4.331	4.695	5.060	69.32	300	325	351	337
5	2007	5.091	885.54	11.07	87.6	3.551	4.235	4.594	4.953	69.12	293	318	342	352
5	2008	4.939	890.16	12.11	88.1	3.803	4.456	4.824	5.191	68.39	305	330	355	338
Predictions for California refineries														
California average, 2004			899.23	11.46	93.0	3.633	4.881	5.256	5.632	70.82	346	372	399	354
California average, 2005			900.56	11.82	95.0	3.801	4.937	5.329	5.721	71.06	351	379	407	358
California average, 2006			899.56	11.73	91.5	3.845	4.861	5.239	5.616	72.65	353	381	408	384
California average, 2007			899.84	11.89	88.3	3.814	4.866	5.234	5.603	71.43	348	374	400	401
California average, 2008			902.00	12.85	91.0	4.087	4.980	5.370	5.759	71.02	354	381	409	383
California average, 2009			901.38	11.70	82.9	4.045	4.837	5.200	5.564	70.54	341	367	392	397
Bay Area '08 avg. assm.			895.72	10.95	91.0	4.087	4.602	4.980	5.357	71.02	327	354	380	376
Martinez '08 avg. assm.			932.08	9.86	91.0	4.087	6.076	6.504	6.931	71.02	432	462	492	497
Martinez '08 high case			932.08	9.86	95.0	3.160	6.276	6.690	7.105	83.26	523	557	592	497
Martinez '08 low case			932.08	9.86	80.8	4.333	5.974	6.365	6.756	68.39	409	435	462	497
Rodeo '08 avg. assm.			918.45	8.22	91.0	4.087	5.410	5.808	6.207	71.02	384	412	441	428
Rodeo '08 high case			918.45	8.22	95.0	3.160	5.609	5.995	6.381	83.26	467	499	531	428
Rodeo '08 low case			918.45	8.22	80.8	4.333	5.300	5.670	6.039	68.39	362	388	413	428
Benicia '08 avg. assm.			903.15	10.39	91.0	4.087	4.886	5.271	5.655	71.02	347	374	402	345
Benicia '08 high case			903.15	10.39	95.0	3.160	5.084	5.457	5.831	83.26	423	454	486	345
Benicia '08 low case			903.15	10.39	80.8	4.333	4.771	5.132	5.493	68.39	326	351	376	345
Richmond '08 avg. assm.			858.28	13.61	91.0	4.087	3.143	3.504	3.866	71.02	223	249	275	340
Richmond '08 high case			858.28	13.61	95.0	3.160	3.335	3.691	4.046	83.26	278	307	337	340
Richmond '08 low case			858.28	13.61	80.8	4.333	3.004	3.365	3.727	68.39	205	230	255	340
Avon '08 avg. assm.			899.24	9.80	91.0	4.087	4.685	5.064	5.443	71.02	333	360	387	313
Avon '08 high case			899.24	9.80	95.0	3.160	4.883	5.251	5.619	83.26	407	437	468	313
Avon '08 low case			899.24	9.80	80.8	4.333	4.567	4.925	5.284	68.39	312	337	361	313

Key to S.F. Bay Area prediction cases. Case inputs:
Average conditions assumption: avg 2008 California Cap. utiliztion, products ratio and fuel mix
Low case assumptions: D-1 2008 Cap Ut; D-2 2008 Pratio; D-5 2008 fuels mix
High case assumptions: CA-2005 Cap Ut; D-3 2003 Pratio; D-1 2008 fuels mix

Data from Table 2-1.

Individual refinery predictions in Table 1-1 compare to emissions reported for 2008 under California's Mandatory Greenhouse Gases Reporting Rule (see Table 2-6). Refinery-level capacity utilization, products ratio, and fuel mix data were not reported. Average 2008 California values as well as the lowest and highest values observed for California or any PADD were used for these inputs to create low, average, and high predictions. The low–high range of these predictions shown in Table 1-1 thus represents uncertainty in prediction caused solely by the unreported data. Accounting for that uncertainty, emissions reported by individual Bay Area refiners fall within the prediction in 4 of 5 cases. Emissions reported by the Chevron Richmond refinery in 2008 exceeded the upper bound of the high prediction by about 1% and exceeded the average prediction by 24%. This was expected, because inefficiency was reported by this refinery.[2]

Together with the results from previous analysis of the U.S. refinery data *(1),* and the causal relationships analysis above, these results provide evidence that crude quality is a relatively accurate and reliable predictor of California refinery emissions.

For the statewide refinery comparisons over the six annual observations, the central prediction for average California refinery emissions by this crude quality metric is within 1% of observed emissions.

[2] Its hydrogen plant, reformers and steam boilers were reported to be outdated and inefficient. *Chevron Renewal Project Application;* ChevronTexaco 17 June 2005 submission to Air Quality Mgmt. District.

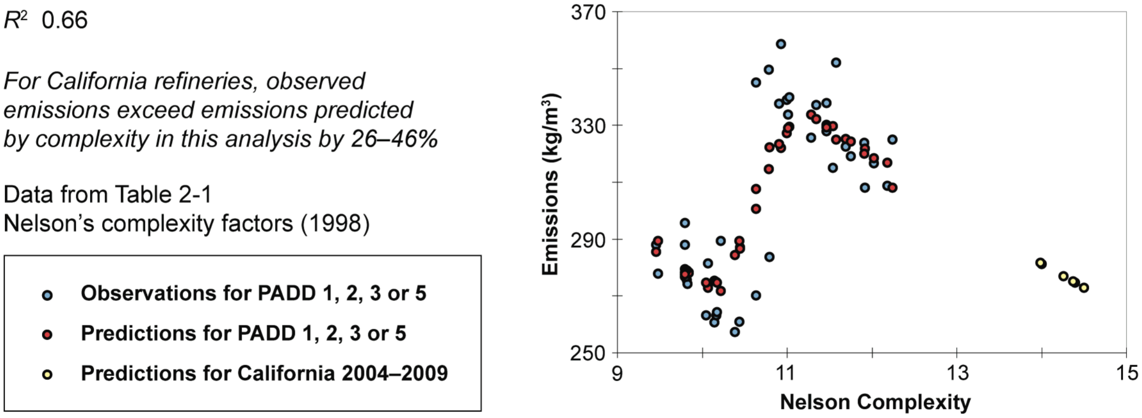
Figure 1-6. Emission intensity predicted by Nelson Complexity

Prediction for California refineries on 1999–2008 data from U.S. refineries by nonparametric regression

R^2 0.66

For California refineries, observed emissions exceed emissions predicted by complexity in this analysis by 26–46%

Data from Table 2-1
Nelson's complexity factors (1998)



Equipment complexity metric results. Figure 1-6 shows results for refinery emissions predicted by Nelson Complexity. The relatively low *R*-squared value (0.66) indicates relatively poor power of prediction for emissions. The undulating prediction curve (red and yellow circles in the chart), which trends downward at high complexity and predicts average emissions lower than those from most other refineries in California, indicates prediction error. Observed average California refinery emissions exceed those predicted by Nelson complexity substantially in all years (2004–2009), exceeding the complexity predictions by 26–46%.

In this analysis (Figure 1-6), complexity includes secondary processing that acts on product streams along with primary processing that acts on crude, gas oil and residua, because the Nelson Index values both classes of processing. However, the increasing energy intensity that drives refinery emissions is not significantly related to increasing capacity for major products processes and has mixed relationships to other products processes *(1),* and the conversion capacity excess observed (Figure 1-4) did not reflect observed California energy intensity. The poor power and reliability of Nelson Complexity for predicting emissions shown in Figure 1-6 is thus consistent with the decoupling of conversion capacity and energy intensity observed in the California data. However, it may also reflect a bias due to the *Nelson's* weighting factors being developed to measure the value of process capacity instead of measuring refinery emissions.

Energy intensities predicted by refinery equivalent capacity, and by primary processing equivalent capacity, are shown in figures 1-7 and 1-8, respectively. For complexity as refinery EQC, the very low *R*-squared value (0.35) and very wide confidence interval indicates very poor power of prediction. Observed average California refinery *EI* is consistently lower than predicted by refinery EQC. These emissions fall within the wide confidence of prediction by refinery EQC, but that only reflects its poor power. Average California refinery emissions intensity could increase by 21–30% and still be within the confidence of prediction by this metric (see Table 1-2).

For complexity as primary processing EQC, the relatively good power of *EI* prediction (*R*-squared 0.92; Figure 1-8) was expected, because increasing primary processing is strongly associated with worsening crude feed quality—the major driver of *EI*.

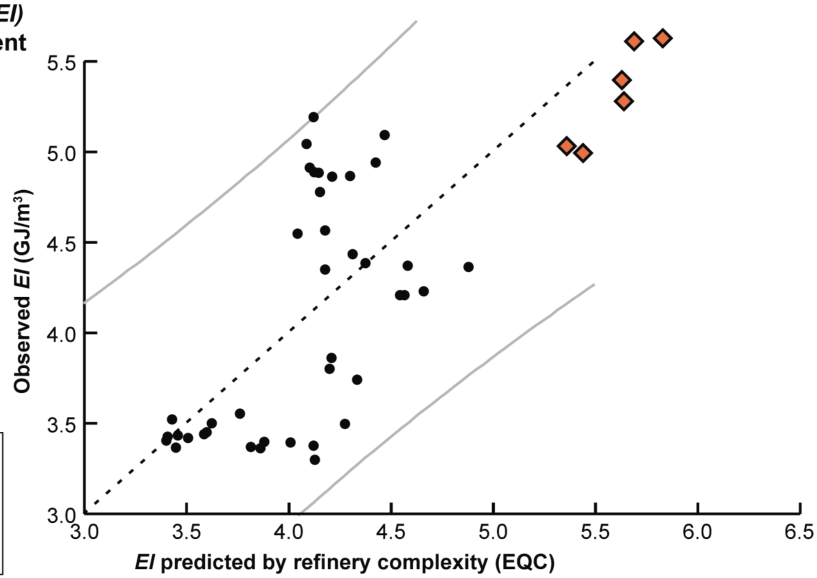
Figure 1-7. Energy intensity *(EI)* predicted by refinery equivalent capacity (EQC)

Prediction for Calif. on 1999–2008 data from U.S.

R^2 0.35

Diagonal lines bound 95% confidence of prediction for observations

Data from tables 1-2 and 2-1



California annual average 2004–2009

PADD 1, 2, 3 or 5 1999–2008

However, Figure 1-8 reveals a large shift to the right in the *EI* predicted for California observations. Average observed California emissions are exceeded by the lower bound of prediction by 9–15% in 6 of 6 years, and are 14% below the central prediction as a six-year average (Table 1-3). This demonstrates the reliability problem with complexity metrics that was suggested by the decoupling of conversion capacity from energy intensity observed in California. Complexity is not measuring energy intensity or emissions. It is erroneously equating capacity to energy intensity. In California, where conversion, hydrocracking, and gas oil hydrotreating capacities are high, predictions of energy and emission intensities based on complexity are biased high.

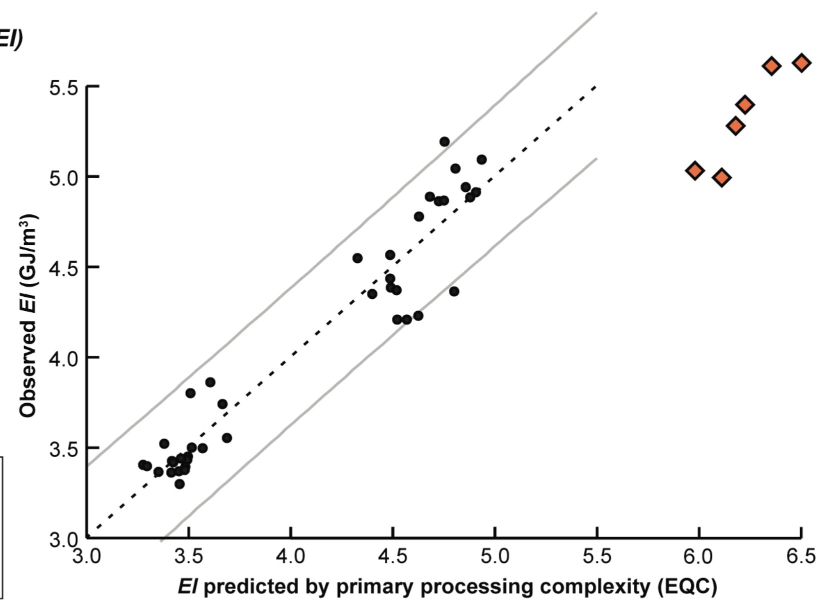
Figure 1-8. Energy intensity *(EI)* predicted by primary processing equivalent capacity

Prediction for Calif. on 1999–2008 data from U.S.

R^2 0.92

Diagonal lines bound 95% confidence of prediction for observations

Data from tables 1-3 & 2-1



California annual average 2004–2009

PADD 1, 2, 3 or 5 1999–2008

Table 1-2. Emissions predicted by refinery equivalent capacity (EQC)

		EI	Refinery	Cap.	*EI* pred. 95% confidence			Fuel mix	Emit pred. 95% confidence			Obs. CO_2
PADD	Year	(GJ/m^3)	EQC	ut. (%)	Lower	Central	Upper	(kg/GJ)	Lower	Central	Upper	(kg/m^3)
1	1999	3.451	1.861	90.9	2.69	3.60	4.51	81.53	219	294	368	281
1	2000	3.430	1.811	91.7	2.54	3.46	4.38	80.34	204	278	352	276
1	2001	3.518	1.744	87.2	2.51	3.43	4.36	81.85	205	281	357	288
1	2002	3.426	1.755	88.9	2.48	3.41	4.34	81.08	201	276	352	278
1	2003	3.364	1.819	92.7	2.53	3.45	4.38	81.51	206	281	357	274
1	2004	3.416	1.817	90.4	2.59	3.51	4.43	81.46	211	286	361	278
1	2005	3.404	1.804	93.1	2.47	3.40	4.33	81.23	201	276	352	277
1	2006	3.440	1.804	86.7	2.68	3.59	4.50	80.40	215	289	362	277
1	2007	3.499	1.807	85.6	2.72	3.63	4.54	82.28	223	298	373	288
1	2008	3.551	1.807	80.8	2.86	3.77	4.67	83.26	238	313	389	296
2	1999	3.368	1.983	93.3	2.92	3.82	4.72	78.11	228	298	369	263
2	2000	3.361	2.014	94.2	2.97	3.87	4.76	77.56	230	300	370	261
2	2001	3.396	2.017	93.9	2.98	3.88	4.78	77.46	231	301	370	263
2	2002	3.393	2.025	90.0	3.12	4.01	4.91	77.90	243	313	382	264
2	2003	3.298	2.095	91.6	3.23	4.13	5.03	78.00	252	322	392	257
2	2004	3.376	2.117	93.6	3.23	4.13	5.02	77.25	249	319	388	261
2	2005	3.496	2.174	92.9	3.38	4.28	5.18	77.27	261	331	400	270
2	2006	3.738	2.192	92.4	3.44	4.34	5.24	75.84	261	329	397	284
2	2007	3.800	2.106	90.1	3.30	4.20	5.10	75.55	250	317	385	287
2	2008	3.858	2.090	88.4	3.32	4.21	5.11	74.97	249	316	383	289
3	1999	4.546	2.096	94.7	3.15	4.04	4.94	71.61	225	290	354	326
3	2000	4.563	2.144	93.9	3.28	4.18	5.08	71.87	236	300	365	328
3	2001	4.348	2.156	94.8	3.29	4.18	5.08	72.43	238	303	368	315
3	2002	4.434	2.172	91.5	3.41	4.32	5.22	72.71	248	314	379	322
3	2003	4.381	2.224	93.6	3.47	4.38	5.28	72.81	253	319	385	319
3	2004	4.204	2.302	94.1	3.63	4.55	5.46	73.43	267	334	401	309
3	2005	4.205	2.241	88.3	3.66	4.57	5.49	73.24	268	335	402	308
3	2006	4.367	2.251	88.7	3.67	4.58	5.50	74.15	272	340	408	324
3	2007	4.226	2.285	88.7	3.74	4.66	5.59	74.93	280	349	419	317
3	2008	4.361	2.316	83.6	3.94	4.88	5.83	74.48	293	364	434	325
5	1999	4.908	2.029	87.1	3.21	4.11	5.00	70.27	226	289	351	345
5	2000	5.189	2.042	87.5	3.23	4.13	5.02	69.09	223	285	347	358
5	2001	5.039	2.047	89.1	3.19	4.09	4.99	69.38	222	284	346	350
5	2002	4.881	2.083	90.0	3.25	4.15	5.05	69.15	225	287	349	338
5	2003	4.885	2.089	91.3	3.23	4.13	5.02	69.40	224	286	349	339
5	2004	4.861	2.116	90.4	3.32	4.22	5.11	69.89	232	295	357	340
5	2005	4.774	2.106	91.7	3.26	4.16	5.05	69.88	228	290	353	334
5	2006	4.862	2.154	90.5	3.40	4.30	5.20	69.32	236	298	361	337
5	2007	5.091	2.190	87.6	3.56	4.47	5.38	69.12	246	309	372	352
5	2008	4.939	2.177	88.1	3.52	4.43	5.33	68.39	241	303	365	338
Predictions for California refineries												
California average, 2004			2.670	93.0	4.40	5.44	6.49	70.82	312	386	460	354
California average, 2005			2.657	95.0	4.32	5.36	6.40	71.06	307	381	454	358
California average, 2006			2.732	91.5	4.56	5.64	6.71	72.65	331	409	488	384
California average, 2007			2.717	88.3	4.62	5.69	6.77	71.43	330	407	483	401
California average, 2008			2.722	91.0	4.55	5.63	6.70	71.02	323	400	476	383
California average, 2009			2.711	82.9	4.76	5.83	6.91	70.54	336	412	487	397
BP Carson 2008			2.547	91.0	4.22	5.21	6.21	71.02	300	370	441	308
BP Carson 2009			2.544	82.9	4.44	5.44	6.44	70.54	313	384	454	302
Chevron El Segundo 2008			2.336	91.0	3.79	4.72	5.65	71.02	269	335	401	307
Chevron El Segundo 2009			2.333	82.9	4.01	4.94	5.88	70.54	283	349	415	273
Chevron Richmond 2008			2.843	91.0	4.78	5.91	7.05	71.02	339	420	500	340
Chevron Richmond 2009			2.830	82.9	4.98	6.11	7.25	70.54	351	431	512	321
CP Carson & Wilm. 2008			2.888	91.0	4.86	6.02	7.17	71.02	345	427	510	363
CP Carson & Wilm. 2009			2.888	82.9	5.08	6.25	7.42	70.54	358	441	523	320
ConocoPhillips Rodeo 2008			3.096	91.0	5.23	6.51	7.79	71.02	371	462	553	428
ConocoPhillips Rodeo 2009			3.346	82.9	5.87	7.33	8.79	70.54	414	517	620	425
ExxonMobil Torrance 2008			3.033	91.0	5.12	6.36	7.60	71.02	363	452	540	329
ExxonMobil Torrance 2009			2.943	82.9	5.18	6.38	7.58	70.54	365	450	535	311
Shell Martinez 2008			2.744	91.0	4.60	5.68	6.76	71.02	326	403	480	497
Shell Martinez 2009			3.001	82.9	5.28	6.52	7.76	70.54	373	460	547	514
Tesoro Avon 2008			3.186	91.0	5.38	6.72	8.06	71.02	382	477	572	313
Tesoro Avon 2009			3.186	82.9	5.60	6.95	8.31	70.54	395	491	586	276
Tesoro Wilmi./Carson 2008			3.238	91.0	5.47	6.84	8.21	71.02	388	486	583	376
Tesoro Wilmi./Carson 2008			3.238	82.9	5.69	7.07	8.46	70.54	401	499	597	341
Ultramar-Valero Wilm. 2008			3.871	91.0	6.50	8.33	10.17	71.02	462	592	722	287
Ultramar-Valero Wilm. 2008			3.871	82.9	6.72	8.57	10.42	70.54	474	604	735	293
Valero Benicia 2008			3.000	91.0	5.06	6.28	7.50	71.02	359	446	533	345
Valero Benicia 2009			3.000	82.9	5.28	6.52	7.75	70.54	372	460	547	357

Data from Table 2-1.

Table 1-3. Emissions predicted by primary processing EQC

		EI	Equivalent process capacities			Cap.	Prod.	EI_{pred} 95% confidence			Fuel mix	$Emit_{pred}$ 95% confidence			Obs. CO_2
PADD	Year	(GJ/m^3)	Vac. Dist.	Conv.	1°Hydrtg	ut. (%)	ratio	Lower	Central	Upper	(kg/GJ)	Lower	Central	Upper	(kg/m^3)
1	1999	3.451	0.402	0.516	0.054	90.9	3.668	3.171	3.498	3.826	81.53	259	285	312	281
1	2000	3.430	0.395	0.525	0.054	91.7	3.489	3.168	3.495	3.823	80.34	254	281	307	276
1	2001	3.518	0.387	0.481	0.029	87.2	3.479	3.049	3.382	3.716	81.85	250	277	304	288
1	2002	3.426	0.386	0.474	0.084	88.9	3.605	3.090	3.419	3.747	81.08	251	277	304	278
1	2003	3.364	0.398	0.474	0.059	92.7	3.321	3.022	3.355	3.688	81.51	246	274	301	274
1	2004	3.416	0.399	0.475	0.059	90.4	3.397	3.097	3.425	3.754	81.46	252	279	306	278
1	2005	3.404	0.402	0.476	0.058	93.1	3.756	2.947	3.279	3.611	81.23	239	266	293	277
1	2006	3.440	0.402	0.476	0.028	86.7	3.522	3.130	3.464	3.799	80.40	252	279	305	277
1	2007	3.499	0.402	0.476	0.028	85.6	3.443	3.181	3.518	3.856	82.28	262	289	317	288
1	2008	3.551	0.402	0.476	0.028	80.8	3.400	3.329	3.690	4.051	83.26	277	307	337	296
2	1999	3.368	0.408	0.486	0.125	93.3	4.077	3.124	3.454	3.784	78.11	244	270	296	263
2	2000	3.361	0.415	0.488	0.107	94.2	4.132	3.085	3.416	3.747	77.56	239	265	291	261
2	2001	3.396	0.407	0.485	0.096	93.9	4.313	2.967	3.298	3.629	77.46	230	255	281	263
2	2002	3.393	0.405	0.481	0.129	90.0	4.345	3.156	3.485	3.814	77.90	246	271	297	264
2	2003	3.298	0.408	0.477	0.132	91.6	4.281	3.130	3.458	3.786	78.00	244	270	295	257
2	2004	3.376	0.413	0.473	0.148	93.6	4.167	3.152	3.482	3.813	77.25	243	269	295	261
2	2005	3.496	0.420	0.484	0.148	92.9	4.207	3.242	3.570	3.898	77.27	251	276	301	270
2	2006	3.738	0.423	0.488	0.140	92.4	3.907	3.339	3.666	3.994	75.84	253	278	303	284
2	2007	3.800	0.400	0.479	0.137	90.1	4.161	3.182	3.509	3.837	75.55	240	265	290	287
2	2008	3.858	0.405	0.487	0.146	88.4	4.333	3.277	3.607	3.937	74.97	246	270	295	289
3	1999	4.546	0.466	0.566	0.151	94.7	3.120	3.992	4.330	4.667	71.61	286	310	334	326
3	2000	4.563	0.479	0.579	0.155	93.9	3.120	4.155	4.489	4.824	71.87	299	323	347	328
3	2001	4.348	0.470	0.600	0.129	94.8	3.128	4.066	4.401	4.736	72.43	294	319	343	315
3	2002	4.434	0.457	0.611	0.148	91.5	3.251	4.161	4.488	4.815	72.71	303	326	350	322
3	2003	4.381	0.460	0.604	0.168	93.6	3.160	4.158	4.492	4.826	72.81	303	327	351	319
3	2004	4.204	0.472	0.610	0.174	94.1	3.228	4.234	4.570	4.905	73.43	311	336	360	309
3	2005	4.205	0.451	0.588	0.168	88.3	3.316	4.197	4.524	4.850	73.24	307	331	355	308
3	2006	4.367	0.449	0.587	0.167	88.7	3.176	4.194	4.520	4.847	74.15	311	335	359	324
3	2007	4.226	0.455	0.594	0.184	88.7	3.205	4.298	4.625	4.952	74.93	322	347	371	317
3	2008	4.361	0.459	0.600	0.171	83.6	3.229	4.459	4.800	5.141	74.48	332	358	383	325
5	1999	4.908	0.468	0.613	0.195	87.1	2.952	4.576	4.908	5.240	70.27	322	345	368	345
5	2000	5.189	0.465	0.613	0.167	87.5	3.160	4.424	4.754	5.084	69.09	306	328	351	358
5	2001	5.039	0.478	0.619	0.174	89.1	3.231	4.477	4.807	5.137	69.38	311	333	356	350
5	2002	4.881	0.484	0.636	0.196	90.0	3.460	4.548	4.879	5.210	69.15	315	337	360	338
5	2003	4.885	0.482	0.620	0.165	91.3	3.487	4.354	4.682	5.010	69.40	302	325	348	339
5	2004	4.861	0.482	0.627	0.167	90.4	3.551	4.399	4.728	5.056	69.89	307	330	353	340
5	2005	4.774	0.479	0.626	0.166	91.7	3.700	4.303	4.630	4.957	69.88	301	324	346	334
5	2006	4.862	0.484	0.641	0.160	90.5	3.615	4.423	4.752	5.081	69.32	307	329	352	337
5	2007	5.091	0.484	0.656	0.167	87.6	3.551	4.599	4.935	5.272	69.12	318	341	364	352
5	2008	4.939	0.491	0.645	0.163	88.1	3.803	4.522	4.859	5.195	68.39	309	332	355	338
Predictions for California refineries															
California average, 2004			0.577	0.813	0.262	93.0	3.633	5.738	6.110	6.482	70.82	406	433	459	354
California average, 2005			0.575	0.811	0.260	95.0	3.801	5.603	5.979	6.355	71.06	398	425	452	358
California average, 2006			0.582	0.832	0.251	91.5	3.845	5.811	6.178	6.545	72.65	422	449	476	384
California average, 2007			0.582	0.843	0.259	88.3	3.814	5.985	6.354	6.722	71.43	428	454	480	401
California average, 2008			0.590	0.838	0.255	91.0	4.087	5.857	6.224	6.590	71.02	416	442	468	383
California average, 2009			0.595	0.830	0.252	82.9	4.045	6.122	6.501	6.880	70.54	432	459	485	397
BP Carson 2008			0.527	0.527	0.527	91.0	4.087	5.159	5.522	5.885	71.02	366	392	418	308
BP Carson 2009			0.527	0.527	0.527	82.9	4.045	5.450	5.804	6.158	70.54	384	409	434	302
Chevron El Segundo 2008			0.555	0.555	0.555	91.0	4.087	5.487	5.863	6.238	71.02	390	416	443	307
Chevron El Segundo 2009			0.547	0.547	0.547	82.9	4.045	5.681	6.043	6.404	70.54	401	426	452	273
Chevron Richmond 2008			0.453	0.453	0.453	91.0	4.087	4.257	4.595	4.934	71.02	302	326	350	340
Chevron Richmond 2009			0.453	0.453	0.453	82.9	4.045	4.543	4.878	5.212	70.54	320	344	368	321
CP Carson & Wilm. 2008			0.577	0.577	0.577	91.0	4.087	5.750	6.137	6.524	71.02	408	436	463	363
CP Carson & Wilm. 2009			0.577	0.577	0.577	82.9	4.045	6.044	6.419	6.794	70.54	426	453	479	320
ConocoPhillips Rodeo 2008			0.784	0.784	0.784	91.0	4.087	8.183	8.714	9.244	71.02	581	619	657	428
ConocoPhillips Rodeo 2009			0.784	0.784	0.784	82.9	4.045	8.484	8.996	9.508	70.54	598	635	671	425
ExxonMobil Torrance 2008			0.659	0.659	0.659	91.0	4.087	6.720	7.157	7.594	71.02	477	508	539	329
ExxonMobil Torrance 2009			0.656	0.656	0.656	82.9	4.045	6.977	7.397	7.816	70.54	492	522	551	311
Shell Martinez 2008			0.574	0.574	0.574	91.0	4.087	5.722	6.107	6.493	71.02	406	434	461	497
Shell Martinez 2009			0.628	0.628	0.628	82.9	4.045	6.656	7.059	7.462	70.54	470	498	526	514
Tesoro Avon 2008			0.894	0.894	0.894	91.0	4.087	9.459	10.08	10.71	71.02	672	716	760	313
Tesoro Avon 2009			0.894	0.894	0.894	82.9	4.045	9.762	10.36	10.97	70.54	689	731	774	276
Tesoro Wilmi./Carson 2008			0.620	0.620	0.620	91.0	4.087	6.262	6.674	7.086	71.02	445	474	503	376
Tesoro Wilmi./Carson 2009			0.620	0.620	0.620	82.9	4.045	6.558	6.956	7.354	70.54	463	491	519	341
Ultramar-Valero Wilm. 2008			0.575	0.575	0.575	91.0	4.087	5.729	6.115	6.501	71.02	407	434	462	287
Ultramar-Valero Wilm. 2009			0.575	0.575	0.575	82.9	4.045	6.023	6.397	6.771	70.54	425	451	478	293
Valero Benicia 2008			0.563	0.563	0.563	91.0	4.087	5.583	5.962	6.341	71.02	396	423	450	345
Valero Benicia 2009			0.563	0.563	0.563	82.9	4.045	5.876	6.244	6.613	70.54	414	440	466	357
California adjusted, 2004*			0.577	0.813	0.028	93.0	3.633	5.131	5.473	5.814	70.82	363	388	412	354
California adjusted, 2005*			0.575	0.811	0.028	95.0	3.801	5.004	5.348	5.691	71.06	356	380	404	358
California adjusted, 2006*			0.582	0.832	0.028	91.5	3.845	5.232	5.573	5.914	72.65	380	405	430	384
California adjusted, 2007*			0.582	0.843	0.028	88.3	3.814	5.379	5.726	6.072	71.43	384	409	434	401
California adjusted, 2008*			0.590	0.838	0.028	91.0	4.087	5.265	5.606	5.947	71.02	374	398	422	383
California adjusted, 2009*			0.595	0.830	0.028	82.9	4.045	5.523	5.893	6.262	70.54	390	416	442	397

Data from Table 2-1. * Adjusted by replacing observed gas oil/residua hydrotreating data with lowest value (PADD 1, 2006–2008).

In the context of emissions oversight and control, a metric that is biased-high can be considered a special case. It could cause serious problems if it is used as a benchmark to define "acceptable" emissions performance. Such a benchmark could erroneously define emissions that are greater than actual current emissions as acceptable, resulting in the allowance of excessive and potentially increasing emissions. If excess pollution caused by this "baseline inflation" problem were to occur, it would likely manifest as emissions oversight and control failure at the facility level.

Major refineries in the Los Angeles and Bay Area regions that collectively represent California fuels refining capacity were analyzed to assess the potential breadth and magnitude of this problem. Analysis was based on each facility's reported emissions and primary processing EQC based on reported process capacities for 2008 and 2009 (tables 2-5, 2-6). Reported emissions were compared with the 95% confidence of prediction lower bound for observations to assess the frequency of emissions baseline inflation that could remain undetected by the primary processing complexity metric. This lower bound of prediction exceeded reported annual refinery emissions in 18 of 22 cases, indicating the potential for widespread failure of emissions oversight and control.

To assess the magnitude of potential emissions that could be undetected by this complexity metric, reported emissions were compared with the its 95% confidence of prediction upper bound for observations. Individual facility annual emissions could increase above emissions reported for a refinery and year by more than 10% in 19 of 22 cases, and by more than 50% in ten of these cases, without exceeding the 95% confidence of prediction by this complexity metric.

Finally, the "adjusted" primary processing equivalent capacity prediction in Table 1-3 shows an example of how the decoupling of capacity from *EI* and emissions observed could explain this prediction error. This adjustment replaces observed California gas oil hydrotreating data with lowest value observed (PADD 1, 2006–2008). California's high gas oil hydrotreating capacity is consistent with maintaining light liquids yield from denser crude while meeting California's "clean fuels" standards. It also is likely to improve efficiencies of downstream processes via better pretreatment of their feeds: Gas oil hydrotreating removes sulfur and metals that poison catalysts in catalytic cracking and reforming processes *(1, 29, 38),* and is used for such pretreatment in California *(6).* Downstream process efficiency improvements may thereby offset emissions from California's extra gas oil hydrotreating. This adjustment thus represents a plausible, yet hypothetical,[3] scenario. Observed statewide emissions are exceeded by the lower bound of prediction in this hypothetical scenario by 3% in 1 of 6 years, and emissions are 5% below the central prediction as a six-year average (as compared with the 9–15% in 6 of 6 years and 14% six-year average without this adjustment; Table 1-3).

[3] Exact capacity/energy relationships cannot be verified because process-level material and energy inputs/outputs are not reported: therefore, this example may be one of multiple possible examples.

<u>Product yield output metric results</u>.
Figure 1-9 shows results for emissions intensity predicted by the primary products sum. The results show poor power of prediction (R^2 0.40) and poor reliability as well. Average observed California emissions exceed emissions predicted by this metric in 6 of 6 years and by 26–48% (Table 1–4).

Figure 1-9. Emission intensity predicted by the sum of ARB-proposed primary products

Prediction for California refineries on 1999–2008 data from U.S. refineries by nonparametric regression

R^2 0.40

Actual California refinery emissions in this period ranged from 354–401 kg/m³

Data from Table 1-4

- Observations for PADD 1, 2, 3 or 5
- Predictions for PADD 1, 2, 3 or 5
- Predictions for California 2004–2009

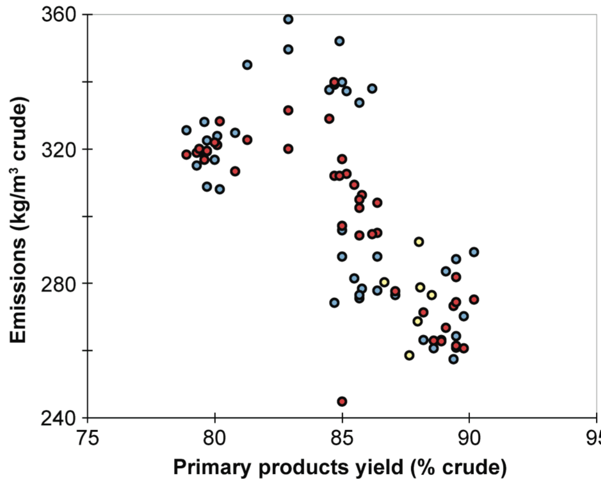


Figure 1-10 shows emissions intensity predicted by the primary liquids mix. Including fuel-specific yield instead of a lump sum, and excluding asphalt, improved the power of prediction substantially over the summing method (R^2 0.94), but California emissions exceeded the upper bound of prediction by 9–25% each year (Table 1-5).

Figure 1-10. Emisssions predicted by gasoline, distillate and jet fuel yield

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.94

Diagonal lines bound the 95% confidence of prediction for observations

Data from Table 1-5

- California annual average 2004–2009
- PADD 1, 2, 3 or 5 1999–2008

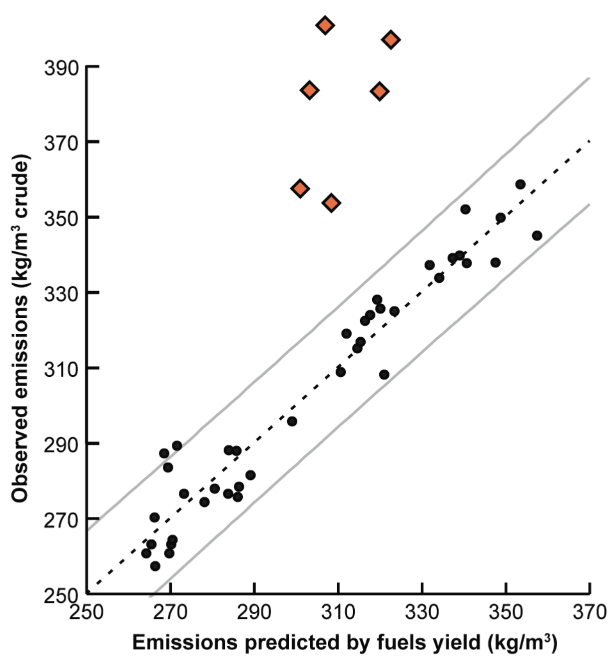


Table 1-4. Emissions predicted by primary products yield.[a]

		Inputs			*Results*		
		Observed CO_2	Primary products	Capacity utilization	Prediction	Observation	Obs–Pred.
PADD	Year	(kg/m^3)	(% crude)	(%)	(kg/m^3)	(kg/m^3)	%Δ
1	1999	281	85.50	90.9	309	281	-9
1	2000	276	85.70	91.7	302	276	-9
1	2001	288	86.40	87.2	295	288	-2
1	2002	278	86.40	88.9	304	278	-9
1	2003	274	84.70	92.7	340	274	-19
1	2004	278	85.80	90.4	306	278	-9
1	2005	277	87.10	93.1	278	277	0
1	2006	277	85.70	86.7	305	277	-9
1	2007	288	85.00	85.6	297	288	-3
1	2008	296	85.00	80.8	245	296	21
2	1999	263	88.20	93.3	271	263	-3
2	2000	261	88.60	94.2	263	261	-1
2	2001	263	88.90	93.9	263	263	0
2	2002	264	89.50	90.0	282	264	-6
2	2003	257	89.40	91.6	273	257	-6
2	2004	261	89.50	93.6	261	261	0
2	2005	270	89.80	92.9	261	270	4
2	2006	284	89.10	92.4	267	284	6
2	2007	287	89.50	90.1	274	287	5
2	2008	289	90.20	88.4	275	289	5
3	1999	326	78.90	94.7	318	326	2
3	2000	328	79.60	93.9	317	328	4
3	2001	315	79.30	94.8	319	315	-1
3	2002	322	79.70	91.5	319	322	1
3	2003	319	79.40	93.6	320	319	0
3	2004	309	79.70	94.1	319	309	-3
3	2005	308	80.20	88.3	328	308	-6
3	2006	324	80.10	88.7	321	324	1
3	2007	317	80.00	88.7	322	317	-2
3	2008	325	80.80	83.6	313	325	4
5	1999	345	81.30	87.1	323	345	7
5	2000	358	82.90	87.5	320	358	12
5	2001	350	82.90	89.1	331	350	5
5	2002	338	84.50	90.0	329	338	3
5	2003	339	84.70	91.3	312	339	9
5	2004	340	85.00	90.4	317	340	7
5	2005	334	85.70	91.7	294	334	13
5	2006	337	85.20	90.5	313	337	8
5	2007	352	84.90	87.6	312	352	13
5	2008	338	86.20	88.1	294	338	15
Calif. avg.	2004	354	86.68	93.0	280	354	26
Calif. avg.	2005	358	87.66	95.0	259	358	38
Calif. avg.	2006	384	88.07	91.5	279	384	38
Calif. avg.	2007	401	88.04	88.3	292	401	37
Calif. avg.	2008	383	88.53	91.0	276	383	39
Calif. avg.	2009	397	87.98	82.9	269	397	48

[a] Observed emissions analyzed against the sum of yield for aviation gasoline, motor gasoline, distillate fuel oil, kerosene jet fuel, and asphalt by nonparametric regression (LOWESS). Data from Table 2-1.

Table 1-5. Emissions predicted by primary liquid products; PLS regression[a]

		Inputs					*Results*					
		Obs. CO_2	Gasol-	Jet kero-	Distill-	Capac.	Emit pred. 95% confidence			Obs.	Δ	Fuels emit
PADD	Year	(kg/m^3)	ine (%)	sene (%)	ate (%)	ut. (%)	Lower	Central	Upper	(kg/m^3)	(%)	(kg/m^3)[b]
1	1999	281	46.6	7.0	26.3	90.9	275	289	303	281	0	234
1	2000	276	45.2	6.3	27.9	91.7	272	286	300	276	0	234
1	2001	288	45.8	5.3	29.1	87.2	270	284	298	288	0	238
1	2002	278	46.7	5.3	28.1	88.9	267	281	295	278	0	237
1	2003	274	46.4	5.2	27.2	92.7	264	278	292	274	0	233
1	2004	278	46.5	6.1	26.6	90.4	273	286	300	278	0	234
1	2005	277	46.6	5.7	28.8	93.1	260	273	287	277	0	240
1	2006	277	45.8	5.1	29.2	86.7	270	284	298	277	0	236
1	2007	288	45.5	5.0	29.4	85.6	272	286	300	288	0	236
1	2008	296	44.6	5.7	29.6	80.8	284	299	314	296	0	236
2	1999	263	51.1	6.6	24.8	93.3	256	270	284	263	0	241
2	2000	261	50.4	6.9	25.7	94.2	256	270	284	261	0	242
2	2001	263	51.1	6.6	26.0	93.9	251	266	280	263	0	245
2	2002	264	52.0	6.7	25.4	90.0	257	271	285	264	0	245
2	2003	257	51.5	6.2	26.0	91.6	252	266	280	257	0	245
2	2004	261	51.6	6.4	25.7	93.6	250	264	279	261	0	245
2	2005	270	50.4	6.5	27.1	92.9	252	266	280	270	0	246
2	2006	284	49.4	6.2	27.3	92.4	256	270	283	284	0	243
2	2007	287	49.8	6.1	28.2	90.1	255	269	282	287	2	246
2	2008	289	48.5	6.3	30.0	88.4	258	272	286	289	1	249
3	1999	326	44.8	11.1	21.1	94.7	306	320	334	326	0	220
3	2000	328	44.7	11.1	21.9	93.9	306	319	333	328	0	222
3	2001	315	44.3	10.5	22.8	94.8	301	315	328	315	0	223
3	2002	322	45.4	10.3	22.3	91.5	303	317	330	322	0	223
3	2003	319	44.8	9.9	23.0	93.6	298	312	326	319	0	223
3	2004	309	44.6	10.0	23.5	94.1	297	311	324	309	0	225
3	2005	308	43.8	10.2	24.5	88.3	307	321	335	308	0	226
3	2006	324	43.5	9.7	25.2	88.7	304	318	332	324	0	226
3	2007	317	43.2	9.4	26.0	88.7	302	315	329	317	0	227
3	2008	325	41.6	9.6	28.4	83.6	309	323	338	325	0	230
5	1999	345	44.7	15.8	18.3	87.1	343	357	372	345	0	219
5	2000	358	45.7	16.2	18.5	87.5	339	353	368	358	0	223
5	2001	350	45.5	16.0	19.2	89.1	335	349	363	350	0	224
5	2002	338	47.3	16.0	19.0	90.0	327	341	355	338	0	229
5	2003	339	47.2	16.0	19.5	91.3	323	337	351	339	0	230
5	2004	340	47.3	16.2	19.5	90.4	325	339	353	340	0	231
5	2005	334	47.3	16.2	20.4	91.7	320	334	348	334	0	233
5	2006	337	47.7	15.3	20.3	90.5	318	332	346	337	0	233
5	2007	352	46.6	15.6	20.8	87.6	327	340	354	352	0	232
5	2008	338	45.6	17.5	21.6	88.1	334	348	362	338	0	235
Calif. avg.	2004		53.4	13.7	17.3	93.0	294	308	323	354	9	237
Calif. avg.	2005		53.3	13.6	18.8	95.0	286	301	316	358	13	241
Calif. avg.	2006		53.9	13.3	18.7	91.5	289	303	318	384	21	242
Calif. avg.	2007		53.7	12.9	19.2	88.3	293	307	321	401	25	242
Calif. avg.	2008		50.6	15.7	20.6	91.0	306	320	334	383	15	243
Calif. avg.	2009		53.5	14.3	18.7	82.9	309	323	336	397	18	242

[a] Observed emissions vs motor gasoline, distillate, and jet kerosene yield with refinery capacity utilization analyzed by partial least squares (PLS) regression. Data from Table 2-1.

[b] NETL estimated average refinery emissions of 46.0, 50.8, and 30.5 kg/barrel conventional gasoline, diesel, and kerosene produced, respectively *(32)*. These estimates are applied to total yields of gasoline, distillate and kerosene *(Table 2-1)* to estimate emissions that can be explained by production of these fuels in each region and year ("fuels" emit").

The prior analyses tested the metric's ability to predict energy or emissions intensities as an explanatory or *x* variable. The next two analyses test the products-based metric's stability as a measurement that is predictable in relation to other factors (as a *y* variable).

Figure 1-11 presents results for the case where the products metric includes all products and is predicted by crude feed quality. Results suggest good power of prediction (R^2 0.90), and much less error of California predictions than observed in the product metrics that exclude crude feed quality, but observed California emissions still exceed the prediction in all cases by 6–17%.

Figure 1-11. Emission intensity predicted by total products yield and oil quality, nonparametric regression

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.90
Predictions and observations for all parameters plotted against density

Data from Table 1-6

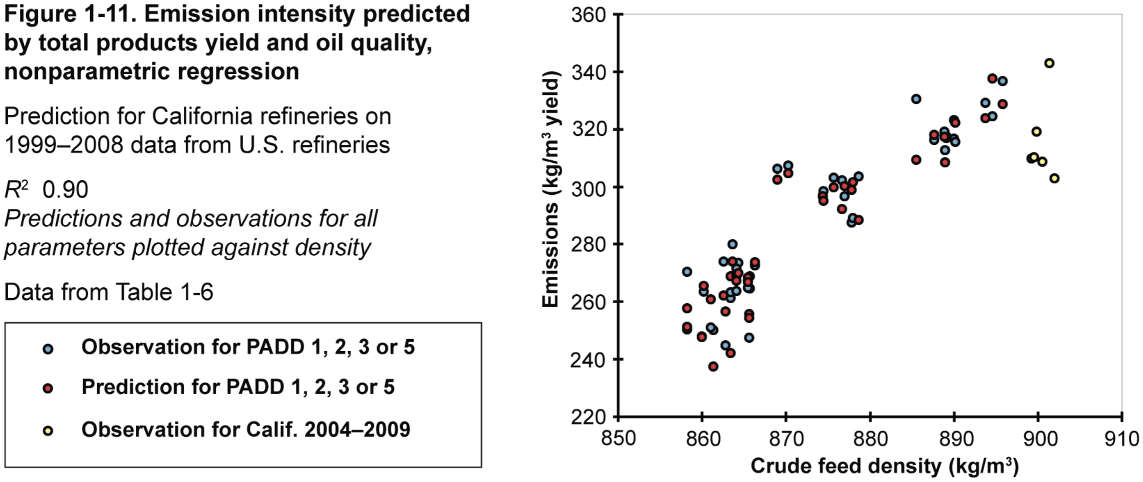


Figure 1-12 presents results where the products metric includes light liquids (aviation and motor gasoline, jet kerosene, distillate and naphtha) and is predicted by crude feed quality. Power of prediction is good (R^2 0.91), and California observations fall within the prediction in 2 years but exceed the prediction by 4–7% during four years.

Figure 1-12. Emissions/product output predicted by crude feed quality

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.91

Diagonal lines bound the 95% confidence of prediction for observations

aviation gasoline, motor gasoline, jet fuel, distillate and naphtha

Data from tables 1-7 and 2-1

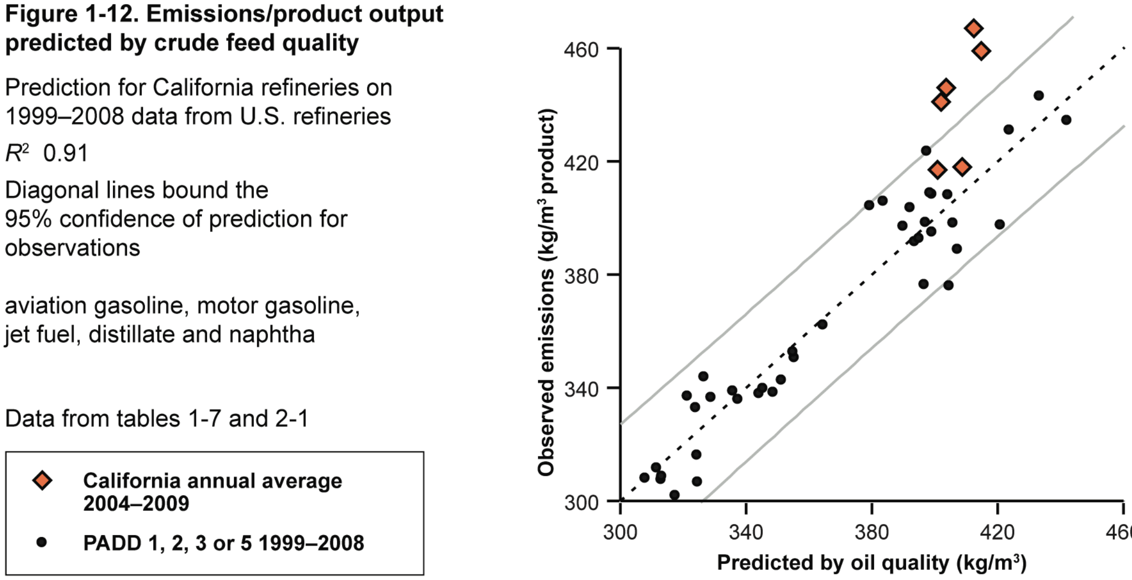


Table 1-6. Emissions/total products predicted by crude feed quality

Emit/prod: products include all products

PADD	Year	Emit/TotProd (kg/m^3)	density (kg/m^3)	sulfur (kg/m^3)	Cap. ut. (%)	Prod. ratio	Prediction (kg/m^3)	Observed (kg/m^3)	Obs-Pred %Δ
1	1999	270.2	858.20	8.24	90.9	3.668	258	270	5
1	2000	263.5	860.18	8.00	91.7	3.489	265	263	-1
1	2001	272.4	866.34	7.71	87.2	3.479	274	272	0
1	2002	264.5	865.71	7.45	88.9	3.605	269	265	-2
1	2003	261.1	863.44	7.43	92.7	3.321	269	261	-3
1	2004	264.8	865.44	7.79	90.4	3.397	268	265	-1
1	2005	263.1	863.38	7.17	93.1	3.756	242	263	9
1	2006	263.6	864.12	7.17	86.7	3.522	269	264	-2
1	2007	273.4	864.33	7.26	85.6	3.443	270	273	1
1	2008	280.0	863.65	7.08	80.8	3.400	274	280	2
2	1999	250.3	858.25	10.64	93.3	4.077	251	250	0
2	2000	247.8	860.03	11.35	94.2	4.132	248	248	0
2	2001	250.1	861.33	11.37	93.9	4.313	237	250	5
2	2002	251.0	861.02	11.28	90.0	4.345	261	251	-4
2	2003	244.8	862.80	11.65	91.6	4.281	256	245	-5
2	2004	247.4	865.65	11.86	93.6	4.167	256	247	-3
2	2005	255.6	865.65	11.95	92.9	4.207	254	256	1
2	2006	267.5	865.44	11.60	92.4	3.907	267	267	0
2	2007	271.4	864.07	11.84	90.1	4.161	267	271	2
2	2008	273.9	862.59	11.73	88.4	4.333	262	274	5
3	1999	306.2	869.00	12.86	94.7	3.120	302	306	1
3	2000	307.3	870.29	12.97	93.9	3.120	305	307	1
3	2001	296.8	874.43	14.34	94.8	3.128	297	297	0
3	2002	302.1	876.70	14.47	91.5	3.251	292	302	3
3	2003	298.4	874.48	14.43	93.6	3.160	295	298	1
3	2004	287.4	877.79	14.40	94.1	3.228	299	287	-4
3	2005	288.9	878.01	14.40	88.3	3.316	301	289	-4
3	2006	302.9	875.67	14.36	88.7	3.176	300	303	1
3	2007	296.5	876.98	14.47	88.7	3.205	300	296	-1
3	2008	303.6	878.66	14.94	83.6	3.229	288	304	5
5	1999	324.5	894.61	11.09	87.1	2.952	337	324	-4
5	2000	336.6	895.85	10.84	87.5	3.160	329	337	2
5	2001	329.2	893.76	10.99	89.1	3.231	324	329	2
5	2002	316.6	889.99	10.86	90.0	3.460	323	317	-2
5	2003	317.4	889.10	10.94	91.3	3.487	317	317	0
5	2004	319.0	888.87	11.20	90.4	3.551	317	319	1
5	2005	312.7	888.99	11.38	91.7	3.700	308	313	1
5	2006	316.2	887.65	10.92	90.5	3.615	318	316	-1
5	2007	330.4	885.54	11.07	87.6	3.551	309	330	7
5	2008	315.4	890.16	12.11	88.1	3.803	322	315	-2
Predictions for California refineries									
California average, 2004			899.23	11.46	93.0	3.633	310	328	6
California average, 2005			900.56	11.82	95.0	3.801	309	330	7
California average, 2006			899.56	11.73	91.5	3.845	310	354	14
California average, 2007			899.84	11.89	88.3	3.814	319	370	16
California average, 2008			902.00	12.85	91.0	4.087	303	354	17
California average, 2009			901.38	11.70	82.9	4.045	343	368	7

Data from Table 2-1.

Table 1-7. Emissions/product output predicted by crude feed quality

Emit/prod: products include aviation and motor gasoline, jet fuel, distillate, and naphtha

PADD	Year	Emit/prod. (kg/m^3)	density (kg/m^3)	sulfur (kg/m^3)	Cap. ut. (%)	Prod. ratio	Emit pred. 95% confidence Lower	Central	Upper	Observed (kg/m^3)
1	1999	344	858.20	8.24	90.9	3.668	304	326	348	344
1	2000	339	860.18	8.00	91.7	3.489	313	335	357	339
1	2001	351	866.34	7.71	87.2	3.479	333	355	377	351
1	2002	338	865.71	7.45	88.9	3.605	322	344	366	338
1	2003	340	863.44	7.43	92.7	3.321	323	345	367	340
1	2004	343	865.44	7.79	90.4	3.397	329	351	373	343
1	2005	333	863.38	7.17	93.1	3.756	301	324	346	333
1	2006	338	864.12	7.17	86.7	3.522	326	348	370	338
1	2007	353	864.33	7.26	85.6	3.443	333	354	376	353
1	2008	362	863.65	7.08	80.8	3.400	342	364	386	362
2	1999	312	858.25	10.64	93.3	4.077	289	311	334	312
2	2000	308	860.03	11.35	94.2	4.132	290	313	335	308
2	2001	308	861.33	11.37	93.9	4.313	285	307	330	308
2	2002	309	861.02	11.28	90.0	4.345	290	313	335	309
2	2003	302	862.80	11.65	91.6	4.281	295	317	339	302
2	2004	307	865.65	11.86	93.6	4.167	302	324	346	307
2	2005	316	865.65	11.95	92.9	4.207	302	324	346	316
2	2006	336	865.44	11.60	92.4	3.907	315	337	359	336
2	2007	337	864.07	11.84	90.1	4.161	306	328	351	337
2	2008	337	862.59	11.73	88.4	4.333	299	321	343	337
3	1999	404	869.00	12.86	94.7	3.120	357	379	401	404
3	2000	406	870.29	12.97	93.9	3.120	361	383	405	406
3	2001	392	874.43	14.34	94.8	3.128	371	393	415	392
3	2002	395	876.70	14.47	91.5	3.251	377	399	421	395
3	2003	393	874.48	14.43	93.6	3.160	372	394	416	393
3	2004	376	877.79	14.40	94.1	3.228	374	396	418	376
3	2005	376	878.01	14.40	88.3	3.316	382	404	426	376
3	2006	398	875.67	14.36	88.7	3.176	383	405	427	398
3	2007	389	876.98	14.47	88.7	3.205	385	407	429	389
3	2008	398	878.66	14.94	83.6	3.229	398	420	443	398
5	1999	434	894.61	11.09	87.1	2.952	419	442	464	434
5	2000	443	895.85	10.84	87.5	3.160	410	433	455	443
5	2001	431	893.76	10.99	89.1	3.231	401	423	446	431
5	2002	408	889.99	10.86	90.0	3.460	382	404	426	408
5	2003	408	889.10	10.94	91.3	3.487	377	399	421	408
5	2004	409	888.87	11.20	90.4	3.551	376	398	420	409
5	2005	397	888.99	11.38	91.7	3.700	368	390	411	397
5	2006	404	887.65	10.92	90.5	3.615	370	392	414	404
5	2007	423	885.54	11.07	87.6	3.551	375	397	419	423
5	2008	398	890.16	12.11	88.1	3.803	375	397	419	398
Predictions for California refineries										
California average, 2004			899.23	11.46	93.0	3.633	387	409	431	418
California average, 2005			900.56	11.82	95.0	3.801	379	401	423	417
California average, 2006			899.56	11.73	91.5	3.845	382	404	426	446
California average, 2007			899.84	11.89	88.3	3.814	390	412	435	467
California average, 2008			902.00	12.85	91.0	4.087	380	402	424	441
California average, 2009			901.38	11.70	82.9	4.045	393	415	437	459

Data from Table 2-1.

Estimates of emissions explained directly by fuels production ("fuels emit" in Table 1-5) are smaller (219–249 vs 257–401 kg/m^3) and range much less (30 vs 144 kg/m^3) than observed emissions. Further, among PADDs, emissions explained by fuels production trend downward as those predicted based on product fuels output, and those observed, trend upward (Table 1-5). Thus, the relative amounts of motor fuel products outputs cannot explain observed emissions, trends in observed emissions, or trends in the predictions based on the mix of primary liquid fuels. Therefore, the prediction error shown in Figure 1-10 must be explained by this prediction (erroneously) equating California refineries to those in other regions that have a similar mix of fuel product yields but very different (in this case lower) refinery emission intensities.

Accounting for crude feed quality in the emissions/volume products metric clearly reduces the errors of its predictions for California observations by substantial amounts (compare figures 1-11, 1-12 with 1-9, 1-10). This was already known from the crude feed quality metric results, because that metric includes products data alongside density, sulfur, and capacity utilization. What is new is that the results for the two methods including fuels product output and crude feed quality are not the same.

Comparison of the results in tables 1-6 and 1-7 with those for the crude feed quality metric results (Table 1-1) provides information about the emissions/volume products metric because it is the only variable that differs from the crude feed quality metric. It replaces emission/volume crude as the y variable. Different product slates can be made from the same crude feed. Also, depending upon the crude feed, product, and processing intensity, volume expansion of products over crude (yield "gain" on crude) can result in some variance in products volumes as compared with crude feeds. Thus, the emission/vol. products value can change with changes in fuel products volume that may not change the emission/vol. crude value as much or may not be associated with a change in crude feed volume. Evidence for this is observed in the data set analyzed here.

Low products ratio values for PADD 3 in 2008 and PADD 5 1999–2001 (Table 1-7) drove emissions/vol. product assigned to those regions and years higher than California values. This changed the distribution of observed emission values, which affected the prediction, and pushed the California predictions in Figure 1-12 to the left (compare with Figure 1-5). Had that not happened, the predictions for California refineries shown in Figure 1-12 might appear very good instead of fairly poor.

These results suggest instability of the emissions/vol. product metric as an emission performance benchmark: it reports emission intensity values that may be overly sensitive to changes in product volume. Facility-level variability is significantly greater than variability between refining regions in general, suggesting that errors for individual facilities are likely to be larger than those found here from statewide and U.S. regional averages. These considerations further highlight the need to resolve unanswered questions about facility-level reporting of products data.

Discussion

Data gathered from California refineries, though limited by poor facility-level reporting and poor accessibility that limited the California data gathered to six years, add information to the nationwide refining performance picture. Comparison with the U.S. data (Table 2-1) shows that average California refinery CO_2 emission intensity is at the high extreme among regions, exceeding that of PADD 3 by 20% and that of PADD 2 by 38%, based on the six most recent years for each region. The decoupling of conversion capacity from energy intensity is also more extreme in California, where product fuels yield stays relatively flat as crude feed density and energy intensity increments remain coupled (Figure 1-4), adding regional detail to the relationship of feedstock and products with refinery fuel combustion rates. The California data, presented in one place for the first time, can support additional analysis beyond the scope of the present assessment. Here the California data together with the U.S. data support observations for analysis of emissions performance metrics.

This assessment treats each refinery emissions performance metric option as an hypothesis—refinery emission intensity can be measured and predicted accurately and reliably by this metric—and tests the hypothesis against real world observations from refineries in actual operation. Table 1-8 summarizes the results from analysis of alternative metric options for their ability to measure and predict refinery CO_2 emissions intensity accurately and reliably.

The very poor R-squared value for refinery equivalent capacity (0.35) indicates that this complexity metric is not related to observed emission intensity. Among the remaining metrics, large differences between observed California emissions and those predicted by the metric on average over the six years of record (six-yr %Δ) show that metrics which exclude crude feed quality do not measure and predict California refinery emissions accurately or reliably.

Primary processing capacity is consistently (100% outlier rate) and substantially (six-yr %Δ –14%) biased high. This reflects the more extreme decoupling of conversion capacity from energy intensity in California, and is exacerbated by the correlation of this complexity metric with emissions (R^2 0.92). That correlation is expected because primary processing capacity enables lower quality crude feeds, but capacity can be used in different ways with different energy and emission effects, as shown by the California observations (Figure 1-4). As an emissions benchmark, this complexity metric assumes process capacity equates to emissions when it does not. Benchmarking emissions by this metric could artificially assign "good" performance to California refineries that, in the real world, are at the high extreme of emissions intensity.

Excluding crude feed quality from the products-based approach, the CO_2/vol. product fuels metric has the highest prediction error among these metrics (six-yr %Δ +22%) and a 100% outlier rate. Production of the fuels targeted by this metric is causally linked to refinery energy and emission commitments *(3, 4, 31–35).* However, crude quality effects on processing vary more than those of products *(1),* and the association of hydrogen

Table 1-8. Summary of benchmark option performance on U.S. refinery data (1999–2008) and comparison to California annual average observations (2004–2009).

%Δ: difference of observation from prediction, in percent

			comparison with 95% confidence of prediction		
		prediction	outlier	magnitude of prediction error	
benchmark option	R^2	six-yr %Δ	rate (%)	minimum %Δ	maximum %Δ
crude quality & product ratio	0.90	< 1	33	0	1
refinery equivalent capacity	0.35	–5	0	0	0
primary processing eq. cap.	0.92	–14	100	–9	–15
CO_2/vol. product fuels	0.94	22	100	9	25
CO_2/vol. fuels & crude qual.	0.91	8	66	0	7

Fuels are gasolines, distillate, jet kerosene and naphtha. Product ratio is the ratio by volume of these fuels to other refinery products. Equivalent capacity is the capacity of specified processes relative to that of atmospheric crude distillation and is the most widely used basis for refinery complexity metrics. Predictions and California observations for emissions summarized from tables 1-1, 1-2, 1-3, 1-5 and 1-7. Prediction six-yr %Δ is the difference of observation from the central prediction averaged across the six years of data. Minimum and maximum %Δ are the min. and max. excess of observation from the confidence of prediction.

production emissions with crude feed quality and hydrocracking rather than product hydrotreating found nationally *(1)* is observed in California as well (figures 1-2, 1-3). Much better results for the remaining metrics, which include crude feed quality and products, confirm that excluding crude feed quality causes most of the problem with the products-only metric.

The CO_2/vol. fuels & crude quality metric (outlier rate 66%; six-yr %Δ 8%) is less reliable than the crude quality & product ratio metric (outlier rate 33%; six-yr %Δ < 1%) because it includes products volume in its emissions term. This makes the stability of its emission performance value vulnerable to product slate variability that is unrelated to actual emissions. Unfortunately, that problem will likely be worse at the facility level than it appears in the multi-facility averages shown in Table 1-8, and will likely be exacerbated by unresolved questions of transparency and reporting of products data.

Including crude feed quality with light liquid fuels product output, and assigning neither causal component to the emissions intensity term—as is done in the crude quality & products ratio metric—is the more accurate and reliable approach among the metrics assessed. This feedstock-and-products approach also has the strongest causal support.

Making light liquid fuels from the denser, more contaminated components of crude requires aggressive processing to reject carbon and inject hydrogen, and supporting processes that also consume energy. More of the lower quality crude barrel is comprised of these denser, more contaminated components; putting more of the barrel through carbon rejection and aggressive hydrogen addition processing requires more energy to refine each barrel. This extra energy requires burning more fuel. That emits more combustion products at refineries. Thus, observed relationships among crude feed quality, the ratio of light liquids to other refinery products, and refinery capacity utilization can measure and predict impacts of those causal factors on emissions.

Crude feed quality explains 90% of energy intensity and 85% of CO_2 emission intensity differences observed among the four largest U.S. refining regions over ten years. Emissions predicted by crude density, crude sulfur content, products ratio, and capacity utilization explain most of the regional differences among government estimates of refinery emissions. CO_2 emissions can be measured and predicted for groups of refineries with diverse feeds by these four parameters *(1).*

A larger, and crucial, reason for benchmarking refinery emissions performance against crude feed quality along with fuels product output is that California refineries are switching crude supplies. Government projections *(18),* industry projections *(19),* and the long, continuing decline in California crude production observed since the mid-1980s *(5, 44)* all indicate that 70–76% of the California refinery crude feed will *not* be from current in-state sources by 2020. Declining production from Alaska's currently-tapped fields *(18, 19)* and the ease of switching among foreign supplies mean that, in practical terms, up to three-quarters of the 2020 crude feed will be "new." Therefore, despite the large planning and capital equipment costs typically incurred to re-tune refineries for crude feed of different quality, an acceleration of the currently observed refinery retooling trend is foreseeable in California because of the *need* to switch crude supplies. The choice among supplies that could plausibly range from current PADD 1 crude feed quality (863.9 kg/m^3 density, 7.17 kg/m^3 sulfur, 2005–2008 data from Table 2-1) to that of the average heavy oil (957.4 kg/m^3 density, 27.8 kg/m^3 sulfur) *(28)* is being made now.

Whether business or policy choices lead California refineries to compete on the global crude market for lower or higher quality crude for this new supply could affect emissions dramatically. Recently published work predicts that a switch from conventional crude to heavy oil/natural bitumen blends could double or triple U.S. refinery emissions *(1).* Replacing 70% of current (2009) statewide refinery crude input with heavy oil (central prediction, Table S8 in ref. 1) could boost average California refinery emissions to about 573 kg/m^3, an increase of approximately 44% or 17 million tonnes/year. Based on the same prediction model *(1)* and the average California refinery products, capacity usage and fuels data from Table 2-1, replacing that 70% with current PADD 1 average crude could cut average California refinery emissions to about 318 kg/m^3, a reduction of 20% or ~8 million tonnes/year (2005–2008 data, Table 2-1). Intermediate scenarios are certainly possible, but it should be noted that these examples exclude the worst-case emissions increase that might occur if the industry switches to tar sands bitumen.

Comparison of these potential emissions changes to the 10% cut in refinery emissions envisioned by 2020 via product fuels switching under California's Low Carbon Fuel Standard shows that the crude switch happening now could overwhelm other emissions control efforts for much better, or much worse. Further, the new crude slate will likely be locked in over the next, decades-long, refinery capital equipment cycle by the sunk costs in equipment retooled for the feed quality chosen. Again, this choice is being made now. California's refinery emissions performance benchmark could succeed if it addresses crude quality effects on emissions and will likely fail if it does not.

Recommendations

1. Expand refinery crude feed quality reporting to include crude oil from U.S. sources.

   Currently, every refinery in the U.S. reports the volume, density, and sulfur content of every crude oil shipment it processes, and that is public—but only for foreign crude. (www.eia.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html) The quality of crude refined from wells on U.S. soil is exempted. Since California's major fuels refineries use U.S. crude too, this hides facility feedstock quality from the public and from publicly verifiable environmental science. The public has a right to know about how U.S. oil creates pollution of our communities and threatens our climate. State and federal officials should ensure that the U.S. crude refined is reported just like the foreign crude refined. This is critical for California now.

2. Benchmark refinery performance against nationwide performance.

   Average California refinery emissions intensity exceeds that of any U.S. refining region. It is at the high-emission extreme of performance, not any acceptable norm. It need not remain so, because the main cause of its high emission intensity, refining lower quality crude, can change. California refining has begun a switch to new sources of crude that will play out in the form of new commitments to lower-carbon, similar, or higher-carbon intensity crude feeds before 2020. Thus, "grandfathering" its high emission intensity is unnecessary and risks excess or increased emissions.

3. The benchmark emission component should be a direct emission measurement.

   Emission estimates based on measurements elsewhere that are applied to unmonitored emission sources are prone to error. Comprehensive direct sampling of emission streams provides more accurate and reliable measurements. It should be used. Until then, emission estimates should be based on publicly verifiable data for fuel types, amounts, and emission factors. Importantly, CO_2 predominates the global warming potential (CO_2e) of refinery emissions, and emission factor-based estimates for CO_2 are prone to smaller errors than those for smaller and proportionately more variable portions of combustion product streams. Those considerations and the need for action are balanced with the need for accuracy in this recommendation.

4. The benchmark must measure the driving cause(s) of emission intensity change.

   Benchmarks that fail to measure a driving cause of emissions performance risk emission control failure and perverse results that worsen emissions. Failing to measure the emission intensity driver may track performance inaccurately, miss problems caused by that unmeasured factor, or even mistakenly assign good performance to poor performance caused by that driving factor. Measuring the causal factor(s) driving differences in refinery emission intensity tracks performance more accurately and identifies (predicts) actions needed to maintain and improve emission performance more reliably. All of these benefits, or all of these problems, could be realized depending on which of the currently available benchmark options is chosen.

5. Benchmark refinery emissions intensity against crude feed quality *and* fuels product.

   Crude feed quality is the major driver of refinery emissions intensity in California and the U.S. It explains 85% of emissions variability among U.S. refining regions, and predicts average California refinery emissions within 1% over six recent years. This metric can be used to separate out the major impact of crude quality so that other factors affecting emissions are better identified and addressed, to reduce emissions via refinery feedstock measures analogous to those limiting electric power generation from coal in California, or both. Crude feed quality and fuels produced is the most powerful and reliable of the metrics assessed for refinery emissions.

6. An equipment capacity (complexity) benchmark should not be used in California.

   Metrics based on a refinery's processing capacity or "complexity" greatly exaggerate California refineries' already-high emission intensity. A major reason is that these equipment capacity-based metrics, which were not designed to measure emission intensity, commit the error of attempting to account for California refineries' extra conversion capacity as if it were the same as emission intensity. As a benchmark, this metric would make California refineries' extreme-high emission intensity appear to be good performance, and encourage refiners to install even more capacity for higher-carbon crude, which could further increase emissions.

7. Products-based benchmarks have reliability problems when crude quality is excluded.

   The most accurate and reliable benchmark option assessed includes fuels product output with crude feed quality and a stable emission intensity term. Product-based metrics that exclude crude quality do not measure and predict emissions accurately or reliably. Including product volume in the emission term makes the emission performance measurement unstable, but this problem is readily resolved by including the fuels product and crude quality drivers in the metric side-by-side (see recs. 5, 8). Asphalt should be separated out from light liquid fuels, as these are different classes of products. Public reporting of each facility's products should be addressed.

8. Establish benchmarks and monitor performance using publicly reported data.

   Refinery performance can be measured and predicted based on publicly reported data. A benchmark that relies on secret data would violate basic scientific principles, be prone to the error secrecy breeds, and ultimately violate the environmental policy test that requirements imposed must have scientific support.

   The crude feed quality and fuels produced metric proposed herein measures and predicts emissions per barrel crude refined based on the density and sulfur content of crude feeds, refinery capacity utilization, and the ratio of light liquids (gasoline, distillate, kerosene and naphtha) to other refinery products. It is based on data for U.S. refining districts 1, 2, 3 and 5 over ten recent years. Energy intensity expected from these parameters is compared with fuels data using CO_2 emission factors developed for international reporting of greenhouse gas emissions in the U.S. Data and methods are freely available at http://pubs.acs.org/doi/abs/10.1021/es1019965.

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Part 2. Data.

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Table 2-1. Oil refining data, California (2004–2009); U.S. PADDs 1, 2, 3 and 5 (1999–2008)

California refineries		Refinery crude inputs: Feed volume ($m^3/d \times 10^3$)	Density (kg/m^3)	Sulfur (kg/m^3)	Source countries	Refinery process capacity: Atm. dist. ($m^3/d \times 10^3$)	Vacuum dist. ($m^3/d \times 10^3$)	Coking & therm. ($m^3/d \times 10^3$)
Calif.	2004	285.239	899.23	11.46	20	306.623	177.001	77.331
Calif.	2005	293.702	900.56	11.82	24	309.167	177.621	77.729
Calif.	2006	285.519	899.56	11.73	22	312.028	181.548	77.967
Calif.	2007	278.419	899.84	11.89	26	315.288	183.535	79.573
Calif.	2008	285.636	902.00	12.85	23	313.972	185.093	78.452
Calif.	2009	263.568	901.38	11.70	21	318.010	189.099	78.611
Energy factor		--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)			--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery crude inputs: Feed volume ($m^3/d \times 10^3$)	Density (kg/m^3)	Sulfur (kg/m^3)	Source countries	Refinery process capacity: Atm. dist. ($m^3/d \times 10^3$)	Vacuum dist. ($m^3/d \times 10^3$)	Coking & therm. ($m^3/d \times 10^3$)
1	1999	244.363	858.20	8.24	24	243.648	98.020	14.198
1	2000	247.543	860.18	8.00	23	245.922	97.213	14.404
1	2001	235.460	866.34	7.71	19	249.578	96.577	14.086
1	2002	242.456	865.71	7.45	20	252.217	97.424	14.420
1	2003	251.836	863.44	7.43	21	250.750	99.745	14.484
1	2004	249.610	865.44	7.79	21	250.246	99.741	14.484
1	2005	254.221	863.38	7.17	22	252.631	101.497	14.484
1	2006	236.255	864.12	7.17	21	252.631	101.490	14.484
1	2007	234.188	864.33	7.26	24	252.631	101.490	14.484
1	2008	221.151	863.65	7.08	24	252.631	101.490	14.484
2	1999	536.264	858.25	10.64	15	570.946	232.722	58.801
2	2000	542.147	860.03	11.35	16	569.841	236.251	60.978
2	2001	526.089	861.33	11.37	15	564.271	229.892	61.312
2	2002	511.621	861.02	11.28	20	557.754	225.920	56.983
2	2003	512.575	862.80	11.65	16	555.868	226.693	56.122
2	2004	524.817	865.65	11.86	20	555.281	229.605	58.178
2	2005	526.884	865.65	11.95	23	564.648	236.887	59.623
2	2006	526.089	865.44	11.60	20	565.065	238.954	59.480
2	2007	514.801	864.07	11.84	17	578.730	231.688	60.315
2	2008	515.755	862.59	11.73	16	579.803	234.657	59.226
3	1999	1,116.890	869.00	12.86	33	1,234.340	575.734	154.933
3	2000	1,130.240	870.29	12.97	31	1,234.360	591.069	164.981
3	2001	1,156.000	874.43	14.34	28	1,236.250	581.572	173.182
3	2002	1,127.860	876.70	14.47	33	1,258.170	574.493	187.174
3	2003	1,160.130	874.48	14.43	30	1,268.770	584.170	193.899
3	2004	1,191.450	877.79	14.40	33	1,280.320	604.415	200.467
3	2005	1,145.350	878.01	14.40	36	1,323.230	596.821	198.973
3	2006	1,172.530	875.67	14.36	41	1,333.830	598.501	201.898
3	2007	1,176.820	876.98	14.47	37	1,341.890	610.544	209.377
3	2008	1,118.790	878.66	14.94	36	1,337.700	614.105	210.458
5	1999	419.726	894.61	11.09	24	494.843	231.722	95.944
5	2000	430.856	895.85	10.84	23	498.357	231.523	97.144
5	2001	442.621	893.76	10.99	26	495.424	236.920	97.574
5	2002	447.867	889.99	10.86	27	484.218	234.193	98.337
5	2003	456.612	889.10	10.94	29	489.237	235.966	96.712
5	2004	454.863	888.87	11.20	28	487.232	234.784	96.950
5	2005	460.904	888.99	11.38	27	491.044	235.377	97.348
5	2006	456.930	887.65	10.92	30	494.415	239.304	97.586
5	2007	443.734	885.54	11.07	30	496.090	240.310	100.035
5	2008	447.390	890.16	12.11	30	497.296	244.113	97.928
Energy factor		--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)			--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) ***continued***

California refineries		Refinery process capacity, *continued* Cat. cracking ($m^3/d \times 10^3$)	Hydrocracking ($m^3/d \times 10^3$)	1º hydrotreating ($m^3/d \times 10^3$)[a]	2º hydrotreating ($m^3/d \times 10^3$)[a]	Reforming ($m^3/d \times 10^3$)	Alkylation ($m^3/d \times 10^3$)
Calif.	2004	103.437	68.436	80.384	187.621	63.706	25.470
Calif.	2005	103.437	69.644	80.416	186.762	63.865	25.883
Calif.	2006	105.663	76.020	78.190	198.146	68.380	27.950
Calif.	2007	108.488	77.729	81.608	192.001	69.207	27.950
Calif.	2008	106.866	77.729	80.098	193.848	68.635	27.704
Calif.	2009	104.951	80.233	80.098	193.419	68.635	27.918
Energy factor		--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery process capacity, *continued* Cat. cracking ($m^3/d \times 10^3$)	Hydrocracking ($m^3/d \times 10^3$)	1º hydrotreating ($m^3/d \times 10^3$)[a]	2º hydrotreating ($m^3/d \times 10^3$)[a]	Reforming ($m^3/d \times 10^3$)	Alkylation ($m^3/d \times 10^3$)
1	1999	104.757	6.662	13.196	128.255	45.667	12.821
1	2000	107.984	6.662	13.196	124.595	44.675	13.457
1	2001	99.240	6.805	7.154	130.303	44.834	12.813
1	2002	98.989	6.024	21.311	122.137	45.276	12.923
1	2003	98.273	6.024	14.729	137.793	45.483	12.899
1	2004	98.270	6.026	14.770	135.131	46.488	12.900
1	2005	99.701	6.026	14.770	132.269	46.806	13.355
1	2006	99.701	6.153	7.043	139.933	46.806	13.347
1	2007	99.701	6.153	7.043	140.569	46.806	13.347
1	2008	99.701	6.153	7.043	140.569	46.806	13.347
2	1999	193.249	25.327	71.258	299.120	135.335	39.270
2	2000	191.890	25.327	60.988	315.480	137.696	39.588
2	2001	188.217	23.864	54.008	329.612	134.351	39.397
2	2002	186.884	24.341	71.767	314.399	133.572	38.922
2	2003	184.753	24.103	73.551	348.438	133.391	38.347
2	2004	182.678	21.908	82.141	351.570	132.471	38.067
2	2005	185.546	27.982	83.301	380.895	133.677	39.844
2	2006	185.375	30.653	79.374	390.126	133.474	39.908
2	2007	180.097	37.012	79.295	385.279	134.603	39.113
2	2008	186.759	36.519	84.398	368.902	129.722	38.707
3	1999	431.654	112.650	186.378	640.377	273.083	86.019
3	2000	434.341	115.131	191.902	658.996	277.296	85.988
3	2001	449.640	118.422	159.000	704.826	268.398	85.139
3	2002	460.097	121.379	185.875	704.153	272.336	98.062
3	2003	458.206	113.588	213.565	763.848	270.876	89.818
3	2004	461.255	118.684	222.562	823.819	275.175	105.136
3	2005	464.750	114.391	221.912	874.860	268.593	91.440
3	2006	466.316	114.471	223.013	906.027	268.569	92.526
3	2007	467.278	120.589	247.174	910.060	274.583	89.071
3	2008	473.112	118.426	229.097	940.388	270.910	91.786
5	1999	126.300	80.888	96.299	215.884	87.627	29.279
5	2000	127.174	81.190	83.468	226.261	88.486	41.806
5	2001	126.951	81.921	86.139	226.419	89.499	29.325
5	2002	127.680	81.921	94.725	218.206	88.330	29.993
5	2003	126.037	80.432	80.527	239.567	88.473	31.138
5	2004	127.166	81.378	81.513	247.651	88.953	31.185
5	2005	127.619	82.586	81.545	246.430	89.462	31.527
5	2006	130.258	88.961	79.319	257.416	94.001	33.594
5	2007	133.322	92.213	82.737	260.238	96.338	33.618
5	2008	131.700	91.243	81.227	261.749	94.733	33.371
Energy factor		--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--

Data sources given in part 1 narrative description of data

(a) Primary processing (1º) of gas oil, residua and cat. cracking feeds or secondary processing (2º) of product streams

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Refinery process capacity, *continued*						
California refineries		Pol./Dim. ($m^3/d \times 10^3$)	Aromatics ($m^3/d \times 10^3$)	Isomerization ($m^3/d \times 10^3$)	Lubes ($m^3/d \times 10^3$)	Asphalt ($m^3/d \times 10^3$)	Sulfur ($kg/d \times 10^5$)	H_2 (total) ($m^3 \times 10^8$)
Calif.	2004	1.542	0.000	24.166	2.862	6.598	37.780	131.542
Calif.	2005	1.653	0.000	24.842	2.862	6.836	38.080	132.523
Calif.	2006	1.956	0.000	26.893	3.180	6.598	41.990	142.094
Calif.	2007	1.442	0.000	25.176	3.180	6.836	39.030	145.030
Calif.	2008	1.442	0.000	24.678	3.180	6.836	42.090	145.030
Calif.	2009	1.442	0.000	24.682	3.180	9.778	44.040	145.030
Energy factor		--	--	--	--	--	--	
CO_2 emission fa		--	--	--	--	--	--	

		Refinery process capacity, *continued*						
U.S. refineries PADD	Year	Pol./Dim. ($m^3/d \times 10^3$)	Aromatics ($m^3/d \times 10^3$)	Isomerization ($m^3/d \times 10^3$)	Lubes ($m^3/d \times 10^3$)	Asphalt ($m^3/d \times 10^3$)	Sulfur ($kg/d \times 10^5$)	H_2 (total) ($m^3 \times 10^8$)
1	1999	2.836	8.611	4.473	3.685	10.334	9.210	11.783
1	2000	2.836	8.515	4.309	3.005	4.611	9.210	14.056
1	2001	2.121	8.515	5.262	3.005	4.611	8.560	11.576
1	2002	2.121	8.515	6.105	2.989	4.452	12.650	10.232
1	2003	2.121	8.515	8.685	2.989	4.452	13.010	15.090
1	2004	2.121	8.515	8.776	3.005	4.452	13.010	15.090
1	2005	2.121	8.515	8.776	3.005	4.452	13.190	15.297
1	2006	2.121	8.515	8.780	3.005	4.452	13.190	17.364
1	2007	2.121	8.515	8.780	3.005	4.452	12.850	13.333
1	2008	2.121	8.515	8.780	3.005	4.452	12.850	13.333
2	1999	2.083	9.242	27.958	2.639	34.930	44.360	44.237
2	2000	2.083	9.235	27.640	2.639	37.632	44.020	44.030
2	2001	2.083	9.235	27.568	2.639	36.170	44.250	47.751
2	2002	1.361	8.876	26.983	2.766	36.678	46.720	43.926
2	2003	1.359	8.876	28.634	2.766	37.267	48.180	40.619
2	2004	1.289	8.765	29.001	2.766	37.052	46.310	41.032
2	2005	1.278	8.383	29.079	2.687	38.141	51.400	49.611
2	2006	1.278	9.194	29.397	2.687	38.968	52.430	77.000
2	2007	1.278	6.571	29.444	2.687	31.511	46.000	77.931
2	2008	1.304	6.571	27.839	1.351	36.082	52.000	78.551
3	1999	3.100	40.811	45.229	17.862	19.304	140.920	146.456
3	2000	2.973	42.024	43.472	18.013	19.667	152.970	148.833
3	2001	2.973	42.604	42.911	17.719	18.481	152.660	155.655
3	2002	3.530	43.096	45.510	17.449	19.044	165.160	160.512
3	2003	3.545	40.724	45.720	17.926	25.692	171.340	160.512
3	2004	3.784	43.857	44.720	19.818	24.087	193.950	174.362
3	2005	3.466	43.538	43.450	23.435	19.365	191.350	172.398
3	2006	3.450	42.393	43.116	23.514	19.137	193.930	162.269
3	2007	6.458	50.263	39.229	22.818	19.375	190.130	160.822
3	2008	6.458	57.865	42.845	22.815	19.375	192.430	164.233
5	1999	2.242	0.397	20.970	4.372	11.908	41.520	126.301
5	2000	2.337	0.397	21.416	4.372	12.147	41.520	151.934
5	2001	2.337	0.445	21.416	4.372	10.779	41.520	149.247
5	2002	2.337	0.445	21.468	3.418	7.425	42.300	151.004
5	2003	2.353	0.445	27.165	3.418	9.794	43.310	148.523
5	2004	2.385	0.401	26.592	2.862	9.201	42.860	147.903
5	2005	2.496	0.358	27.274	2.862	9.396	45.200	149.557
5	2006	2.798	0.215	29.373	3.180	9.158	49.110	159.169
5	2007	2.285	0.193	32.584	3.180	9.396	45.390	162.786
5	2008	2.285	0.193	31.705	3.180	9.396	50.110	162.786
Energy factor		--	--	--	--	--	--	16.4 MJ/m^3
CO_2 emission fa		--	--	--	--	--	--	52.70

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Fuels consumed in refineries						
California refineries		H_2 (purch.) ($m^3 \times 10^8$)	Crude oil ($m^3 \times 10^4$)	LPG ($m^3 \times 10^4$)	Distillate ($m^3 \times 10^4$)	Res. fuel oil ($m^3 \times 10^4$)	Fuel gas (bl) ($m^3 \times 10^4$)	Pet. coke ($m^3 \times 10^4$)
Calif.	2004	14.418	0.000	25.803	0.000	0.000	629.035	185.480
Calif.	2005	14.470	0.000	27.129	0.000	0.000	648.594	197.475
Calif.	2006	14.056	0.000	16.132	1.244	0.000	633.147	251.324
Calif.	2007	29.146	0.000	15.421	1.001	0.000	622.581	241.058
Calif.	2008	29.146	0.000	15.982	1.939	0.000	601.661	227.776
Calif.	2009	29.146	0.000	14.781	2.507	0.000	556.490	210.530
Energy factor		16.4 MJ/m^3	38.49 GJ/m^3	25.62 GJ/m^3	38.66 GJ/m^3	41.72 GJ/m^3	39.82 GJ/m^3	39.98 GJ/m^3
CO_2 emission fa		52.70	78.53	65.76	77.18	83.14	67.73	107.74

		Fuels consumed in refineries						
U.S. refineries PADD	Year	H_2 (purch.) ($m^3 \times 10^8$)	Crude oil ($m^3 \times 10^4$)	LPG ($m^3 \times 10^4$)	Distillate ($m^3 \times 10^4$)	Res. fuel oil ($m^3 \times 10^4$)	Fuel gas (bl) ($m^3 \times 10^4$)	Pet. coke ($m^3 \times 10^4$)
1	1999		0.000	2.766	2.035	37.012	323.87	205.380
1	2000		0.000	5.008	4.166	38.904	319.90	190.928
1	2001		0.000	5.819	8.967	44.675	323.22	189.751
1	2002		0.000	4.483	7.631	29.190	339.87	188.050
1	2003		0.000	7.854	9.921	28.014	353.29	196.492
1	2004		0.000	7.870	7.409	18.013	354.19	203.774
1	2005		0.000	11.479	5.819	18.220	354.81	203.695
1	2006		0.000	5.231	0.366	14.627	337.56	175.411
1	2007		0.000	2.941	0.350	13.132	363.92	190.356
1	2008		0.000	0.827	0.461	6.344	339.09	193.933
2	1999		0.000	27.123	0.986	43.531	766.67	296.972
2	2000		0.000	14.484	0.763	34.166	773.41	293.348
2	2001		0.000	13.975	1.288	38.888	766.97	276.431
2	2002		0.000	16.439	1.081	29.747	732.93	276.892
2	2003		0.000	25.804	0.588	9.380	729.70	273.569
2	2004		0.000	17.155	0.588	3.100	792.49	253.394
2	2005		0.000	12.385	0.795	2.592	798.32	275.716
2	2006		0.000	9.015	0.715	3.275	788.34	262.361
2	2007		0.000	13.387	0.747	3.005	785.86	249.626
2	2008		0.000	12.783	0.700	3.084	777.16	238.560
3	1999		0.159	12.560	1.892	0.191	1,812.63	662.230
3	2000		0.000	13.085	2.798	0.032	1,841.63	674.535
3	2001		0.000	11.018	2.178	0.000	1,775.65	668.224
3	2002		0.000	13.450	1.336	0.000	1,811.93	668.907
3	2003		0.000	17.489	0.700	0.000	1,949.71	679.718
3	2004		0.000	5.898	1.304	0.000	1,908.64	695.951
3	2005		0.000	5.708	1.367	0.064	1,777.45	656.602
3	2006		0.000	4.404	1.765	0.016	1,988.07	724.807
3	2007		0.000	3.307	1.828	0.048	1,922.63	679.639
3	2008		0.000	8.204	1.701	0.048	1,819.56	625.981
5	1999		0.000	18.649	4.086	9.015	728.04	211.739
5	2000		0.000	34.151	3.736	11.081	742.82	223.139
5	2001		0.000	47.251	4.436	13.609	770.31	228.274
5	2002		0.000	19.587	3.307	14.341	706.94	226.398
5	2003		0.000	34.484	3.911	11.558	743.54	238.227
5	2004		0.000	24.627	3.657	11.495	739.64	244.411
5	2005		0.000	36.424	4.022	11.558	726.57	244.379
5	2006		0.000	23.339	4.054	12.242	715.43	231.327
5	2007		0.000	22.497	3.752	11.813	724.24	230.865
5	2008		0.000	23.991	4.642	11.845	689.74	196.508
Energy factor			38.49 GJ/m^3	25.62 GJ/m^3	38.66 GJ/m^3	41.72 GJ/m^3	39.82 GJ/m^3	39.98 GJ/m^3
CO_2 emission factor (kg/GJ)			78.53	65.76	77.18	83.14	67.73	107.74

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) ***continued***

		Fuels consumed in refineries *continued*					Refinery products yield	
California refineries		Other products (petajoules)	Natural gas (m^3 x 10^7)	Coal (Gg)	lectricity pur- :hased (TWh)	Steam pur- chased (Tg)	LPG (%)	Fin. motor gasoline (%)
Calif.	2004	5.112	366.244	0.000	2.972	5.268	2.2	53.4
Calif.	2005	6.461	375.964	0.000	3.107	5.674	2.0	53.3
Calif.	2006	5.583	372.101	0.000	3.257	5.766	1.7	53.9
Calif.	2007	5.583	390.180	0.000	3.113	5.728	1.7	53.7
Calif.	2008	5.583	404.019	0.000	3.304	5.559	1.7	50.6
Calif.	2009	5.583	414.216	0.000	3.059	5.846	1.6	53.5
Energy factor		Million GJ	38.27 MJ/m^3	25.80 MJ/kg	3.60 MJ/kWh	2.18 MJ/kg	--	--
CO_2 emission fa		73.20	55.98	99.58	97.22	91.63	--	--

		Fuels consumed in refineries *continued*					Refinery products yield	
U.S. refineries PADD	Year	Other products (m^3 x 10^4)	Natural gas (m^3 x 10^7)	Coal (Gg)	lectricity pur- :hased (TWh)	Steam pur- chased (Tg)	LPG (%)	Fin. motor gasoline (%)
1	1999	6.964	115.01	28.123	3.180	1.599	2.5	46.6
1	2000	6.105	125.53	27.216	3.084	1.897	2.8	45.2
1	2001	5.406	99.15	29.030	3.450	1.797	2.9	45.8
1	2002	5.851	110.86	28.123	3.282	1.865	3.0	46.7
1	2003	7.059	80.32	29.030	3.415	1.674	3.0	46.4
1	2004	2.242	91.77	26.308	3.410	2.352	2.6	46.5
1	2005	2.242	100.82	29.937	3.520	2.228	2.4	46.6
1	2006	0.859	102.58	28.123	3.576	2.593	2.6	45.8
1	2007	0.334	81.29	29.030	3.984	2.624	3.2	45.5
1	2008	0.461	78.92	28.123	4.192	2.361	3.3	44.6
2	1999	22.560	263.17	0.000	8.956	1.262	3.7	51.1
2	2000	19.047	300.38	1.814	8.949	0.890	3.7	50.4
2	2001	20.382	265.10	6.350	8.728	2.060	3.6	51.1
2	2002	19.555	272.35	0.000	8.933	2.368	3.5	52.0
2	2003	16.392	267.27	8.165	8.885	2.577	3.3	51.5
2	2004	27.855	292.54	7.258	9.486	2.863	3.3	51.6
2	2005	26.805	301.52	7.258	9.875	2.283	3.1	50.4
2	2006	31.177	324.85	2.722	10.488	3.310	4.0	49.4
2	2007	6.280	339.94	6.350	10.555	4.871	3.9	49.8
2	2008	0.286	393.30	10.886	10.804	5.000	3.5	48.5
3	1999	31.177	1,476.83	0.000	13.762	8.968	6.1	44.8
3	2000	34.405	1,475.41	0.000	14.501	11.455	6.0	44.7
3	2001	30.923	1,383.25	0.000	15.868	13.142	5.6	44.3
3	2002	21.479	1,298.76	0.000	16.145	14.670	5.8	45.4
3	2003	29.874	1,217.06	0.000	15.682	14.456	5.5	44.8
3	2004	22.544	1,118.96	0.000	17.044	14.827	5.3	44.6
3	2005	20.668	1,121.29	0.000	16.620	15.757	4.7	43.8
3	2006	31.336	1,120.29	0.000	18.612	17.690	4.8	43.5
3	2007	24.007	1,027.91	0.000	20.433	28.790	5.0	43.2
3	2008	26.996	1,078.93	0.000	20.675	28.919	5.1	41.6
5	1999	25.851	347.54	0.000	5.389	8.469	2.6	44.7
5	2000	26.185	382.68	0.000	4.809	8.268	3.1	45.7
5	2001	22.576	348.67	0.000	4.695	7.881	2.7	45.5
5	2002	22.672	387.33	0.000	4.780	7.589	2.7	47.3
5	2003	25.740	374.77	0.000	4.520	8.595	2.9	47.2
5	2004	31.305	353.35	0.000	4.871	8.732	2.6	47.3
5	2005	27.028	349.06	0.000	4.978	8.145	2.5	47.3
5	2006	34.961	357.33	0.000	4.973	8.164	2.8	47.7
5	2007	27.282	378.63	0.000	5.113	8.091	2.8	46.6
5	2008	32.227	396.29	0.000	5.125	8.064	2.8	45.6
Energy factor		38.66 GJ/m^3	38.27 MJ/m^3	25.80 MJ/kg	3.60 MJ/kWh	2.18 MJ/kg	--	--
CO_2 emission fa		73.20	55.98	99.58	187.78	91.63	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Refinery products yield *continued* Aviation gasoline (%)	Kerosene jet fuel (%)	Kerosene (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)	Oth. oils for chem FS (%)
Calif.	2004	0.2	13.7	0.0	17.3	3.7	0.0	0.5
Calif.	2005	0.1	13.6	0.0	18.8	3.4	0.0	0.5
Calif.	2006	0.1	13.3	0.0	18.7	3.4	0.0	0.5
Calif.	2007	0.1	12.9	0.0	19.2	3.9	0.0	0.3
Calif.	2008	0.1	15.7	0.0	20.6	3.2	0.0	0.1
Calif.	2009	0.0	14.3	0.0	18.7	3.1	0.0	0.4
Energy factor		--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery products yield *continued* Aviation gasoline (%)	Kerosene jet fuel (%)	Kerosene (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)	Oth. oils for chem FS (%)
1	1999	0.2	7.0	0.8	26.3	6.5	0.8	0.0
1	2000	0.2	6.3	0.8	27.9	6.8	0.8	0.0
1	2001	0.2	5.3	0.8	29.1	6.6	0.8	0.0
1	2002	0.3	5.3	0.8	28.1	5.7	0.9	0.0
1	2003	0.2	5.2	0.8	27.2	7.8	0.8	0.0
1	2004	0.4	6.1	0.7	26.6	6.9	0.8	0.0
1	2005	0.3	5.7	0.7	28.8	6.2	0.8	0.0
1	2006	0.0	5.1	0.4	29.2	7.1	1.1	0.0
1	2007	0.1	5.0	0.5	29.4	7.2	1.1	0.0
1	2008	0.0	5.7	0.6	29.6	7.1	1.1	0.0
2	1999	0.1	6.6	0.5	24.8	1.6	0.6	0.7
2	2000	0.1	6.9	0.4	25.7	1.8	0.5	0.4
2	2001	0.1	6.6	0.4	26.0	2.0	0.6	0.0
2	2002	0.1	6.7	0.3	25.4	1.8	0.6	0.0
2	2003	0.1	6.2	0.3	26.0	1.7	0.5	0.0
2	2004	0.1	6.4	0.3	25.7	1.8	0.8	0.3
2	2005	0.1	6.5	0.3	27.1	1.6	0.8	0.3
2	2006	0.1	6.2	0.3	27.3	1.7	0.9	0.2
2	2007	0.1	6.1	0.1	28.2	1.7	0.9	0.2
2	2008	0.1	6.3	0.0	30.0	1.6	0.8	0.2
3	1999	0.2	11.1	0.4	21.1	4.3	2.1	2.5
3	2000	0.1	11.1	0.4	21.9	4.6	2.2	2.3
3	2001	0.1	10.5	0.6	22.8	4.8	1.7	2.1
3	2002	0.1	10.3	0.4	22.3	3.7	2.7	1.9
3	2003	0.1	9.9	0.4	23.0	4.1	2.6	2.3
3	2004	0.1	10.0	0.5	23.5	3.9	2.8	2.4
3	2005	0.1	10.2	0.6	24.5	3.9	2.3	2.1
3	2006	0.2	9.7	0.4	25.2	3.8	1.9	2.4
3	2007	0.1	9.4	0.3	26.0	4.1	1.9	2.4
3	2008	0.1	9.6	0.0	28.4	4.0	1.5	2.3
5	1999	0.1	15.8	0.2	18.3	8.5	0.2	0.3
5	2000	0.1	16.2	0.2	18.5	6.8	0.1	0.3
5	2001	0.1	16.0	0.1	19.2	6.9	0.1	0.3
5	2002	0.1	16.0	0.1	19.0	6.2	0.1	0.3
5	2003	0.1	16.0	0.0	19.5	5.8	0.1	0.3
5	2004	0.1	16.2	0.0	19.5	6.1	0.0	0.3
5	2005	0.1	16.2	0.0	20.4	5.8	0.0	0.4
5	2006	0.1	15.3	0.0	20.3	5.8	0.0	0.4
5	2007	0.1	15.6	0.0	20.8	6.3	0.0	0.3
5	2008	0.1	17.5	0.0	21.6	5.5	0.0	0.1
Energy factor		--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Refinery products yield *continued* Special naphtha (%)	Lubricants (%)	Waxes (%)	Petroleum coke (%)	Asphalt & road oil (%)	Fuel gas (%)	Miscellaneous products (%)	Utilization of operable ref. capacity (%)
Calif.	2004	0.0	1.0	0.0	7.4	2.1	6.1	0.4	93.0
Calif.	2005	0.0	1.0	0.0	7.7	1.8	5.7	0.4	95.0
Calif.	2006	0.0	1.0	0.0	7.4	2.0	5.7	0.6	91.5
Calif.	2007	0.0	0.9	0.0	7.1	2.2	5.8	0.6	88.3
Calif.	2008	0.0	1.1	0.0	7.4	1.5	5.5	0.8	91.0
Calif.	2009	0.0	1.1	0.0	7.6	1.5	5.3	0.8	82.9
Energy factor		--	--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery products yield *continued* Special naphtha (%)	Lubricants (%)	Waxes (%)	Petroleum coke (%)	Asphalt & road oil (%)	Fuel gas (%)	Miscellaneous products (%)	Utilization of operable ref. capacity (%)
1	1999	0.1	1.0	0.0	3.1	5.4	3.7	0.1	90.9
1	2000	0.1	0.9	0.1	3.0	6.1	3.5	0.1	91.7
1	2001	0.1	0.9	0.0	3.3	6.0	3.8	0.1	87.2
1	2002	0.1	1.0	0.0	3.1	6.0	3.9	0.1	88.9
1	2003	0.1	1.0	0.0	2.9	5.7	3.8	0.1	92.7
1	2004	0.1	1.1	0.0	3.1	6.2	3.9	0.1	90.4
1	2005	0.1	1.0	0.0	2.9	5.7	3.8	0.1	93.1
1	2006	0.1	1.1	0.0	3.0	5.6	3.6	0.2	86.7
1	2007	0.0	1.0	0.0	3.2	5.0	3.9	0.2	85.6
1	2008	0.0	1.1	0.1	3.3	5.1	3.8	0.2	80.8
2	1999	0.7	0.6	0.1	4.2	5.6	3.9	0.3	93.3
2	2000	0.7	0.5	0.1	4.3	5.5	3.9	0.3	94.2
2	2001	0.6	0.4	0.1	4.3	5.1	4.0	0.3	93.9
2	2002	0.5	0.5	0.1	4.1	5.3	4.0	0.4	90.0
2	2003	0.6	0.5	0.1	4.2	5.6	4.1	0.4	91.6
2	2004	0.1	0.4	0.1	4.3	5.7	4.1	0.4	93.6
2	2005	0.2	0.4	0.1	4.5	5.7	4.1	0.5	92.9
2	2006	0.2	0.5	0.1	4.4	6.1	4.1	0.5	92.4
2	2007	0.1	0.4	0.1	4.3	5.3	4.2	0.4	90.1
2	2008	0.1	0.4	0.1	4.3	5.3	4.0	0.4	88.4
3	1999	0.8	1.7	0.2	4.8	1.7	4.1	0.4	94.7
3	2000	0.4	1.7	0.2	4.8	1.8	4.1	0.4	93.9
3	2001	0.4	1.6	0.1	5.3	1.6	4.1	0.5	94.8
3	2002	0.4	1.6	0.1	5.7	1.6	4.2	0.5	91.5
3	2003	0.4	1.5	0.1	5.7	1.6	4.4	0.5	93.6
3	2004	0.5	1.6	0.1	5.9	1.5	4.3	0.4	94.1
3	2005	0.4	1.6	0.1	6.0	1.6	4.3	0.4	88.3
3	2006	0.4	1.7	0.1	6.2	1.5	4.6	0.5	88.7
3	2007	0.5	1.7	0.1	6.0	1.3	4.3	0.5	88.7
3	2008	0.5	1.7	0.1	6.0	1.1	4.4	0.6	83.6
5	1999	0.1	1.0	0.0	6.1	2.4	5.8	0.2	87.1
5	2000	0.1	0.9	-0.1	6.3	2.4	5.6	0.3	87.5
5	2001	0.1	1.0	0.0	6.0	2.1	5.8	0.3	89.1
5	2002	0.1	0.8	0.0	6.0	2.1	5.5	0.3	90.0
5	2003	0.1	0.8	0.0	6.2	1.9	5.6	0.3	91.3
5	2004	0.0	0.7	0.0	6.1	1.9	5.4	0.3	90.4
5	2005	0.0	0.7	0.0	6.2	1.7	5.1	0.3	91.7
5	2006	0.1	0.7	0.0	6.0	1.8	5.2	0.4	90.5
5	2007	0.0	0.6	0.0	5.8	1.8	5.4	0.4	87.6
5	2008	0.0	0.8	0.0	6.1	1.4	5.1	0.5	88.1
Energy factor		--	--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Energy consumed/vol. crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels									
California		3rd-party H_2 prod.		Crude oil consmd.		LPG consumed		Distillate consmd.		Res. Fuel Oil cons.	
refineries		(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
Calif.	2004	0.204	10.77	0.000	0.00	0.063	4.18	0.000	0.00	0.000	0.00
Calif.	2005	0.199	10.50	0.000	0.00	0.065	4.26	0.000	0.00	0.000	0.00
Calif.	2006	0.199	10.49	0.000	0.00	0.040	2.61	0.005	0.36	0.000	0.00
Calif.	2007	0.423	22.31	0.000	0.00	0.039	2.56	0.004	0.29	0.000	0.00
Calif.	2008	0.413	21.75	0.000	0.00	0.039	2.58	0.007	0.55	0.000	0.00
Calif.	2009	0.447	23.57	0.000	0.00	0.039	2.59	0.010	0.78	0.000	0.00
Energy factor		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3	
CO_2 emission fa		--	52.70	--	78.53	--	65.76	--	77.18	--	83.14

		Energy consumed/vol. crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels									
U.S. refineries		Hydrogen prod.		Crude oil consmd.		LPG consumed		Distillate consmd.		Res. Fuel Oil cons.	
PADD	Year	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
1	1999	0.195	10.28	0.000	0.00	0.008	0.52	0.009	0.68	0.173	14.39
1	2000	0.230	12.10	0.000	0.00	0.014	0.93	0.018	1.38	0.180	14.94
1	2001	0.199	10.48	0.000	0.00	0.017	1.14	0.040	3.11	0.217	18.03
1	2002	0.171	8.99	0.000	0.00	0.013	0.85	0.033	2.57	0.138	11.44
1	2003	0.242	12.77	0.000	0.00	0.022	1.44	0.042	3.22	0.127	10.57
1	2004	0.245	12.88	0.000	0.00	0.022	1.46	0.031	2.43	0.083	6.86
1	2005	0.243	12.82	0.000	0.00	0.032	2.08	0.024	1.87	0.082	6.81
1	2006	0.297	15.66	0.000	0.00	0.016	1.02	0.002	0.13	0.071	5.88
1	2007	0.230	12.13	0.000	0.00	0.009	0.58	0.002	0.12	0.064	5.33
1	2008	0.244	12.85	0.000	0.00	0.003	0.17	0.002	0.17	0.033	2.73
2	1999	0.334	17.58	0.000	0.00	0.036	2.33	0.002	0.15	0.093	7.71
2	2000	0.328	17.31	0.000	0.00	0.019	1.23	0.002	0.12	0.072	5.99
2	2001	0.367	19.34	0.000	0.00	0.019	1.23	0.003	0.20	0.085	7.02
2	2002	0.347	18.30	0.000	0.00	0.023	1.48	0.002	0.17	0.067	5.53
2	2003	0.321	16.89	0.000	0.00	0.035	2.32	0.001	0.09	0.021	1.74
2	2004	0.316	16.66	0.000	0.00	0.023	1.51	0.001	0.09	0.007	0.56
2	2005	0.381	20.07	0.000	0.00	0.017	1.09	0.002	0.12	0.006	0.47
2	2006	0.592	31.19	0.000	0.00	0.012	0.79	0.001	0.11	0.007	0.59
2	2007	0.612	32.26	0.000	0.00	0.018	1.20	0.002	0.12	0.007	0.55
2	2008	0.616	32.46	0.000	0.00	0.017	1.14	0.001	0.11	0.007	0.57
3	1999	0.530	27.94	0.000	0.01	0.008	0.52	0.002	0.14	0.000	0.02
3	2000	0.533	28.06	0.000	0.00	0.008	0.53	0.003	0.20	0.000	0.00
3	2001	0.545	28.70	0.000	0.00	0.007	0.44	0.002	0.15	0.000	0.00
3	2002	0.576	30.33	0.000	0.00	0.008	0.55	0.001	0.10	0.000	0.00
3	2003	0.560	29.49	0.000	0.00	0.011	0.70	0.001	0.05	0.000	0.00
3	2004	0.592	31.19	0.000	0.00	0.004	0.23	0.001	0.09	0.000	0.00
3	2005	0.609	32.08	0.000	0.00	0.004	0.23	0.001	0.10	0.000	0.01
3	2006	0.560	29.49	0.000	0.00	0.003	0.17	0.002	0.12	0.000	0.00
3	2007	0.553	29.12	0.000	0.00	0.002	0.13	0.002	0.13	0.000	0.00
3	2008	0.594	31.28	0.000	0.00	0.005	0.34	0.002	0.12	0.000	0.00
5	1999	1.217	64.13	0.000	0.00	0.031	2.05	0.010	0.80	0.025	2.04
5	2000	1.426	75.15	0.000	0.00	0.056	3.66	0.009	0.71	0.029	2.44
5	2001	1.364	71.86	0.000	0.00	0.075	4.93	0.011	0.82	0.035	2.92
5	2002	1.363	71.85	0.000	0.00	0.031	2.02	0.008	0.60	0.037	3.04
5	2003	1.315	69.32	0.000	0.00	0.053	3.49	0.009	0.70	0.029	2.41
5	2004	1.315	69.29	0.000	0.00	0.038	2.50	0.009	0.66	0.029	2.40
5	2005	1.312	69.15	0.000	0.00	0.056	3.65	0.009	0.71	0.029	2.38
5	2006	1.409	74.24	0.000	0.00	0.036	2.36	0.009	0.73	0.031	2.55
5	2007	1.484	78.18	0.000	0.00	0.036	2.34	0.009	0.69	0.030	2.53
5	2008	1.471	77.54	0.000	0.00	0.038	2.48	0.011	0.85	0.030	2.52
Energy factor		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3	
CO_2 emission fa		--	52.70	--	78.53	--	65.76	--	77.18	--	83.14

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Energy consumed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels *continued*									
California		Fuel Gas (bl)		Petroleum coke		Other products		Natural Gas		Coal consumed	
refineries		(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
Calif.	2004	2.406	162.95	0.712	76.74	0.049	3.59	1.346	75.36	0.000	0.00
Calif.	2005	2.409	163.18	0.736	79.35	0.060	4.41	1.342	75.13	0.000	0.00
Calif.	2006	2.419	163.85	0.964	103.88	0.054	3.92	1.366	76.49	0.000	0.00
Calif.	2007	2.440	165.23	0.948	102.18	0.055	4.02	1.469	82.26	0.000	0.00
Calif.	2008	2.298	155.64	0.873	94.11	0.054	3.92	1.483	83.02	0.000	0.00
Calif.	2009	2.303	156.01	0.875	94.26	0.058	4.25	1.648	92.24	0.000	0.00
Energy factor		39.82 GJ/m^3		39.98 GJ/m^3		38.66 GJ/m^3		38.27 MJ/m^3		25.80 MJ/kg	
CO_2 emission fa		--	67.73	--	107.74	--	73.20	--	55.98	--	99.58

		Energy consumed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels *continued*									
U.S. refineries		Fuel Gas (bl)		Petroleum coke		Other products		Natural Gas		Coal consumed	
PADD	Year	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
1	1999	1.446	97.93	0.921	99.19	0.030	2.21	0.494	27.63	0.008	0.81
1	2000	1.410	95.49	0.845	91.02	0.026	1.91	0.532	29.76	0.008	0.77
1	2001	1.498	101.43	0.883	95.10	0.024	1.78	0.442	24.72	0.009	0.87
1	2002	1.529	103.58	0.850	91.53	0.026	1.87	0.479	26.84	0.008	0.82
1	2003	1.530	103.66	0.855	92.08	0.030	2.17	0.334	18.72	0.008	0.81
1	2004	1.548	104.85	0.894	96.34	0.010	0.70	0.386	21.58	0.008	0.74
1	2005	1.523	103.13	0.878	94.56	0.009	0.68	0.416	23.28	0.008	0.83
1	2006	1.559	105.58	0.813	87.62	0.004	0.28	0.455	25.48	0.008	0.84
1	2007	1.695	114.82	0.890	95.92	0.002	0.11	0.364	20.37	0.009	0.87
1	2008	1.673	113.30	0.961	103.49	0.002	0.16	0.374	20.95	0.009	0.90
2	1999	1.560	105.64	0.607	65.35	0.045	3.26	0.515	28.80	0.000	0.00
2	2000	1.556	105.41	0.593	63.85	0.037	2.72	0.581	32.52	0.000	0.02
2	2001	1.591	107.72	0.576	62.01	0.041	3.00	0.528	29.58	0.001	0.09
2	2002	1.563	105.85	0.593	63.87	0.041	2.96	0.558	31.24	0.000	0.00
2	2003	1.553	105.19	0.585	62.99	0.034	2.48	0.547	30.60	0.001	0.11
2	2004	1.647	111.58	0.529	56.98	0.056	4.12	0.584	32.72	0.001	0.10
2	2005	1.653	111.96	0.573	61.76	0.054	3.94	0.600	33.59	0.001	0.10
2	2006	1.635	110.72	0.546	58.85	0.063	4.59	0.647	36.24	0.000	0.04
2	2007	1.665	112.80	0.531	57.22	0.013	0.95	0.692	38.76	0.001	0.09
2	2008	1.644	111.34	0.507	54.59	0.001	0.04	0.800	44.76	0.002	0.15
3	1999	1.771	119.92	0.650	69.97	0.030	2.16	1.386	77.61	0.000	0.00
3	2000	1.778	120.40	0.654	70.43	0.032	2.36	1.369	76.62	0.000	0.00
3	2001	1.676	113.50	0.633	68.22	0.028	2.07	1.255	70.23	0.000	0.00
3	2002	1.753	118.71	0.650	69.99	0.020	1.48	1.207	67.59	0.000	0.00
3	2003	1.834	124.18	0.642	69.14	0.027	2.00	1.100	61.57	0.000	0.00
3	2004	1.748	118.37	0.640	68.93	0.020	1.47	0.985	55.12	0.000	0.00
3	2005	1.693	114.67	0.628	67.65	0.019	1.40	1.027	57.46	0.000	0.00
3	2006	1.850	125.28	0.677	72.95	0.028	2.07	1.002	56.08	0.000	0.00
3	2007	1.782	120.72	0.633	68.15	0.022	1.58	0.916	51.27	0.000	0.00
3	2008	1.774	120.17	0.613	66.03	0.026	1.87	1.011	56.60	0.000	0.00
5	1999	1.892	128.17	0.553	59.53	0.065	4.78	0.868	48.60	0.000	0.00
5	2000	1.881	127.39	0.567	61.12	0.064	4.71	0.931	52.13	0.000	0.00
5	2001	1.899	128.60	0.565	60.86	0.054	3.95	0.826	46.24	0.000	0.00
5	2002	1.722	116.63	0.554	59.66	0.054	3.92	0.907	50.76	0.000	0.00
5	2003	1.777	120.32	0.572	61.57	0.060	4.37	0.861	48.17	0.000	0.00
5	2004	1.774	120.15	0.589	63.41	0.073	5.34	0.815	45.60	0.000	0.00
5	2005	1.720	116.48	0.581	62.57	0.062	4.55	0.794	44.45	0.000	0.00
5	2006	1.708	115.69	0.555	59.75	0.081	5.93	0.820	45.90	0.000	0.00
5	2007	1.781	120.60	0.570	61.40	0.065	4.77	0.895	50.08	0.000	0.00
5	2008	1.682	113.92	0.481	51.83	0.076	5.58	0.929	51.99	0.000	0.00
Energy factor		39.82 GJ/m^3		39.98 GJ/m^3		38.66 GJ/m^3		38.27 MJ/m^3		25.80 MJ/kg	
CO_2 emission fa		--	67.73	--	107.74	--	73.20	--	55.98	--	99.58

Data sources given in part 1 narrative

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Energy consumed & CO_2 emitted/vol. crude feed for refinery fuels *continued* — Electricity purchased (GJ/m³)	Electricity purchased (kg/m³)	Steam purchased (GJ/m³)	Steam purchased (kg/m³)	Refinery energy intensity *(EI)* (GJ/m³)	Fuel mix emit intensity (CO_2) (kg/GJ)	Refinery emission intensity (CO_2) (kg/m³)
Calif.	2004	0.103	9.99	0.110	10.11	4.994	70.82	353.7
Calif.	2005	0.104	10.14	0.115	10.57	5.032	71.06	357.5
Calif.	2006	0.113	10.94	0.121	11.05	5.280	72.65	383.6
Calif.	2007	0.110	10.72	0.123	11.26	5.611	71.43	400.8
Calif.	2008	0.114	11.09	0.116	10.65	5.397	71.02	383.3
Calif.	2009	0.114	11.13	0.132	12.14	5.628	70.54	397.0
Energy factor		3.60 MJ/kWh		2.18 MJ/kg		--	--	--
CO_2 emission fa		--	97.22	--	91.63	--	--	--

U.S. refineries PADD	Year	Energy & CO_2/vol. crude for fuels *continued* — Electricity purchased (GJ/m³)	Electricity purchased (kg/m³)	Steam purchased (GJ/m³)	Steam purchased (kg/m³)	Refinery energy intensity *(EI)* (GJ/m³)	Fuel mix emit intensity (CO_2) (kg/GJ)	Refinery emission intensity (CO_2) (kg/m³)
1	1999	0.128	24.10	0.039	3.58	3.451	81.53	281.3
1	2000	0.123	23.07	0.046	4.19	3.430	80.34	275.6
1	2001	0.145	27.14	0.046	4.18	3.518	81.85	288.0
1	2002	0.134	25.07	0.046	4.21	3.426	81.08	277.8
1	2003	0.134	25.11	0.040	3.64	3.364	81.51	274.2
1	2004	0.135	25.30	0.056	5.16	3.416	81.46	278.3
1	2005	0.137	25.64	0.052	4.80	3.404	81.23	276.5
1	2006	0.149	28.03	0.066	6.01	3.440	80.40	276.5
1	2007	0.168	31.51	0.067	6.13	3.499	82.28	287.9
1	2008	0.187	35.11	0.064	5.84	3.551	83.26	295.7
2	1999	0.165	30.93	0.014	1.29	3.368	78.11	263.1
2	2000	0.163	30.57	0.010	0.90	3.361	77.56	260.6
2	2001	0.164	30.73	0.023	2.14	3.396	77.46	263.1
2	2002	0.172	32.34	0.028	2.53	3.393	77.90	264.3
2	2003	0.171	32.10	0.030	2.75	3.298	78.00	257.3
2	2004	0.178	33.48	0.033	2.99	3.376	77.25	260.8
2	2005	0.185	34.71	0.026	2.37	3.496	77.27	270.2
2	2006	0.197	36.92	0.038	3.44	3.738	75.84	283.5
2	2007	0.202	37.97	0.057	5.18	3.800	75.55	287.1
2	2008	0.207	38.80	0.058	5.31	3.858	74.97	289.3
3	1999	0.122	22.82	0.048	4.39	4.546	71.61	325.5
3	2000	0.127	23.76	0.061	5.55	4.563	71.87	327.9
3	2001	0.135	25.42	0.068	6.22	4.348	72.43	315.0
3	2002	0.141	26.51	0.078	7.12	4.434	72.71	322.4
3	2003	0.133	25.04	0.074	6.82	4.381	72.81	319.0
3	2004	0.141	26.49	0.074	6.81	4.204	73.43	308.7
3	2005	0.143	26.88	0.082	7.53	4.205	73.24	308.0
3	2006	0.157	29.40	0.090	8.26	4.367	74.15	323.8
3	2007	0.171	32.16	0.146	13.39	4.226	74.93	316.7
3	2008	0.182	34.23	0.154	14.15	4.361	74.48	324.8
5	1999	0.127	23.78	0.121	11.04	4.908	70.27	344.9
5	2000	0.110	20.67	0.115	10.50	5.189	69.09	358.5
5	2001	0.105	19.65	0.106	9.74	5.039	69.38	349.6
5	2002	0.105	19.77	0.101	9.27	4.881	69.15	337.5
5	2003	0.098	18.33	0.112	10.30	4.885	69.40	339.0
5	2004	0.106	19.83	0.115	10.51	4.861	69.89	339.7
5	2005	0.107	20.00	0.106	9.67	4.774	69.88	333.6
5	2006	0.107	20.16	0.107	9.78	4.862	69.32	337.1
5	2007	0.114	21.34	0.109	9.98	5.091	69.12	351.9
5	2008	0.113	21.22	0.108	9.86	4.939	68.39	337.8
Energy factor		3.60 MJ/kWh		2.18 MJ/kg		--	--	--
CO_2 emission fa		--	187.78	--	91.63	--	--	--

Data sources given in part 1 narrative description of data

Table 2-2. Third-party refinery hydrogen supply data evaluation

Data are totals for California refineries	2008	2009
Hydrogen production capacity data[a]		
Third-party capacity serving refineries ($m^3 \bullet 10^8$)	29.15	29.15
Production at typical (90%) capacity utilization		
Third-party at 90% of capacity ($m^3 \bullet 10^8$)	26.23	26.23
Estimated energy to make hydrogen at 90% capacity[b]		
Third-party at 90% capacity (GJ)	43,019,496	43,019,496
Estimated CO_2 emissions from H_2 at 90% capacity[c]		
Emissions at 90% third-party capacity (tonnes)	2,267,127	2,267,127
Emissions reported (Mandatory GHG Reporting)[d]		
Third-party emissions (tonnes)	2,224,778	2,193,684
Difference from third-party estimate (%)	-2%	-3%
Energy calculated from reported emission (GJ)	42,215,901	41,625,882
Difference from third-party estimate (%)	-2%	-3%

[a] From *Oil & Gas Journal* Worldwide Refining surveys *(6).*

[b] Energy based on 16.4 MJ/m^3 energy factor for natural gas-fed steam reforming *(1).*

[c] Emissions based on a 52.7 kg/GJ factor for natural gas-fed steam reforming *(1).*

[d] Facilityy-reported Mandatory GHG Reporting Rule emissions *(2).*

Table 2-3. Density and sulfur content of average California crude feeds, summary of calculation

Year	Feed source	Feed volume (m^3/year)[a]	Specific gravity	Sulfur (% wt.)	Feed mass (tonnes)	Feed sulfur (tonnes)	Feed *d* (kg/m^3)	Feed *S* (kg/m^3)
2009	California[b]	38,007,186	0.9274	1.12	35,249,004	394,436	927.430	10.378
2009	Alaska (TAPS)[c]	14,491,215	0.8714	1.11	12,627,065	140,160	871.360	9.672
2009	Foreign imports[d]	43,703,065	0.8887	1.52	38,838,914	590,740	888.700	13.517
2009	**Refinery input**	96,202,420	--	--	86,714,984	1,125,337	**901.380**	**11.698**
2008	California[b]	39,745,712	0.9273	1.16	36,855,722	427,895	927.288	10.766
2008	Alaska (TAPS)[c]	13,985,477	0.8714	1.11	12,186,385	135,269	871.360	9.672
2008	Foreign imports[d]	50,526,005	0.8906	1.73	44,997,449	776,206	890.58	15.36
2008	**Refinery input**	104,257,194	--	--	94,039,556	1,339,370	**902.00**	**12.85**
2007	California[b]	39,976,562	0.9269	1.10	37,055,075	407,606	926.92	10.20
2007	Alaska (TAPS)[c]	16,041,819	0.8714	1.11	13,978,199	155,158	871.36	9.67
2007	Foreign imports[d]	45,604,553	0.8861	1.60	40,411,563	645,777	886.13	14.16
2007	**Refinery input**	101,622,933	--	--	91,444,836	1,208,541	**899.84**	**11.89**
2006	California[b]	40,461,950	0.9270	1.10	37,506,204	410,693	926.95	10.15
2006	Alaska (TAPS)[c]	16,802,414	0.8714	1.11	14,640,951	162,515	871.36	9.67
2006	Foreign imports[d]	46,949,904	0.8860	1.56	41,599,493	648,952	886.04	13.82
2006	**Refinery input**	104,214,267	--	--	93,746,648	1,222,160	**899.56**	**11.73**
2005	California[b]	42,298,889	0.9277	1.10	39,240,679	431,255	927.70	10.20
2005	Alaska (TAPS)[c]	21,607,328	0.8714	1.11	18,827,761	208,988	871.36	9.67
2005	Foreign imports[d]	43,295,104	0.8886	1.63	38,472,895	626,723	888.62	14.48
2005	**Refinery input**	107,201,321	--	--	96,541,336	1,266,967	**900.56**	**11.82**
2004	California[b]	43,625,479	0.9279	1.18	40,481,871	476,472	927.94	10.92
2004	Alaska (TAPS)[c]	22,570,950	0.8714	1.11	19,667,423	218,308	871.36	9.67
2004	Foreign imports[d]	37,915,927	0.8828	1.49	33,471,422	498,055	882.78	13.14
2004	**Refinery input**	104,112,356	--	--	93,620,716	1,192,835	**899.23**	**11.46**

[a] Feed volumes from California Energy Commission *(5).*

[b] Weighted average density and sulfur content of California-produced crude from data in Table 2-4.

[c] Density and sulfur content, Alaska North Slope blend, TAPS terminus at Valdez, 2002 *(16).*

[d] Weighted average density and sulfur content of all foreign crude imports processed in California *(14).*

Table 2-4. California-producted crude data by field, area, and pool, formation or zone

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Aliso Canyon	Field	Field total					23.084	23.396	21.997	20.707	21.005	23.987
Aliso Canyon	Field	Not matched to pool/*OQ*	0.917	*b*	0.80	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Aliso Canyon		Aliso	0.969	*c*	0.94	*c*	1.512	1.297	1.036	0.307	0.690	0.481
Aliso Canyon		Aliso, West	0.993	*c*	0.80	*b*	0.604	0.490	0.454	0.378	0.201	0.166
Aliso Canyon		Porter-Del Aliso A-36	0.913	*c*	0.80	*b*	5.749	5.060	4.881	5.433	8.133	8.474
Aliso Canyon		Porter, West	0.911	*c*	0.80	*b*	0.000	0.000	0.000	0.000	0.010	0.028
Aliso Canyon		Mission-Adrian	0.882	*c*	0.80	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Aliso Canyon		Monterey	0.917	*b*	0.80	*b*	0.000	0.000	0.000	0.000	0.000	0.018
Aliso Canyon		Sesnon-Frew A/	0.840	*c*	0.80	*b*	15.219	16.550	15.626	14.589	11.970	14.820
Aliso Canyon		Faulted Sesnon	0.922	*c*	0.80	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Ant Hill	Field	Field total					12.225	12.145	15.664	17.945	12.714	9.251
Ant Hill	Field	Not matched to pool/*OQ*	0.898	*b*	0.48	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Ant Hill		Olcese	0.968	*b*	0.68	*b*	12.225	12.145	15.664	17.945	12.714	9.251
Ant Hill		Jewett	0.828	*b*	0.28	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Field	Field total					37.514	31.996	27.777	25.870	26.880	24.872
Antelope Hills	Field	Not matched to pool/*OQ*	0.946	*c*	0.69	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Hopkins Area	Phacoides	0.871	*c*	0.69	*c*	0.363	0.339	0.251	0.222	0.254	0.210
Antelope Hills	Hopkins Area	Eocene	0.953	*c*	0.69	*c*	0.560	0.560	0.486	0.469	0.543	0.382
Antelope Hills	Williams Area	No breakdown by pool	0.957	*c*	0.69	*c*	0.000	0.000	0.000	0.000	0.006	1.967
Antelope Hills	Williams Area	Gas Zone	0.946	*c*	0.69	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Williams Area	Upper	0.986	*c*	0.69	*c*	1.311	2.208	0.951	0.695	1.550	0.676
Antelope Hills	Williams Area	East Block-Button Bed	0.953	*c*	0.69	*c*	12.877	7.884	6.092	0.695	5.371	4.259
Antelope Hills	Williams Area	East Block-Agua	0.947	*c*	0.69	*c*	4.322	2.483	3.335	6.243	4.232	4.220
Antelope Hills	Williams Area	W. Blk-Button Bed & Agua	0.947	*c*	0.69	*c*	6.421	5.543	4.724	3.582	6.344	5.548
Antelope Hills	Williams Area	Point of Rocks	0.953	*c*	0.69	*c*	11.659	12.979	11.938	8.977	8.580	7.627
Antelope Hills	Nepple Area Gas	All	0.946	*c*	0.69	*c*	0.000	0.000	0.000	0.000	0.000	3.602
Antelope Hills, North	Field	Field total					12.912	13.516	13.064	12.349	22.827	35.157
Antelope Hills, North	Field	Not matched to pool/*OQ*	0.953	*d*			0.000	0.000	0.000	0.000	0.005	0.386
Antelope Hills, North		Miocene-Eocene	0.974	*c*			12.912	13.516	13.064	11.733	11.885	14.800
Antelope Hills, North		Point of Rocks	0.959	*c*			0.000	0.000	0.000	0.616	10.937	23.572
Arroyo Grande	Field	Field total					97.925	92.775	92.838	87.130	75.491	71.809
Arroyo Grande	Field	Not matched to pool/*OQ*	0.969	*c*	1.30	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Arroyo Grande	Oak Park Area	Martin-Elberta	0.966	*c*	1.30	*b*	0.069	0.003	0.016	0.000	0.000	0.394
Arroyo Grande	Tiber Area	Dollie	0.973	*c*	1.30	*b*	97.856	92.772	92.822	87.130	75.491	71.415
Asphalto	Field	Field total					21.839	21.726	19.621	31.842	41.838	38.404
Asphalto	Field	Not matched to pool/*OQ*	0.845	*c*	0.42	*b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Asphalto		Etchegoin	0.973 *c*	0.42 *b*	0.000	0.000	0.000	1.120	0.866	0.703
Asphalto		Olig	0.789 *c*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Asphalto		Antelope Shale	0.846 *c*	0.42 *b*	2.978	2.804	0.363	1.349	3.153	4.903
Asphalto		Stevens	0.849 *b*	0.42 *b*	17.510	17.959	18.539	28.593	37.315	31.671
Asphalto		1st Carneros	0.805 *c*	0.42 *b*	1.352	0.962	0.719	0.780	0.504	1.019
Asphalto		Carneros	0.805 *c*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bandini	Field	Field total			2.647	3.271	3.476	3.432	3.123	1.571
Bandini	Field	Not matched to pool/*OQ*	0.841 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Bandini		Pliocene	0.837 *c*		2.647	3.271	3.476	3.432	3.123	1.571
Bandini		Miocene	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Barham Ranch	Field	Field total			17.622	16.373	18.360	15.201	14.908	13.026
Barham Ranch	Field	Not matched to pool/*OQ*	0.918 *c*	1.30 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Barham Ranch	La Laguna	Monterey	0.868 *c*	1.30 *c*	17.065	15.520	14.194	11.915	11.872	9.833
Barham Ranch	Old Area		0.968 *c*	1.30 *c*	0.558	0.853	4.166	3.285	3.037	3.193
Barsdale	Field	Field total			14.820	11.247	8.792	9.916	8.542	7.176
Barsdale	Field	Not matched to pool/*OQ*	0.881 *c*	0.83 *b*	14.820	11.247	8.792	9.916	6.032	5.237
Barsdale		Deep	0.857 *c*	0.83 *b*	0.000	0.000	0.000	0.000	2.510	1.939
Beer Nose	Field	Field total			0.949	0.937	0.905	0.569	0.306	0.433
Beer Nose	Field	Not matched to pool/*OQ*	0.871 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Beer Nose		Bloemer	0.871 *c*		0.949	0.937	0.905	0.569	0.306	0.433
Belgian Anticline	Field	Field total			11.077	8.739	9.653	9.303	8.523	8.563
Belgian Anticline	Field	Not matched to pool/*OQ*	0.850 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belgian Anticline	Main Area	No breakdown by pool	0.838 *c*	0.41 *b*	9.176	7.123	7.185	8.166	7.535	6.893
Belgian Anticline	Main Area	Oceanic	0.850 *b*	0.59 *b*	0.000	0.000	0.000	0.206	0.000	0.000
Belgian Anticline	Main Area	Point of Rocks	0.800 *c*	0.41 *c*	0.385	0.449	0.589	0.931	0.247	0.328
Belgian Anticline	Northwest Area	No breakdown by pool	0.885 *c*	0.59 *b*	1.516	1.167	1.880	0.931	0.741	1.342
Belgian Anticline	Northwest Area	Miocene	0.860 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belgian Anticline	Northwest Area	Eocene	0.846 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bellevue	Field	Field total			6.161	5.617	5.639	6.320	5.521	5.073
Bellevue	Field	Not matched to pool/*OQ*	0.850 *c*	0.36 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bellevue	Main Area	Stevens	0.855 *c*	0.36 *b*	5.333	4.890	4.804	5.515	4.782	4.341
Bellevue	South Area	Stevens	0.845 *c*	0.36 *b*	0.828	0.727	0.835	0.805	0.738	0.731
Bellevue, West	Field	Field total			4.724	3.766	4.310	3.823	4.897	4.620
Bellevue, West	Field	Not matched to pool/*OQ*	0.868 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Bellevue, West		Stevens	0.868 *c*		4.724	3.766	4.310	3.823	4.897	4.620
Belmont Offshore	Field	Field total			51.407	66.657	108.201	12.418	114.889	106.080

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Belmont Offshore	Field	Not matched to pool/*OQ*	0.883	*b*	0.90	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Old Area	Upper	0.926	*c*	0.90	*b*	0.000	22.183	53.991	57.897	59.375	56.347
Belmont Offshore	Old Area	Intermediate	0.899	*c*	0.90	*b*	0.000	0.000	0.000	4.088	11.400	6.554
Belmont Offshore	Old Area	Lower	0.899	*c*	0.90	*c*	5.408	5.008	15.576	25.943	18.030	26.106
Belmont Offshore	Old Area	237	0.883	*b*	0.90	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Old Area	Schist	0.883	*b*	0.90	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Surfside Area		0.897	*c*	0.14	*c*	45.999	39.465	38.634	36.734	26.084	17.073
Belridge, North	Field	Field total					609.344	591.421	540.598	525.997	563.581	519.432
Belridge, North	Field	Not matched to pool/*OQ*	0.854	*b,c*	0.66	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Belridge, North		Tulare	0.972	*b*	1.14	*b*	29.653	21.937	150.161	18.346	23.115	19.580
Belridge, North		Diatomite	0.890	*c*	1.14	*b*	559.721	548.835	502.891	492.418	525.835	486.952
Belridge, North		Temblor	0.825	*c*	0.69	*c*	2.260	1.186	2.557	2.211	2.373	1.781
Belridge, North		R Sand	0.771	*c*	0.17	*c*	1.055	1.179	5.091	3.607	2.522	2.311
Belridge, North		Belridge 64	0.828	*c*	0.17	*c*	16.655	18.284	15.037	9.414	9.735	8.809
Belridge, North		Y Sand	0.835	*c*	0.65	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Belridge, South	Field	Field total					6,301.301	5,907.403	5,645.857	5,360.766	5,159.343	4,652.846
Belridge, South	Field	Not matched to pool/*OQ*	0.906	*b,c*	0.70	*b,c*	0.000	0.000	0.000	0.000	0.644	0.671
Belridge, South		Tulare	0.966	*b*	0.23	*b*	2,504.036	2,288.377	2,155.501	2,139.089	2,009.493	1,785.617
Belridge, South		Diatomite	0.890	*c*	0.86	*b*	3,768.569	3,593.228	3,466.721	3,197.425	3,129.365	2,849.268
Belridge, South		Diatomite-Antelope Shale	0.886	*c*	0.86	*b*	2.074	2.567	3.163	7.187	6.114	6.784
Belridge, South		Antelope Shale	0.882	*c*	0.86	*b*	26.622	23.231	20.472	17.065	13.728	10.664
Beta Offshore	Field	Field total					135.378	144.755	132.025	144.490	173.583	231.143
Beta Offshore	Field	Not matched to pool/*OQ*	0.959	*d*	3.80	*c*	135.378	144.755	132.025	144.490	173.583	231.143
Beverly Hills	Field	Field total					175.960	178.745	173.359	153.548	140.515	137.987
Beverly Hills	Field	Not matched to pool/*OQ*	0.869	*c*	2.41	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Beverly Hills	East Area	Pliocene	0.850	*c*	2.30	*c*	11.382	13.489	11.618	10.314	10.037	9.221
Beverly Hills	East Area	Miocene	0.855	*c*	2.45	*b*	131.046	3.572	125.216	109.708	99.962	98.761
Beverly Hills	West Area	Pliocene	0.944	*c*	2.45	*b*	0.522	0.290	0.338	0.750	0.675	0.726
Beverly Hills	West Area	Miocene	0.827	*c*	2.45	*b*	33.010	34.205	36.188	32.775	29.841	29.280
Big Mountain	Field	Field total					5.287	3.486	4.818	5.460	5.778	5.622
Big Mountain	Field	Not matched to pool/*OQ*	0.901	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Big Mountain		Sespe	0.932	*c*			5.287	3.486	4.818	5.460	5.778	5.622
Big Mountain		Eocene	0.876	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Bitterwater	Field	Field total					0.364	0.346	0.356	0.339	0.311	0.297
Bitterwater	Field	Not matched to pool/*OQ*	0.896	*c*			0.364	0.346	0.356	0.339	0.311	0.297
Blackwells Corner	Field	Field total					1.423	1.162	1.290	3.022	2.016	1.661

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Blackwells Corner	Field	Not matched to pool/*OQ*	0.973	*b*			1.423	1.162	1.290	3.022	2.016	1.661
Bowerbank	Field	Field total					0.893	0.033	0.000	0.000	0.000	0.000
Bowerbank	Field	Not matched to pool/*OQ*	0.865	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Bowerbank		Gas Zone	0.865	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Bowerbank		Stevens	0.865	*c*			0.893	0.033	0.000	0.000	0.000	0.000
Brea-Olinda	Field	Field total					200.487	196.035	196.141	187.882	179.099	190.006
Brea-Olinda	Field	Not matched to pool/*OQ*	0.917	*c*	1.43	*b*	200.487	196.035	196.141	187.882	179.099	190.006
Brentwood	Field	Field total					0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Field	Not matched to pool/*OQ*	0.823	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Prewett	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive Block IA	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive Block III	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Second Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Third Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	First Massive	0.797	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	Second Massive	0.835	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	Third Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Buena Vista	Field	Field total					122.660	114.225	113.420	118.835	153.799	169.786
Buena Vista	Field	Not matched to pool/*OQ*	0.886	*b,c*	0.56	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Buena Vista	Buena Vista Front		0.917	*c*	0.59	*b*	12.847	10.922	10.969	9.058	9.846	8.646
Buena Vista	Buena Vista Hills	No breakdown by pool	0.894	*b*	0.59	*b*	0.000	0.000	0.000	0.000	0.015	1.762
Buena Vista	Buena Vista Hills	Gas Zone	0.873	*b*	0.59	*b*	0.256	0.323	0.126	0.066	0.069	0.184
Buena Vista	Buena Vista Hills	Gas Zone-Upper	0.873	*b*	0.59	*b*	0.738	0.721	0.585	0.416	0.264	0.226
Buena Vista	Buena Vista Hills	Upper Undifferentiated	0.893	*c*	0.59	*b*	59.805	54.252	53.708	59.124	71.357	88.160
Buena Vista	Buena Vista Hills	Sub-Scalez & Mulinia	0.893	*c*	0.59	*b*	0.426	0.497	0.302	0.605	0.286	0.481
Buena Vista	Buena Vista Hills	27B Undifferentiated	0.888	*c*	0.59	*b*	1.049	1.415	1.577	1.467	2.702	4.156
Buena Vista	Buena Vista Hills	Reef Ridge	0.876	*c*	0.50	*b*	0.655	0.474	0.662	1.360	1.748	1.253
Buena Vista	Buena Vista Hills	Antelope Shale-E. Dome	0.877	*c*	0.50	*b*	8.047	7.995	10.666	12.381	16.400	16.619
Buena Vista	Buena Vista Hills	Antelope Shale-W. Dome	0.877	*c*	0.50	*b*	7.874	7.625	6.993	7.121	9.801	12.946
Buena Vista	Buena Vista Hills	555 Stevens	0.882	*c*	0.50	*b*	30.962	30.000	27.832	27.236	41.311	35.353
Bunker Gas	Field	Field total					0.978	0.089	0.060	0.150	0.093	0.073
Bunker Gas	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Bunker Gas		No breakdown by pool					0.978	0.089	0.060	0.150	0.093	0.073
Bunker Gas		Oil Zone					0.000	0.000	0.000	0.000	0.000	0.000
Burrel	Field	Field total					0.162	0.164	0.168	0.086	0.155	0.140

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Burrel	Field	Not matched to pool/*OQ*	0.876 *c*	0.90 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Burrel		Miocene	0.876 *c*	0.90 *c*	0.162	0.164	0.168	0.086	0.155	0.140
Cabrillo	Field	Field total			0.000	0.000	1.613	4.450	7.997	7.714
Cabrillo	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Cabrillo		Topanga			0.000	0.000	1.613	4.450	7.997	7.714
Cal Canal Gas	Field	Field total			3.554	3.198	3.899	3.803	3.576	3.933
Cal Canal Gas	Field	Not matched to pool/*OQ*	0.820 *c*	0.16 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Cal Canal Gas		Etchegoin	0.820 *c*	0.16 *c*	0.028	0.023	0.000	0.000	0.000	0.008
Cal Canal Gas		Stevens	0.820 *c*	0.16 *c*	3.526	3.175	3.899	3.803	3.576	3.925
Calders Corner	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Calders Corner	Field	Not matched to pool/*OQ*	0.850 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Calders Corner		Stevens	0.850 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Camden	Field	Field total			0.181	0.216	0.197	0.179	0.196	0.215
Camden	Field	Not matched to pool/*OQ*	0.860 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Camden		Miocene	0.860 *c*		0.181	0.216	0.197	0.179	0.196	0.215
Canada Larga	Field	Field total			0.000	0.000	0.000	0.000	0.047	0.356
Canada Larga	Field	Not matched to pool/*OQ*	0.904 *c*		0.000	0.000	0.000	0.000	0.000	0.356
Canal	Field	Field total			5.283	4.238	3.664	4.367	4.166	5.189
Canal	Field	Not matched to pool/*OQ*	0.845 *c*	0.50 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Canal	Main Area	Gas Zone	0.845 *c*	0.50 *b,c*	0.000	0.000	0.000	0.000	0.000	0.045
Canal	Main Area	Upper Stevens	0.850 *c*	0.41 *c*	0.555	0.395	0.425	0.411	0.354	0.299
Canal	Main Area	Middle Stevens	0.850 *c*	0.41 *b*	1.938	1.458	1.708	1.643	1.415	1.197
Canal	Main Area	Lower Stevens	0.850 *c*	0.70 *c*	0.000	0.000	0.000	0.000	0.060	0.523
Canal	Pioneer Canal	Upper Stevens	0.833 *c*	0.26 *b*	1.141	0.869	0.442	0.626	0.608	0.740
Canal	Pioneer Canal	Lower Stevens	0.844 *c*	0.70 *b*	1.641	1.517	1.088	1.687	1.728	2.430
Canfield Ranch	Field	Field total			41.285	38.025	28.738	24.287	19.103	18.590
Canfield Ranch	Field	Not matched to pool/*OQ*	0.877 *b,c*	0.37 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Gosford East	Stevens	0.855 *b*	0.37 *b*	35.342	32.939	24.698	20.720	16.583	16.483
Canfield Ranch	Gosford East	Larimer Equiv.	0.877 *b,c*	0.37 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Gosford South	Stevens	0.868 *c*	0.37 *c*	5.696	4.713	3.697	3.238	2.180	1.791
Canfield Ranch	Gosford West	Stevens	0.930 *c*	0.37 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Old Area	Etchegoin	0.877 *b,c*	0.37 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Old Area	Stevens	0.887 *c*	0.37 *c*	0.247	0.374	0.343	0.329	0.340	0.316
Canfield Ranch	Old River Area	Stevens	0.845 *c*	0.37 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Careaga Canyon	Field	Field total			0.273	0.303	0.139	2.943	1.872	1.811
Careaga Canyon	Field	Not matched to pool/*OQ*	0.853 *c*	0.34 *c*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Careaga Canyon	Old Area	Monterey	0.855 *c*	0.20 *c*	0.273	0.303	0.139	0.065	0.000	0.000
Careaga Canyon	San Antonio Crk.	Monterey	0.850 *c*	0.47 *c*	0.000	0.000	0.000	2.878	1.872	1.811
Carneros Creek	Field	Field total			5.693	5.261	6.588	7.321	8.155	5.688
Carneros Creek	Field	Not matched to pool/*OQ*	0.913 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Carneros Creek		Button Bed	0.979 *c*		0.607	0.677	0.733	0.744	0.770	0.773
Carneros Creek		Carneros	0.916 *c*		0.096	0.086	0.073	0.069	0.057	0.045
Carneros Creek		Phacoides	0.871 *c*		0.472	0.407	0.251	0.243	0.368	0.216
Carneros Creek		Point of Rocks	0.885 *c*		4.517	4.091	5.530	6.265	6.960	4.671
Carpinteria Offshore	Field	Field total			82.509	80.415	82.592	83.660	78.051	73.980
Carpinteria Offshore	Field	Not matched to pool/*OQ*	0.895 *c*	1.88 *e*	82.509	80.415	82.592	83.660	78.051	73.980
Cascade	Field	Field total			67.505	64.173	51.856	43.285	33.814	30.889
Cascade	Field	Not matched to pool/*OQ*	0.910 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Cascade		No breakdown by pool	0.885 *c*		1.846	1.446	2.124	3.479	2.732	3.197
Cascade		Deep	0.885 *c*		65.659	62.727	49.731	39.806	31.082	27.692
Casmalia	Field	Field total			24.997	21.850	22.615	21.323	27.163	29.030
Casmalia	Field	Not matched to pool/*OQ*	0.959 *c*	2.80 *b*	24.997	21.850	22.615	21.323	27.163	29.030
Castaic Hills	Field	Field total			1.207	2.096	2.517	2.875	2.829	2.861
Castaic Hills	Field	Not matched to pool/*OQ*	0.937 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Golden	1.007 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Sterling	0.863 *c*	0.51 *b*	0.976	1.846	2.369	2.658	2.541	2.595
Castaic Hills		Sterling East	0.863 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Rynne-Fisher	0.860 *c*	0.51 *b*	0.232	0.250	0.148	0.218	0.288	0.266
Castaic Hills		Upper Radovich	1.014 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Lower Radovich	1.014 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Field	Field total			61.406	54.220	56.314	57.354	36.675	45.823
Cat Canyon	Field	Not matched to pool/*OQ*	0.988 *b,c*	4.74 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Central Area	Sisquoc	0.985 *b*	4.96 *b*	0.581	0.110	0.688	1.015	0.782	0.502
Cat Canyon	East Area		1.001 *c*	5.05 *c*	0.560	0.159	0.064	0.000	0.000	0.000
Cat Canyon	Gato Ridge Area		0.986 *c*	5.87 *c*	12.842	11.677	12.117	12.200	11.564	11.054
Cat Canyon	Olivera Canyon	Monterey	0.960 *b*	4.10 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Sisquoc Area		1.006 *c*	4.50 *c*	27.110	27.415	23.985	23.848	12.142	19.625
Cat Canyon	Tinaquaic Area	Monterey	1.022 *c*	4.96 *b*	0.000	0.000	0.304	3.158	3.155	2.823
Cat Canyon	West Area	No breakdown by pool	0.953 *c*	3.74 *c*	20.313	14.859	19.157	17.132	9.031	11.819
Cat Canyon	West Area	S6-S6A-Gas Zone	0.988 *b,c*	4.74 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Chaffee Canyon	Field	Field total			0.406	0.328	0.366	0.374	0.288	0.282
Chaffee Canyon	Field	Not matched to pool/*OQ*	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Chaffee Canyon		Pliocene-Gas Zone	0.845	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Chaffee Canyon		Eocene	0.845	*c*			0.406	0.328	0.366	0.374	0.288	0.282
Cheviot Hills	Field	Field total					12.047	11.644	9.944	9.194	9.096	8.489
Cheviot Hills	Field	Not matched to pool/*OQ*	0.869	*b*	0.70	*b*	0.000	0.000	0.000	0.000	9.096	0.000
Cheviot Hills		Pliocene	0.889	*b*	0.87	*b*	11.000	10.553	9.069	8.209	7.745	7.212
Cheviot Hills		Miocene	0.849	*b*	0.53	*b*	1.047	1.091	0.875	0.985	1.351	1.277
Chico-Martinez	Field	Field total					1.393	1.534	0.598	0.882	0.719	0.476
Chico-Martinez	Field	Not matched to pool/*OQ*	0.948	*c*			1.393	1.534	0.598	0.882	0.719	0.476
Chino-Soquel	Field	Field total					0.120	0.116	0.296	0.313	0.216	0.100
Chino-Soquel	Field	Not matched to pool/*OQ*	0.928	*c*			0.120	0.116	0.296	0.313	0.216	0.100
Cienaga Canyon	Field	Field total					0.835	0.715	1.167	1.526	3.093	1.809
Cienaga Canyon	Field	Not matched to pool/*OQ*	0.934	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Cienaga Canyon		Temblor	0.934	*c*			0.835	0.715	1.167	1.526	3.093	1.809
Coalinga	Field	Field total					953.461	936.150	913.298	893.683	913.671	934.137
Coalinga	Field	Not matched to pool/*OQ*	0.887	*c*	0.37	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga		Temblor	0.931	*c*	0.64	*c*	953.461	936.150	913.298	893.683	913.671	934.137
Coalinga		Cretacious	0.843	*c*	0.10	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga East Ext.	Field	Field total					6.825	6.010	2.788	4.748	4.772	3.550
Coalinga East Ext.	Field	Not matched to pool/*OQ*	0.865	*b,c*	0.26	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga East Ext.	Coalinga Nose	Vaqueros	0.845	*c*	0.22	*c*	1.823	1.528	1.747	1.213	0.877	0.373
Coalinga East Ext.	Coalinga Nose	Gatchell	0.868	*b*	0.25	*b*	5.002	4.482	1.041	3.536	3.895	3.177
Coalinga East Ext.	Northeast Area	Gatchell	0.883	*b*	0.31	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee North	Field	Field total					25.506	25.106	23.549	23.388	26.236	24.788
Coles Levee North	Field	Not matched to pool/*OQ*	0.805	*b,c*	0.49	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee North		Gas Zone	0.805	*b,c*	0.49	*b,c*	0.006	0.000	0.000	0.000	0.000	0.000
Coles Levee North		Stevens Undifferentiated	0.859	*b*	0.58	*b*	25.500	25.106	23.549	23.388	26.236	24.788
Coles Levee North		Miocene-Eocene	0.751	*c*	0.39	*c*	0.000	0.000	0.000	0.000	0.000	3.482
Coles Levee South	Field	Field total					14.511	15.111	15.375	15.098	14.667	10.912
Coles Levee South	Field	Not matched to pool/*OQ*	0.834	*b,c*	0.38	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee South		Gas Zone	0.834	*b,c*	0.38	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee South		Stevens	0.840	*b*	0.38	*b*	14.511	15.111	15.375	15.098	14.667	14.393
Coles Levee South		Nozu	0.829	*c*	0.38	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Comanche Point	Field	Field total					0.551	0.586	0.723	0.576	0.976	0.868
Comanche Point	Field	Not matched to pool/*OQ*	0.954	*c*	1.16	*c*	0.551	0.000	0.000	0.000	0.000	0.000
Comanche Point		No breakdown by pool	0.966	*c*	1.16	*c*	0.000	0.586	0.723	0.576	0.324	0.336
Comanche Point		Santa Margarita	0.966	*c*	1.16	*c*	0.000	0.000	0.000	0.000	0.652	0.532

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Coyote East	Field	Field total			44.041	40.007	37.966	35.872	35.938	36.258
Coyote East	Field	Not matched to pool/*OQ*	0.930 *c*	1.16 *c*	44.041	40.007	37.966	35.872	35.938	36.258
Cuyama South	Field	Field total			44.548	44.524	42.754	42.188	40.259	36.443
Cuyama South	Field	Not matched to pool/*OQ*	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	Main Area	No breakdown by pool	0.863 *b*	0.42 *b*	41.633	41.361	38.291	38.915	38.512	32.150
Cuyama South	Main Area	52-1-Gas Zone	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	Southeast Area	Santa Margarita-Gas Zone	0.863 *b*	0.42 *b*	0.000	0.024	0.784	0.630	0.359	0.267
Cuyama South	Southeast Area	Santa Margarita	0.863 *b*	0.42 *b*	2.915	3.140	3.679	2.643	1.387	1.023
Cuyama South	Southeast Area	Cox	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	East Area	L. Miocene	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Field	Field total			3,007.267	2,835.179	2,934.520	2,923.618	2,861.509	2,787.928
Cymric	Field	Not matched to pool/*OQ*	0.907 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Cymric Flank Area	Cameros	0.842 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.220
Cymric	Cymric Flank Area	Phacoides	0.860 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Salt Creek Main	Etchegoin	0.979 *c*	1.16 *b*	0.276	0.336	0.339	0.345	0.557	0.522
Cymric	Salt Creek Main	Cameros West	0.943 *b*	0.69 *b*	1.922	1.876	1.461	0.805	0.854	0.999
Cymric	Salt Creek Main	Cameros Unit	0.937 *c*	0.69 *b*	11.588	10.496	8.999	8.658	6.181	7.259
Cymric	Salt Creek Main	Phacoides	0.922 *c*	0.44 *b*	2.160	2.109	1.996	2.293	2.320	1.488
Cymric	Salt Creek West	Phacoides	0.922 *c*	0.44 *b*	0.000	0.123	0.260	0.145	0.181	0.170
Cymric	Sheep Springs	Tulare	0.990 *c*	1.16 *b*	0.364	0.344	0.299	0.177	0.187	0.221
Cymric	Sheep Springs	Etchegoin	0.959 *c*	0.86 *b*	3.510	3.376	3.709	3.490	3.832	4.454
Cymric	Sheep Springs	Monterey	0.925 *c*	0.69 *b*	0.000	0.000	0.028	0.085	0.267	0.000
Cymric	Sheep Springs	Cameros	0.916 *c*	0.44 *b*	2.269	1.749	1.424	4.160	6.845	7.221
Cymric	Sheep Springs	Phacoides	0.860 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Sheep Springs	Oceanic	0.820 *c*	0.23 *b*	0.014	0.012	0.010	0.010	0.008	0.011
Cymric	Welport Area	No breakdown by pool	0.907 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Tulare-Antelope	0.979 *c*	1.16 *b*	145.560	279.075	287.711	253.195	295.886	295.336
Cymric	Welport Area	Tulare	0.979 *c*	1.16 *b*	1,251.681	1,146.959	1,175.553	1,045.810	963.330	892.743
Cymric	Welport Area	Etchegoin	0.887 *c*	0.86 *b*	1,302.987	1,147.315	1,209.081	1,347.150	1,329.735	1,365.377
Cymric	Welport Area	San Joaquin	0.985 *c*	1.38 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Reef Ridge-Antelope	0.960 *c*	0.86 *b*	270.520	226.043	228.528	248.238	240.793	203.307
Cymric	Welport Area	McDonald-Devilwater	0.891 *c*	0.86 *b*	0.016	4.855	2.637	1.481	1.879	1.195
Cymric	Welport Area	Cameros	0.866 *c*	0.44 *b*	2.170	0.715	0.638	1.246	3.196	4.153
Cymric	Welport Area	Agua	0.871 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Phacoides	0.860 *c*	0.44 *b*	0.161	0.211	2.117	2.321	1.264	0.640
Cymric	Welport Area	Oceanic	0.821 *c*	0.23 *b*	0.000	0.000	0.000	0.000	0.622	0.902

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Cymric	Welport Area	Point of Rocks	0.788 *c*	0.23 *b*	12.068	9.586	9.729	4.010	3.573	1.709
Deer Creek	Field	Field total			6.307	6.694	7.017	7.071	8.049	8.978
Deer Creek	Field	Not matched to pool/*OQ*	0.921 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Deer Creek		Santa Margarita	0.855 *c*		6.307	6.694	7.017	7.071	8.049	8.978
Deer Creek North	Field	Field total			0.000	0.072	0.172	0.159	0.139	0.019
Deer Creek North	Field	Not matched to pool/*OQ*	0.986 *c*		0.000	0.072	0.172	0.159	0.000	0.019
Del Valle	Field	Field total			10.605	8.325	9.465	9.356	9.690	10.434
Del Valle	Field	Not matched to pool/*OQ*	0.887 *c*	1.15 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Del Valle	Kinler Area		0.934 *c*	1.15 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Del Valle	Main Area		0.853 *c*	1.15 *b*	6.646	4.949	6.204	6.145	6.368	7.063
Del Valle	South Area		0.875 *c*	1.14 *b*	3.959	3.377	3.260	3.211	3.322	3.333
Denverton Crk. Gas	Field	Field total			0.189	0.158	0.096	0.052	0.032	0.009
Denverton Crk. Gas	Field	Not matched to pool/*OQ*			0.189	0.158	0.096	0.052	0.032	0.009
Devils Den	Field	Field total			3.040	3.629	4.116	3.761	3.266	3.087
Devils Den	Field	Not matched to pool/*OQ*	0.917 *b,c*	0.41 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Devils Den	Alferitz Area	No breakdown by pool	0.931 *b*	0.37 *b*	2.140	2.890	3.444	3.068	2.734	2.559
Devils Den	Alferitz Area	Eocene Gas Zone	0.887 *c*	0.57 *b*	0.207	0.194	0.172	0.152	0.103	0.132
Devils Den	Bates Area		0.904 *c*	0.14 *c*	0.055	0.081	0.095	0.140	0.112	0.111
Devils Den	Old Area		0.945 *c*	0.57 *b*	0.639	0.464	0.405	0.401	0.317	0.285
Dominguez	Field	Field total			1.421	1.337	1.317	1.286	1.227	1.179
Dominguez	Field	Not matched to pool/*OQ*	0.871 *c*	0.76 *b*	1.421	1.337	1.317	1.286	1.227	1.179
Dos Cuadras OCS	Field	Field total			245.909	227.487	247.484	215.117	220.371	210.282
Dos Cuadras OCS	Field	Not matched to pool/*OQ*	0.881 *c*	1.11 *b*	245.909	227.487	247.484	215.117	220.371	210.282
Dunnigan Hills Gas	Field	Field total			0.000	0.000	0.000	0.000	0.001	0.000
Dunnigan Hills Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Dunnigan Hills Gas	Main Area				0.000	0.000	0.000	0.000	0.001	0.000
Dunnigan Hills Gas	Southeast Area	Winters			0.000	0.000	0.000	0.000	0.000	0.000
Dutch Slough Gas	Field	Field total			0.097	0.357	0.587	0.408	0.174	0.066
Dutch Slough Gas	Field	Not matched to pool/*OQ*			0.097	0.357	0.587	0.408	0.000	0.066
Edison	Field	Field total			105.532	102.366	107.857	106.296	107.886	107.254
Edison	Field	Not matched to pool/*OQ*	0.914 *c*	0.34 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison	Edison Groves		0.970 *c*	0.70 *c*	3.346	3.463	4.555	3.059	3.614	6.797
Edison	Jeppi Area		0.851 *c*	0.42 *b*	1.246	1.713	1.593	1.774	1.907	1.934
Edison	Main Area		0.933 *c*	0.56 *c*	59.822	57.194	58.143	58.630	58.082	53.381
Edison	Portals-Fairfax		0.953 *c*	0.20 *c*	4.989	4.612	5.309	5.352	5.502	9.735
Edison	Race Track Hill		0.905 *c*	0.22 *c*	27.452	27.834	30.109	29.621	31.108	26.896

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Edison	West Area	No breakdown by pool	0.901	*c*	0.20	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison	West Area	Santa Margarita	0.966	*c*	0.20	*c*	0.069	0.043	0.035	0.152	0.179	0.169
Edison	West Area	Chanac-Jewett	0.920	*c*	0.20	*c*	7.766	6.898	7.516	7.033	6.879	6.286
Edison	West Area	Pyramid Hill-Vedder	0.816	*c*	0.20	*c*	0.843	0.608	0.596	0.673	0.615	0.398
Edison, Northeast	Field	Field total					0.138	0.236	0.551	0.000	0.000	0.000
Edison, Northeast	Field	Not matched to pool/*OQ*	0.979	*c*	0.20	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison, Northeast		Chanac	0.979	*c*	0.20	*c*	0.138	0.236	0.551	0.000	0.000	0.000
El Segundo	Field	Field total					2.525	2.585	2.394	2.392	3.931	4.146
El Segundo	Field	Not matched to pool/*OQ*	0.949	*b*	4.33	*b*	2.525	2.585	2.394	2.392	3.931	4.146
Elk Hills	Field	Field total					2,952.868	2,867.320	2,732.544	2,602.608	2,371.953	2,005.087
Elk Hills	Field	Not matched to pool/*OQ*	0.882	*c*	0.64	*b*	0.000	0.000	0.000	0.000	0.000	177.090
Elk Hills		No breakdown by pool	0.882	*c*	0.64	*b*	0.000	0.217	0.742	0.790	1.085	1.190
Elk Hills		Tulare	1.000	*c*	1.02	*b*	6.677	6.074	7.999	8.305	6.875	4.004
Elk Hills		Gas Zone	0.924	*b*	0.82	*b*	0.000	0.000	0.648	0.834	0.436	8.212
Elk Hills		4th Mya	0.947	*c*	0.82	*b*	9.931	9.940	7.909	8.230	9.450	5.128
Elk Hills		Upper Undifferentiated	0.905	*c*	0.75	*b*	1,637.570	1,601.698	1,554.117	1,542.450	1,337.456	1,190.117
Elk Hills		Upper Sub-Scalez	0.859	*c*	0.83	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Elk Hills		Reef Ridge	0.882	*c*	0.64	*b*	0.109	0.228	0.007	0.000	0.000	14.471
Elk Hills		Stevens	0.845	*c*	0.49	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Elk Hills		Stevens 29R	0.845	*c*	0.49	*b*	226.734	227.119	226.399	205.279	199.585	178.097
Elk Hills		Stevens Northwest	0.904	*c*	0.49	*b*	153.316	142.235	134.023	120.068	118.314	124.094
Elk Hills		Stevens 31S	0.845	*c*	0.49	*b*	915.403	877.087	797.902	711.270	674.112	597.304
Elk Hills		Cameros	0.780	*c*	0.63	*b*	2.807	2.432	2.587	5.234	24.640	74.029
Elk Hills		Agua	0.840	*c*			0.322	0.290	0.210	0.148	0.000	0.000
Elwood S. Offshore	Field	Field total					188.467	165.575	176.621	179.733	147.853	146.535
Elwood S. Offshore	Field	Not matched to pool/*OQ*	0.870	*c*	1.10	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Elwood S. Offshore	Coal Oil Point		0.870	*c*	1.10	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Elwood S. Offshore	Main Area	Sisquoc	0.880	*c*	2.02	*c*	0.276	0.130	0.214	0.280	0.155	0.144
Elwood S. Offshore	Main Area	Monterey	0.880	*c*	2.02	*c*	188.191	162.407	174.816	177.367	145.882	142.611
Elwood S. Offshore	Main Area	Rincon	0.860	*c*	0.17	*b*	0.000	0.248	1.465	2.087	1.816	3.779
Elwood S. Offshore	Main Area	Sespe	0.860	*c*	0.20	*c*	0.000	2.790	0.126	0.000	0.000	0.000
English Colony	Field	Field total					0.000	0.000	0.000	0.000	0.000	0.000
English Colony	Field	Not matched to pool/*OQ*	0.855	*c*			0.000	0.000	0.000	0.000	0.000	0.000
English Colony		Stevens	0.855	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Esperanza	Field	Field total					1.468	0.880	1.493	1.559	1.363	1.415
Esperanza	Field	Not matched to pool/*OQ*	0.893	*c*			1.468	0.880	1.493	1.559	1.363	1.415

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Eureka Canyon	Field	Field total					0.602	0.796	0.867	0.578	0.538	0.493
Eureka Canyon	Field	Not matched to pool/*OQ*	0.899	*c*			0.602	0.796	0.867	0.578	0.538	0.493
Fillmore	Field	Field total					0.091	0.113	0.049	0.024	0.000	0.000
Fillmore	Field	Not matched to pool/*OQ*	0.865	*c*	0.05	*c*	0.091	0.113	0.049	0.024	0.000	0.000
Fruitvale	Field	Field total					66.923	70.502	74.849	78.749	76.198	71.804
Fruitvale	Field	Not matched to pool/*OQ*	0.939	*b*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Calloway Area		0.939	*b*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Greenacres Area	Billington	0.939	*b*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Greenacres Area	Plank	0.939	*b*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Main Area		0.939	*b*	0.86	*b*	66.923	70.502	74.849	78.749	76.198	71.804
Grand Island Gas	Field	Field total					0.008	0.000	0.000	0.000	0.000	0.000
Grand Island Gas	Field	Not matched to pool/*OQ*					0.008	0.000	0.000	0.000	0.000	0.000
Greeley	Field	Field total					19.841	18.241	17.146	16.888	26.587	20.542
Greeley	Field	Not matched to pool/*OQ*	0.839	*b*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Greeley		Stevens Undifferentiated	0.841	*b*	0.28	*b*	2.081	1.890	1.800	2.287	8.787	4.514
Greeley		Upper Stevens	0.841	*b*	0.28	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Greeley		Olcœse 12-21	0.839	*b*	0.31	*b*	4.692	3.435	3.542	3.103	3.520	3.253
Greeley		Rio Bravo-Vedder	0.837	*b*	0.29	*b*	13.068	12.916	11.645	11.497	14.281	12.775
Guijarral Hills	Field	Field total					0.994	0.689	0.330	0.235	0.108	0.066
Guijarral Hills	Field	Not matched to pool/*OQ*	0.834	*b*	0.61	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Smith	0.847	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Smith & Allison	0.844	*c*	0.63	*b*	0.994	0.689	0.330	0.235	0.108	0.066
Guijarral Hills	Main Area	Allison	0.840	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Leda	0.850	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Leda North	0.841	*b*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Dessel	0.893	*c*	0.59	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Gatchell	0.877	*c*	0.31	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Northwest Area	Leda	0.842	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Polvadero Area	Sanger	0.874	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Polvadero Area	Bourdieu	0.877	*c*	0.59	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	West Area	Leda	0.842	*c*	0.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Half Moon Bay	Field	Field total					0.000	0.000	0.000	0.000	0.020	0.070
Half Moon Bay	Field	Not matched to pool/*OQ*	0.874	*c*			0.000	0.000	0.000	0.000	0.020	0.070
Hasley Canyon	Field	Field total					6.199	8.127	12.387	13.083	11.413	8.979
Hasley Canyon	Field	Not matched to pool/*OQ*	0.963	*c*	5.49	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Hasley Canyon		Val Verde	0.963	*c*	5.49	*b*	6.199	8.127	12.387	13.083	11.413	8.979

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Helm	Field	Field total			8.340	5.849	8.923	12.379	15.920	16.010
Helm	Field	Not matched to pool/*OQ*	0.827 *b,c*	0.27 *b,c*	0.000	0.000	0.155	0.000	0.000	0.000
Helm	Main Area	Miocene	0.837 *b*	0.26 *b*	3.864	3.646	6.828	6.101	11.291	11.273
Helm	Main Area	Eocene & Cretaceous	0.808 *c*	0.30 *c*	2.565	1.771	1.794	6.170	4.540	4.663
Helm	Southeast Area	Miocene	0.837 *b*	0.26 *b*	1.911	0.432	0.146	0.108	0.089	0.078
Holser	Field	Field total			4.055	2.816	3.275	3.407	3.071	2.755
Holser	Field	Not matched to pool/*OQ*	0.923 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Holser		Conglomerate	0.953 *c*		0.065	0.042	0.053	0.052	0.046	0.040
Holser		Holser-Nuevo	0.893 *c*		3.990	2.773	3.219	3.354	3.025	2.715
Hondo Offshore	Field	Field total			1,223.927	973.919	894.604	899.656	873.872	753.598
Hondo Offshore	Field	Not matched to pool/*OQ*	0.929 *e*	4.29 *e*	1,223.927	973.919	894.604	899.656	873.872	753.598
Honor Rancho	Field	Field total			10.736	11.837	11.332	14.287	13.931	12.957
Honor Rancho	Field	Not matched to pool/*OQ*	0.842 *c*	0.40 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Honor Rancho	Main Area	Gabriel	0.840 *c*	0.40 *b*	0.107	0.063	0.129	0.229	0.248	0.257
Honor Rancho	Main Area	Rancho	0.850 *c*	0.40 *b*	0.000	0.000	0.000	1.047	1.146	0.525
Honor Rancho	Main Area	Wayside	0.850 *c*	0.40 *b*	2.516	2.193	1.424	2.592	1.980	1.583
Honor Rancho	Southeast Area	Wayside 13	0.830 *c*	0.40 *b*	8.113	9.582	9.779	10.418	10.558	10.592
Hopper Canyon	Field	Field total			1.863	0.364	1.134	1.184	1.321	1.163
Hopper Canyon	Field	Not matched to pool/*OQ*	0.942 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Hopper Canyon	Main Area		0.911 *c*		1.863	0.364	1.134	1.184	1.321	1.163
Hopper Canyon	North Area		0.973 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Howard Townsite	Field	Field total			1.590	1.463	1.032	0.921	1.402	1.104
Howard Townsite	Field	Not matched to pool/*OQ*	0.835 *c*	0.28 *c*	1.590	1.463	1.032	0.921	1.402	1.104
Hueneme Offshore	Field	Field total			17.943	23.187	23.089	21.055	19.300	17.322
Hueneme Offshore	Field	Not matched to pool/*OQ*	0.968 *c*	3.73 *e*	17.943	23.187	23.089	21.055	19.300	17.322
Huntington Beach	Field	Field total			426.468	393.104	354.270	325.566	308.982	292.617
Huntington Beach	Field	Not matched to pool/*OQ*	0.929 *b*	1.60 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Huntington Beach	Offshore		0.929 *b*	1.60 *b*	337.116	309.991	276.390	251.715	237.291	219.935
Huntington Beach	Onshore		0.929 *b*	1.60 *b*	89.352	83.113	77.880	73.851	71.691	69.945
Hyperion	Field	Field total			1.446	1.681	1.582	1.627	1.657	1.560
Hyperion	Field	Not matched to pool/*OQ*	0.956 *c*		1.446	1.681	1.582	1.627	1.657	1.560
Inglewood	Field	Field total			450.216	458.258	528.095	492.660	493.945	447.759
Inglewood	Field	Not matched to pool/*OQ*	0.929 *b*	2.24 *b*	450.216	458.258	528.095	492.660	493.945	447.759
Jacalitos	Field	Field total			9.944	11.819	15.437	21.410	26.355	20.136
Jacalitos	Field	Not matched to pool/*OQ*	0.832 *b*	0.34 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Jacalitos		Temblor	0.832 *b*	0.34 *b*	9.944	11.819	15.437	21.410	26.355	20.136

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Jasmin	Field	Field total			2.820	3.213	4.120	6.647	13.511	16.997
Jasmin	Field	Not matched to pool/*OQ*	0.973 *b*		0.000	0.000	0.000	0.000	0.000	0.000
Jasmin		Pyramid Hill	0.973 *b*		0.000	0.000	0.000	0.000	0.000	0.000
Jasmin		Cantleberry	0.973 *b*		2.820	3.213	4.120	6.647	13.511	16.997
Kern Bluff	Field	Field total			1.654	1.593	1.456	1.411	1.281	1.353
Kern Bluff	Field	Not matched to pool/*OQ*	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Bluff		Miocene	0.973 *c*	0.63 *c*	1.654	1.593	1.456	1.411	1.281	1.353
Kern Bluff		Transition-Santa Margarita	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Bluff		Vedder	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Front	Field	Field total			260.566	240.570	253.748	270.374	341.787	395.301
Kern Front	Field	Not matched to pool/*OQ*	0.968 *b*	0.89 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Front		No breakdown by pool	0.968 *b*	0.89 *b*	260.566	231.601	229.949	229.821	239.416	223.144
Kern Front		Etchegoin	0.973 *c*	0.94 *b*	0.000	8.969	23.799	40.553	102.370	172.158
Kern River	Field	Field total			5,570.723	5,253.662	4,899.065	4,791.678	4,682.727	4,592.039
Kern River	Field	Not matched to pool/*OQ*	0.979 *b*	1.15 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kern River		Kern River	0.983 *b*	1.16 *b*	5,570.723	5,253.662	4,897.798	4,790.897	4,680.235	4,590.668
Kern River		Jewett	0.977 *b*	1.14 *b*	0.000	0.000	0.000	0.000	0.000	0.060
Kern River		Vedder	0.823 *c*	0.05 *c*	0.000	0.000	1.267	0.781	2.492	1.311
Kettleman Mid. Dome	Field	Field total			0.094	0.182	0.493	3.775	6.632	5.812
Kettleman Mid. Dome	Field	Not matched to pool/*OQ*	0.842 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Etchegoin-Jacalitos	0.976 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Temblor	0.757 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Vaqueros	0.830 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Kreyenhagen	0.847 *c*		0.094	0.182	0.493	2.093	2.879	2.374
Kettleman Mid. Dome		Eocene-McAdams	0.797 *c*		0.000	0.000	0.000	1.681	3.753	3.438
Kettleman N. Dome	Field	Field total			13.594	17.166	20.274	11.970	0.585	5.655
Kettleman N. Dome	Field	Not matched to pool/*OQ*	0.771 *b*	0.19 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		No breakdown by pool	0.771 *b*	0.19 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		Temblor	0.835 *b*	0.35 *b*	7.731	10.381	14.247	8.045	0.047	3.241
Kettleman N. Dome		Whepley	0.832 *c*	0.13 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		Vaqueros	0.843 *c*	0.28 *c*	2.084	2.491	1.980	1.146	0.501	0.697
Kettleman N. Dome		Kreyenhagen	0.871 *c*	0.31 *c*	3.447	3.823	3.704	2.515	0.036	1.310
Kettleman N. Dome		Upper McAdams	0.826 *c*	0.31 *c*	0.014	0.229	0.048	0.022	0.000	0.000
Kettleman N. Dome		Lower McAdams	0.859 *c*	0.31 *c*	0.317	0.243	0.295	0.242	0.000	0.407
La Goleta Gas	Field	Field total			0.041	0.035	0.000	0.041	0.109	0.015
La Goleta Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
La Goleta Gas		Vaqueros			0.041	0.035	0.000	0.041	0.109	0.015
La Goleta Gas		Sespe			0.000	0.000	0.000	0.000	0.000	0.000
La Honda	Field	Field total			0.000	0.213	0.300	0.292	0.468	0.458
La Honda	Field	Not matched to pool/*OQ*	0.867 *c*		0.000	0.000	0.000	0.000	0.000	0.000
La Honda	Main Area		0.867 *c*		0.000	0.000	0.000	0.000	0.000	0.000
La Honda	South Area		0.913 *c*		0.000	0.213	0.300	0.292	0.468	0.458
Landslide	Field	Field total			15.938	14.074	12.863	9.399	6.673	5.840
Landslide	Field	Not matched to pool/*OQ*	0.872 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Landslide	Boulder Creek	Stevens	0.872 *c*		1.450	1.418	1.320	1.250	1.373	1.529
Landslide	Main Area	Stevens	0.872 *c*		14.488	12.656	11.543	8.149	5.301	4.311
Las Cienagas	Field	Field total			60.337	67.463	81.534	78.275	79.911	78.139
Las Cienagas	Field	Not matched to pool/*OQ*	0.865 *c*	0.58 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Las Cienagas	Fourth Avenue		0.869 *c*	0.58 *b*	2.845	2.961	6.386	6.348	7.429	10.624
Las Cienagas	Good Shepard		0.871 *c*	0.58 *b*	0.000	0.387	2.317	0.371	0.000	0.000
Las Cienagas	Jefferson Area		0.861 *c*	0.58 *b*	18.804	24.896	32.301	34.795	33.363	29.179
Las Cienagas	Murphy Area	No breakdown by pool	0.862 *c*	0.58 *b*	33.139	31.557	40.531	36.761	37.639	34.781
Las Cienagas	Murphy Area	A,B,C & PE zones, B Block	0.870 *c*	0.58 *b*	5.550	7.662	0.000	0.000	1.480	3.554
Las Cienagas	Pacific Electric		0.855 *c*	0.58 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas	Field	Not matched to pool/*OQ*	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas		Las Llajas	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas		Santa Susana	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Lawndale	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Lawndale	Field	Not matched to pool/*OQ*	0.882 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lawndale		Upper	0.879 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lawndale		Schist Conglomerate	0.887 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lindsey Slough Gas	Field	Field total			1.479	0.561	0.761	0.943	0.908	0.754
Lindsey Slough Gas	Field	Not matched to pool/*OQ*			1.479	0.561	0.761	0.943	0.908	0.754
Livermore	Field	Field total			1.638	1.794	1.508	2.094	2.934	2.870
Livermore	Field	Not matched to pool/*OQ*	0.905 *c*		1.638	1.794	1.508	2.094	2.934	2.870
Lompoc	Field	Field total			16.338	15.128	24.546	26.179	31.576	34.809
Lompoc	Field	Not matched to pool/*OQ*	0.959 *b*	3.50 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Lompoc	Main Area	Monterey	0.932 *c*	3.50 *b*	9.961	8.524	18.262	20.572	26.510	29.763
Lompoc	Northwest Area	Monterey	0.945 *c*	1.84 *c*	6.377	6.605	6.284	5.607	5.067	5.047
Long Beach	Field	Field total			229.740	238.851	240.859	235.523	238.202	229.985
Long Beach	Field	Not matched to pool/*OQ*	0.918 *b*	1.30 *b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific		Sulfur		Production by year ($m^3 \cdot 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity		% wt.		2004	2005	2006	2007	2008	2009
Long Beach	Northwest Ext.		0.959	*c*	1.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Long Beach	Old Area	No breakdown by pool	0.918	*b*	1.30	*b*	0.000	0.000	0.029	0.000	0.000	0.000
Long Beach	Old Area	Wardlow	0.865	*c*	1.30	*b*	2.632	2.500	2.186	1.700	1.789	2.304
Long Beach	Old Area	Alamitos	0.918	*b*	1.29	*b*	5.305	5.491	4.809	6.172	6.793	5.739
Long Beach	Old Area	Brown	0.911	*c*	1.06	*b*	0.382	1.378	2.481	2.429	2.089	0.748
Long Beach	Old Area	Deep	0.865	*c*	1.06	*b*	0.084	0.063	0.000	0.000	0.000	0.163
Long Beach	Old Area	Others	0.912	*b*	1.30	*b*	217.170	225.130	227.091	220.565	223.199	216.636
Long Beach	Recreation Park		0.893	*c*	1.30	*b*	4.167	4.289	4.264	4.658	4.331	4.395
Long Beach Airport	Field	Field total					0.175	0.380	1.310	1.917	1.808	1.750
Long Beach Airport	Field	Not matched to pool/*OQ*	0.855	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Long Beach Airport		Deep	0.855	*c*			0.175	0.380	1.310	1.917	1.808	1.750
Los Alamos	Field	Field total					0.000	0.083	0.000	0.375	0.000	0.035
Los Alamos	Field	Not matched to pool/*OQ*	0.845	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Los Alamos		Monterey	0.845	*c*			0.000	0.083	0.000	0.375	0.000	0.035
Los Angeles City	Field	Field total					0.397	0.304	0.255	0.235	0.205	0.202
Los Angeles City	Field	Not matched to pool/*OQ*	0.960	*c*			0.397	0.304	0.255	0.235	0.205	0.202
Los Angeles Downtn.	Field	Field total					15.111	14.233	1.945	0.924	5.319	5.167
Los Angeles Downtn.	Field	Not matched to pool/*OQ*	0.857	*c*	1.58	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles Downtn.		No breakdown by pool	0.857	*c*	1.58	*c*	15.111	14.233	1.945	0.924	5.319	5.167
Los Angeles Downtn.		Hill Gas Sands	0.857	*c*	1.58	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles East	Field	Field total					8.162	7.492	9.175	6.893	6.144	3.866
Los Angeles East	Field	Not matched to pool/*OQ*	0.853	*c*			8.162	7.492	9.175	6.893	6.144	3.866
Los Lobos	Field	Field total					0.000	0.000	1.299	8.663	2.693	0.000
Los Lobos	Field	Not matched to pool/*OQ*	0.949	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Los Lobos		Etchegoin	0.953	*c*			0.000	0.000	1.299	2.376	0.305	0.000
Los Lobos		Reef Ridge	0.904	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Los Lobos		Monterey	0.990	*c*			0.000	0.000	0.000	6.288	2.388	0.000
Lost Hills	Field	Field total					1,783.149	1,820.338	1,883.906	1,929.043	1,873.020	1,839.112
Lost Hills	Field	Not matched to pool/*OQ*	0.909	*b*	0.71	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Lost Hills		No breakdown by pool	0.909	*b*	0.71	*b*	0.000	0.000	0.000	0.000	0.000	0.872
Lost Hills		Tulare	0.934	*d*	0.83	*b*	14.142	32.613	43.832	55.518	101.136	151.557
Lost Hills		Tulare-Etchegoin	0.892	*b*	0.59	*b*	1,096.131	1,116.993	1,070.442	1,037.618	970.994	860.645
Lost Hills		Etchegoin	0.858	*b*	0.33	*b*	39.465	136.192	291.041	404.895	418.818	456.193
Lost Hills		Etchegoin-Cahn	0.909	*b*	0.71	*b*	145.947	138.768	126.662	113.640	97.778	116.788
Lost Hills		Cahn	0.880	*c*	0.71	*b*	482.263	389.604	345.600	313.022	279.407	226.494
Lost Hills		Devilwater	0.865	*c*	0.71	*b*	3.518	3.152	2.296	4.351	4.886	22.534

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Lost Hills		Carneros	0.865 *c*	0.71 *b*	0.000	0.000	0.000	0.000	0.000	0.354
Lost Hills		Antelope/McDonald	0.909 *b*	0.71 *b*	1.683	3.015	4.032	0.000	0.000	3.789
Lost Hills Northwest	Field	Field total			3.378	3.019	2.831	2.434	3.201	3.407
Lost Hills Northwest	Field	Not matched to pool/*OQ*	0.910 *c*	0.33 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lost Hills Northwest		Etchegoin	0.885 *c*	0.33 *c*	2.084	1.946	1.866	1.632	2.257	2.566
Lost Hills Northwest		Antelope Shale	0.934 *c*	0.33 *c*	1.293	1.073	0.965	0.803	0.942	0.841
Lynch Canyon	Field	Field total			0.000	4.818	10.225	17.692	20.365	23.877
Lynch Canyon	Field	Not matched to pool/*OQ*	0.993 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Lynch Canyon		Lanigan	0.993 *c*		0.000	4.818	10.225	17.692	20.365	23.877
Mahala	Field	Field total			0.444	0.340	0.416	0.287	0.246	0.105
Mahala	Field	Not matched to pool/*OQ*	0.908 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Mahala	Abacherli Area		0.923 *c*		0.404	0.314	0.327	0.262	0.216	0.079
Mahala	Mahala Area		0.921 *c*		0.040	0.026	0.021	0.025	0.029	0.025
Mahala	Mahala West Area		0.871 *c*		0.000	0.000	0.068	0.000	0.000	0.000
Mahala	Prado Dam Area		0.916 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Maine Prairie Gas	Field	Field total			0.006	0.065	0.004	0.002	0.002	0.004
Maine Prairie Gas	Field	Not matched to pool/*OQ*			0.006	0.065	0.004	0.002	0.002	0.004
McCool Ranch	Field	Field total			0.000	0.000	0.000	0.000	0.618	0.194
McCool Ranch	Field	Not matched to pool/*OQ*	0.988 *c*	1.20 *c*	0.000	0.000	0.000	0.000	0.000	0.000
McCool Ranch		Lombardi	0.988 *c*	1.20 *c*	0.000	0.000	0.000	0.000	0.618	0.194
McDonald Anticline	Field	Field total			11.087	13.129	12.258	12.192	14.821	9.591
McDonald Anticline	Field	Not matched to pool/*OQ*	0.903 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Bacon Hills Area	No breakdown by pool	0.907 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Bacon Hills Area	Antelope	0.979 *c*		0.048	0.163	0.141	0.000	0.373	0.207
McDonald Anticline	Bacon Hills Area	Oceanic	0.835 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Layman Area		0.913 *c*		11.040	12.965	12.118	12.192	14.448	9.384
McKittrick	Field	Field total			404.989	406.531	445.962	434.653	395.041	356.473
McKittrick	Field	Not matched to pool/*OQ*	0.957 *b*	0.96 *b*	0.000	0.000	0.000	0.000	0.000	0.000
McKittrick	Main Area	Tulare	0.962 *b*	0.96 *b*	2.328	3.061	16.439	42.995	40.318	42.625
McKittrick	Main Area	Upper	0.962 *b*	0.96 *b*	40.613	47.795	72.613	88.855	101.789	101.718
McKittrick	Main Area	Olig	0.973 *c*	0.96 *b*	0.000	0.000	0.000	0.000	1.108	11.094
McKittrick	Main Area	Antelope Shale	0.986 *c*	1.18 *c*	0.000	0.000	0.000	0.000	0.000	0.000
McKittrick	Main Area	Stevens	0.903 *c*	1.02 *c*	3.489	6.503	4.058	20.762	13.409	12.499
McKittrick	Northeast Area	Upper	0.949 *c*	0.96 *b*	258.285	259.160	264.895	213.143	174.632	138.170
McKittrick	Northeast Area	Tulare	0.962 *b*	0.96 *b*	5.470	9.659	16.536	14.865	13.971	15.596
McKittrick	Northeast Area	Antelope Shale	0.905 *c*	1.18 *c*	1.119	0.688	0.633	1.856	4.565	2.572

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
McKittrick	Northeast Area	Carneros	0.845 *c*	1.02 *c*	2.563	2.952	3.017	4.430	3.297	7.832
McKittrick	Northeast Area	Phacoides	0.860 *c*	1.02 *c*	31.246	28.859	27.197	21.257	23.673	22.428
McKittrick	Northeast Area	Phacoides/Oceanic	0.853 *c*	1.02 *c*	3.167	2.210	2.052	1.235	1.018	0.682
McKittrick	Northeast Area	Oceanic	0.845 *c*	1.02 *c*	21.512	14.625	8.188	3.733	4.402	4.267
McKittrick	Northeast Area	Point of Rocks	0.910 *c*	1.02 *c*	35.196	31.017	30.332	21.522	12.860	10.584
Medora Lake Gas	Field	Field total			0.013	0.047	0.042	0.030	0.010	0.000
Medora Lake Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Medora Lake Gas		Winters			0.013	0.047	0.042	0.030	0.010	0.000
Merrill Avenue Gas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Merrill Avenue Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Merrill Avenue Gas		Blewett			0.000	0.000	0.000	0.000	0.000	0.000
Midway-Sunset	Field	Field total			7,117.798	6,721.020	6,300.516	6,043.567	5,775.550	5,398.648
Midway-Sunset	Field	Not matched to pool/*OQ*	0.945 *b*	1.00 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Midway-Sunset	County Code 029		0.945 *b*	1.00 *b*	2,870.140	2,519.130	2,215.383	2,023.260	1,847.419	1,680.645
Midway-Sunset	County Code 030		0.945 *b*	1.00 *b*	4,244.114	4,198.429	4,080.051	4,014.579	3,923.591	3,711.220
Midway-Sunset	County Code 079		0.945 *b*	1.00 *b*	3.544	3.461	5.088	5.728	4.541	7.419
Millar Gas	Field	Field total			0.164	0.077	0.048	0.047	0.034	0.000
Millar Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Millar Gas	Main Area				0.025	0.001	0.041	0.047	0.034	0.000
Millar Gas	West Area				0.139	0.076	0.007	0.000	0.000	0.000
Monroe Swell	Field	Field total			2.282	2.670	2.233	1.204	1.381	1.148
Monroe Swell	Field	Not matched to pool/*OQ*	0.930 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Monroe Swell	Northwest Area		0.916 *c*		1.255	1.502	1.142	0.524	0.901	0.516
Monroe Swell	Old Area		0.944 *c*		1.027	1.168	1.091	0.680	0.480	0.632
Montalvo West	Field	Field total			49.978	46.838	44.459	40.082	64.931	91.323
Montalvo West	Field	Not matched to pool/*OQ*	0.923 *c*	4.10 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Montalvo West	Offshore	Sespe	0.922 *c*	4.10 *c*	3.805	3.923	3.422	4.796	3.947	3.684
Montalvo West	Offshore	Colonia	0.959 *d*	4.10 *d*	11.691	10.088	7.505	5.678	19.146	17.569
Montalvo West	Onshore	No breakdown by pool	0.923 *c*	4.10 *c*	34.483	32.663	33.533	29.607	30.307	30.132
Montalvo West	Onshore	Gas Zone	0.923 *c*	4.10 *c*	0.000	0.164	0.000	0.000	0.000	0.000
Montalvo West	Onshore	Sespe	0.887 *c*	4.10 *c*	0.000	0.000	0.000	0.000	11.531	20.995
Montalvo West	Onshore	Colonia	0.959 *c*	4.10 *c*	0.000	0.000	0.000	0.000	0.000	18.943
Montebello	Field	Field total			138.173	128.467	122.178	112.687	110.810	117.459
Montebello	Field	Not matched to pool/*OQ*	0.914 *b*	0.91 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Montebello	Any Area		0.914 *b*	0.91 *b*	38.310	33.344	35.102	34.708	32.477	34.788
Montebello	Main Area	No breakdown by pool	0.914 *b*	0.91 *b*	86.152	78.914	71.433	64.732	64.201	67.310

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Montebello	Main Area	1st and 2nd	0.919 *c*	1.17 *b*	5.265	4.685	3.781	3.482	1.535	1.696
Montebello	West Area	No breakdown by pool	0.914 *b*	0.91 *b*	0.000	0.000	0.000	0.006	0.115	0.225
Montebello	West Area	1st	0.934 *c*	1.17 *b*	0.000	0.000	0.000	0.063	0.000	0.183
Montebello	West Area	Observation Pool	0.914 *b*	0.91 *b*	0.978	0.000	11.862	0.000	4.663	4.360
Montebello	West Area	8th	0.850 *c*	0.91 *b*	7.468	11.523	0.000	9.696	7.819	8.897
Monument Junction	Field	Field total			25.981	23.598	21.572	21.666	21.044	17.123
Monument Junction	Field	Not matched to pool/*OQ*	0.898 *c*		0.000	0.000	0.000	0.000	0.000	1.461
Monument Junction	Main Area	San Joaquin	0.898 *c*		0.000	0.000	0.000	0.000	0.008	0.000
Monument Junction	Main Area	Reef Ridge	0.898 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Monument Junction	Main Area	Antelope	0.898 *c*		21.957	18.486	16.890	17.690	17.837	15.997
Monument Junction	Mongoose Area	Antelope	0.898 *c*		4.024	5.113	4.682	3.976	3.199	2.586
Moorpark West	Field	Field total			0.262	0.287	0.070	0.288	0.292	0.275
Moorpark West	Field	Not matched to pool/*OQ*	0.973 *c*		0.262	0.287	0.070	0.288	0.292	0.275
Morales Canyon	Field	Field total			0.546	0.395	0.490	0.176	0.597	0.372
Morales Canyon	Field	Not matched to pool/*OQ*	0.850 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Morales Canyon	Clayton Area	Clayton	0.865 *c*		0.546	0.395	0.490	0.093	0.234	0.284
Morales Canyon	Government 18	Covernment 18	0.835 *c*		0.000	0.000	0.000	0.083	0.363	0.088
Mount Poso	Field	Field total			111.179	93.159	88.095	89.413	94.248	87.004
Mount Poso	Field	Not matched to pool/*OQ*	0.965 *c*	0.67 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Mount Poso	Baker-Grover	Vedder	0.963 *c*	0.67 *b*	0.942	1.487	1.495	2.220	2.575	2.103
Mount Poso	Dominion Area	Pyramid Hill	0.979 *c*	0.67 *b*	0.189	0.235	0.136	0.020	0.019	0.045
Mount Poso	Dominion Area	Vedder	0.966 *c*	0.67 *b*	14.429	13.247	14.818	14.187	14.804	15.831
Mount Poso	Dorsey Area	Vedder	0.963 *c*	0.68 *c*	7.924	8.496	7.828	7.963	7.970	7.455
Mount Poso	Granite Canyon	Vedder	0.966 *c*	0.67 *b*	1.772	1.963	1.941	1.801	1.440	1.351
Mount Poso	Main Area	No breakdown by pool	0.964 *c*	0.65 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Mount Poso	Main Area	Pyramid Hill	0.966 *c*	0.65 *c*	0.000	1.481	2.364	3.098	8.527	15.351
Mount Poso	Main Area	Pyramid Hill-Vedder	0.964 *c*	0.65 *c*	84.263	65.555	59.050	59.512	57.794	42.276
Mount Poso	Main Area	Vedder	0.963 *c*	0.67 *b*	0.170	0.043	0.051	0.338	1.049	2.353
Mount Poso	West Area	Vedder	0.959 *c*	0.67 *b*	1.491	0.652	0.412	0.273	0.070	0.235
Mountain View	Field	Field total			28.850	25.917	23.018	23.724	25.010	21.928
Mountain View	Field	Not matched to pool/*OQ*	0.874 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Arvin Area		0.873 *c*	0.36 *c*	1.295	1.178	1.050	1.087	1.625	1.405
Mountain View	Arvin West Area	Richards	0.863 *c*	0.44 *b*	0.869	0.949	1.219	1.308	1.311	1.119
Mountain View	Arvin West Area	Chanac-Cattani	0.871 *c*	0.51 *c*	0.240	0.192	0.099	0.152	0.288	0.191
Mountain View	Arvin West Area	Cattani	0.876 *c*	0.44 *b*	0.994	0.976	0.955	0.972	1.024	1.015
Mountain View	Arvin West Area	Houchin Main	0.850 *c*	0.44 *b*	0.287	0.265	0.202	0.178	0.161	0.161

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Mountain View	Arvin West Area	Houchin Northwest & Brite	0.850	*c*	0.44	*b*	4.639	4.008	3.381	3.415	3.149	2.842
Mountain View	Arvin West Area	Stenderup	0.887	*c*	0.44	*b*	1.694	1.748	1.495	1.581	1.736	1.560
Mountain View	Arvin West Area	Frick	0.893	*c*	0.44	*b*	1.265	1.337	1.521	1.480	1.572	1.240
Mountain View	Digiorgio Area	No breakdown by pool	0.879	*c*	0.44	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Digiorgio Area	Schist	0.898	*c*	0.44	*b*	0.000	0.000	0.000	1.103	0.560	0.002
Mountain View	Main Area	No breakdown by pool	0.882	*c*	0.44	*b*	17.237	14.963	12.749	11.814	13.366	12.204
Mountain View	Main Area	Kern River-Chanac	0.911	*c*	0.36	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Vaccaro Area	Chanac	0.845	*c*	0.51	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Vaccaro Area	Upper Miocene	0.858	*c*	0.44	*b*	0.329	0.301	0.348	0.634	0.219	0.188
Newhall	Field	Field total					0.260	0.237	0.276	0.338	0.228	0.267
Newhall	Field	Not matched to pool/*OQ*	0.918	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	De Witt Canyon	Kraft	0.928	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Elsmere Area		0.966	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Pico Canyon Area		0.852	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Rice Canyon Area		0.888	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Townsite Area		0.934	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Towsley Canyon		0.935	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Tunnel Area		0.954	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Whitney Canyon		0.920	*c*			0.260	0.237	0.276	0.338	0.228	0.250
Newhall	Wiley Canyon		0.888	*c*			0.000	0.000	0.000	0.000	0.000	0.017
Newhall-Potrero	Field	Field total					28.584	32.927	34.651	30.558	27.727	22.335
Newhall-Potrero	Field	Not matched to pool/*OQ*	0.864	*b*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	1.620
Newhall-Potrero		No breakdown by pool	0.864	*b*	0.60	*b*	0.000	0.000	0.000	0.000	0.142	0.084
Newhall-Potrero		Pico Sands	0.864	*b*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		1-2-3 pool	0.853	*c*	0.52	*c*	12.402	16.974	13.876	10.755	10.357	9.806
Newhall-Potrero		3 pool	0.850	*c*	0.52	*c*	0.866	1.846	1.253	0.793	0.669	0.618
Newhall-Potrero		5th	0.857	*c*	0.56	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		5th/6th	0.851	*c*	0.56	*c*	10.918	9.417	12.119	11.630	11.269	9.199
Newhall-Potrero		6th	0.846	*c*	0.56	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		7th	0.868	*c*	0.81	*b*	4.397	4.689	7.404	7.374	5.290	4.200
Newhall-Potrero		9th	0.864	*b*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Field	Field total					17.018	15.415	15.849	17.880	18.547	16.865
Newport West	Field	Not matched to pool/*OQ*	0.946	*b*	2.74	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Offshore	Division D-E	0.940	*c*	2.74	*b*	5.328	5.457	5.280	4.782	4.968	4.642
Newport West	Onshore	Bolsa	0.947	*c*	2.74	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Onshore	A	0.916	*c*	1.99	*b*	1.369	1.297	1.472	1.552	1.402	1.257

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Newport West	Onshore	B	0.947 *c*	1.99 *b*	7.836	6.568	6.055	6.129	5.444	4.887
Newport West	Onshore	C	0.916 *c*	2.74 *b*	2.473	2.074	3.043	5.416	6.733	6.078
Newport West	Onshore	D	0.916 *c*	2.74 *b*	0.010	0.019	0.000	0.000	0.000	0.000
Oak Canyon	Field	Field total			6.270	6.537	6.133	5.109	5.058	5.031
Oak Canyon	Field	Not matched to pool/*OQ*	0.887 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		1-A	0.910 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		3-AB	0.876 *c*	1.03 *c*	0.000	0.000	0.000	0.000	0.000	0.223
Oak Canyon		3-ABCD	0.893 *c*	1.03 *c*	3.237	3.417	3.066	2.510	2.607	2.363
Oak Canyon		3-CD	0.910 *c*	1.03 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		4-AB	0.876 *c*	0.59 *b*	0.460	0.456	0.408	0.375	0.347	0.368
Oak Canyon		4-AB & 5-A	0.873 *c*	0.59 *b*	0.575	0.580	0.589	0.386	0.141	0.000
Oak Canyon		6-AB, 7, and 8-AB	0.871 *c*	0.59 *b*	1.998	2.084	2.070	1.838	1.963	2.077
Oak Park	Field	Field total			4.270	2.956	3.638	3.095	2.939	2.748
Oak Park	Field	Not matched to pool/*OQ*	0.922 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oak Park		Sespe	0.922 *c*		4.270	2.956	3.638	3.095	2.939	2.748
Oakridge	Field	Field total			11.779	7.903	11.611	12.425	11.560	10.260
Oakridge	Field	Not matched to pool/*OQ*	0.928 *c*	0.98 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oakridge		Miocene	0.928 *c*	0.98 *b*	11.779	7.903	11.611	12.425	11.560	10.260
Oat Mountain	Field	Field total			6.385	5.415	9.094	11.369	12.595	19.382
Oat Mountain	Field	Not matched to pool/*OQ*	0.948 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oat Mountain		Pliocene	0.948 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oat Mountain		Sesnon-Eocene	0.948 *c*		6.385	5.415	9.094	11.369	12.595	19.382
Oil Creek	Field	Field total			0.459	0.373	0.297	0.170	0.101	0.193
Oil Creek	Field	Not matched to pool/*OQ*	0.820 *c*		0.459	0.373	0.297	0.170	0.101	0.193
Ojai	Field	Field total			52.527	47.341	46.451	45.786	41.782	43.316
Ojai	Field	Not matched to pool/*OQ*	0.921 *c*	1.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Lion Mountain	Lower Sespe	0.920 *c*	1.63 *b*	0.411	0.314	0.402	0.500	0.157	0.428
Ojai	Lion Mountain	Eocene	0.893 *c*	1.63 *b*	0.265	0.201	0.241	0.260	0.082	0.224
Ojai	N. Sulphur Mtn.	Miocene	0.917 *c*	1.63 *b*	10.697	9.571	8.722	7.619	8.751	10.158
Ojai	Oakview Area		0.865 *c*	1.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Silverthread Area	Pliocene	0.922 *c*	1.63 *b*	0.063	0.055	0.058	0.054	0.065	0.066
Ojai	Silverthread Area	Miocene	0.893 *c*	1.63 *b*	30.931	26.927	26.980	28.514	24.463	24.177
Ojai	Sisar Creek Area	Saugus	0.973 *c*	1.63 *b*	1.994	1.818	1.830	1.861	1.727	1.703
Ojai	Sisar Creek Area	Saugus-Miocene	0.973 *c*	1.63 *b*	0.220	0.385	0.341	0.356	0.375	0.374
Ojai	Sisar Creek Area	Miocene	0.973 *c*	1.63 *b*	0.638	0.435	0.433	0.461	0.415	0.728
Ojai	Sulphur Crest	Miocene	0.892 *c*	1.63 *b*	6.693	6.878	6.530	5.306	4.896	5.095

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Ojai	Sulphur Mountain	Miocene	0.953	*c*	1.63	*b*	0.545	0.713	0.754	0.703	0.699	0.423
Ojai	Tip Top Area		0.916	*c*	1.63	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Weldon Canyon		0.882	*c*	1.63	*b*	0.070	0.044	0.159	0.206	0.153	0.257
Olive	Field	Field total					3.303	3.374	3.167	3.171	3.177	3.113
Olive	Field	Not matched to pool/*OQ*	0.973	*c*			3.303	3.374	3.167	3.171	3.177	3.113
Orcutt	Field	Field total					92.217	94.897	101.422	106.258	138.418	175.231
Orcutt	Field	Not matched to pool/*OQ*	0.880	*c*	2.48	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Monterey	0.919	*c*	2.17	*c*	0.121	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Pt Sal	0.882	*c*	0.61	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Lospe	0.863	*c*	1.65	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Main Area	No breakdown by pool	0.880	*c*	2.48	*b*	91.354	93.450	98.890	104.716	127.504	137.253
Orcutt	Main Area	Diatomite	0.880	*c*	2.48	*b*	0.742	1.447	2.533	1.542	10.914	30.730
Orcutt	Main Area	SX	0.880	*c*	2.48	*b*	0.000	0.000	0.000	0.000	0.000	20.131
Orcutt	Main Area	Monterey Deep	0.855	*c*	2.48	*b*	0.000	0.000	0.000	0.000	0.000	1.517
Oxnard	Field	Field total					16.933	14.789	12.878	11.115	24.040	19.811
Oxnard	Field	Not matched to pool/*OQ*	1.010	*c*	5.77	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		Pliocene Tar	1.022	*c*	6.00	*c*	15.610	14.061	11.850	9.737	22.544	18.176
Oxnard		Miocene Tar	1.022	*c*	7.54	*b*	0.000	0.016	0.041	0.041	0.041	0.037
Oxnard		Topanga	0.910	*c*	1.72	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		McInnes	0.910	*c*	1.72	*b*	1.324	0.712	0.986	1.337	1.454	1.597
Oxnard		Lucas	0.865	*c*	1.72	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		Livingston and E-D	0.857	*c*	1.72	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Pacoima	Field	Field total					0.000	1.488	0.830	0.307	0.000	0.000
Pacoima	Field	Not matched to pool/*OQ*	0.855	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Pacoima		Modelo Gas Zone	0.855	*c*			0.000	0.153	0.198	0.000	0.000	0.000
Pacoima		Modelo	0.855	*c*			0.000	1.335	0.632	0.307	0.000	0.000
Paloma	Field	Field total					3.811	4.448	5.421	5.148	4.695	4.312
Paloma	Field	Not matched to pool/*OQ*	0.806	*b*	0.26	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Gas Zone	0.806	*b*	0.26	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Paloma	0.804	*c*	0.40	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Antelope	0.806	*b*	0.26	*b*	0.000	0.000	0.047	0.290	0.123	0.158
Paloma	Main Area	Lower Stevens	0.819	*c*	0.10	*c*	3.304	3.914	4.776	4.052	3.961	3.610
Paloma	Symons Area	Symons	0.792	*c*	0.10	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Symons Area	Paloma	0.816	*c*	0.40	*c*	0.507	0.534	0.598	0.805	0.611	0.544
Pescado Offshore	Field	Field total					835.129	794.985	807.051	702.007	770.829	717.512
Pescado Offshore	Field	Not matched to pool/*OQ*	0.917	*f*			835.129	794.985	807.051	702.007	770.829	717.512

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Pioneer	Field	Field total					0.286	0.308	0.387	0.394	0.351	0.366
Pioneer	Field	Not matched to pool/*OQ*	0.825	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Pioneer		Miocene	0.825	*c*			0.286	0.308	0.387	0.394	0.351	0.366
Pitas Point Offshore	Field	Field total					0.117	0.000	0.000	0.059	0.112	0.059
Pitas Point Offshore	Field	Not matched to pool/*OQ*	0.835	*e*	0.61	*e*	0.117	0.000	0.000	0.059	0.112	0.059
Placerita	Field	Field total					196.527	172.576	162.715	152.629	134.848	114.907
Placerita	Field	Not matched to pool/*OQ*	0.927	*b*	1.30	*b*	196.527	0.000	0.000	0.000	134.848	0.000
Placerita		No breakdown by pool	0.927	*b*	1.30	*b*	0.000	172.576	162.715	152.629	0.000	18.667
Placerita		Upper Kraft	0.986	*c*	1.30	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Placerita		Lower Kraft	0.925	*c*	1.30	*b*	0.000	0.000	0.000	0.000	0.000	96.240
Playa Del Rey	Field	Field total					6.641	5.623	7.144	6.106	7.822	7.497
Playa Del Rey	Field	Not matched to pool/*OQ*	0.907	*b*	2.65	*b*	0.000	0.000	0.000	0.000	0.000	0.363
Playa Del Rey	Del Rey Hills Area		0.907	*b*	3.20	*c*	0.783	0.649	1.424	1.443	1.378	0.822
Playa Del Rey	Kidson Area		0.876	*c*	2.65	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Playa Del Rey	Venice Area		0.924	*c*	2.65	*b*	5.859	4.974	5.720	4.663	6.444	6.700
Pleasant Valley	Field	Field total					0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley	Field	Not matched to pool/*OQ*	0.866	*c*	0.35	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Temblor	0.850	*c*	0.35	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Kreyenhagen	0.866	*c*	0.35	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Gatchell	0.882	*c*	0.35	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleito	Field	Field total					36.092	32.269	30.230	29.978	43.034	39.634
Pleito	Field	Not matched to pool/*OQ*	0.935	*c*	1.18	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleito	Creek Area		0.953	*c*	1.18	*c*	2.197	2.279	2.002	1.988	11.106	14.054
Pleito	Ranch Area		0.916	*c*	1.18	*c*	33.895	29.990	28.228	27.990	31.928	25.580
Point Arguello OCS	Field	Field total					576.230	453.842	414.619	426.343	388.670	366.854
Point Arguello OCS	Field	Not matched to pool/*OQ*	0.934	*c*	2.90	*c*	576.230	453.842	414.619	426.343	388.670	366.854
Pt. Pedernales OCS	Field	Field total					379.534	404.059	472.821	440.090	426.093	364.590
Pt. Pedernales OCS	Field	Not matched to pool/*OQ*	0.960	*c*	1.40	*e*	379.534	404.059	472.821	440.090	426.093	364.590
Poso Creek	Field	Field total					45.343	75.121	114.511	206.274	320.456	356.434
Poso Creek	Field	Not matched to pool/*OQ*	0.979	*c*	0.94	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Poso Creek	Enas Area		0.983	*c*	0.98	*c*	1.125	1.493	1.057	1.395	2.645	2.041
Poso Creek	McVan Area		0.973	*c*	0.80	*c*	12.682	34.283	62.896	131.810	207.814	210.001
Poso Creek	Premier Area	No breakdown by pool	0.978	*c*	0.98	*c*	31.536	39.345	50.558	73.069	109.931	140.919
Poso Creek	Premier Area	Etchegoin-Chanac	0.981	*c*	0.98	*c*	0.000	0.000	0.000	0.000	0.066	3.429
Pyramid Hills	Field	Field total					10.547	11.282	10.089	10.377	10.652	9.084
Pyramid Hills	Field	Not matched to pool/*OQ*	0.903	*c*			0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Pyramid Hills	Dagany Area	KR	0.959	c			3.861	3.902	3.067	3.320	3.708	3.187
Pyramid Hills	Dagany Area	Canoas	0.804	c			0.039	0.024	0.036	0.041	0.045	0.022
Pyramid Hills	Norris Area	Miocene	0.986	c			0.177	0.226	0.180	0.407	0.232	0.141
Pyramid Hills	Norris Area	Eocene	0.899	c			1.320	2.000	1.661	1.609	1.408	0.681
Pyramid Hills	Orchard Ranch	Canoas	0.814	c			0.000	0.000	0.000	0.000	0.000	0.000
Pyramid Hills	West Area	Gas Zone	0.903	c			0.000	0.000	0.000	0.000	0.000	0.000
Pyramid Hills	West Slope Area	KR	0.953	c			5.150	5.130	5.144	5.000	5.260	5.053
Railroad Gap	Field	Field total					5.975	2.892	2.173	5.545	14.498	23.035
Railroad Gap	Field	Not matched to pool/*OQ*	0.867	c	0.86	b	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		No breakdown by pool	0.867	c	0.86	b	0.000	0.000	0.000	0.038	0.839	2.729
Railroad Gap		Gas Zone	0.867	c	0.86	b	0.136	0.104	0.069	0.707	0.466	0.638
Railroad Gap		Amnicola	0.979	c	1.60	b	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		Olig	0.816	c	0.67	c	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		Antelope Shale	0.867	b	2.00	c	2.206	1.690	1.059	3.742	6.935	6.737
Railroad Gap		Antelope Shale/Carneros	0.867	c	0.86	b	0.000	0.000	0.000	0.000	0.000	0.503
Railroad Gap		Valv	0.866	c	0.64	c	0.000	0.136	0.124	0.080	0.176	0.331
Railroad Gap		Carneros	0.857	b	0.44	b	0.213	0.105	0.117	0.226	5.447	11.499
Railroad Gap		Phacoides	0.810	c	0.22	b	3.421	0.857	0.804	0.751	0.635	0.597
Raisin City	Field	Field total					22.096	21.648	29.737	33.951	29.059	29.161
Raisin City	Field	Not matched to pool/*OQ*	0.906	b	0.43	b	0.000	0.000	0.000	0.000	0.000	0.000
Raisin City		Zilch	0.897	c	0.70	c	19.856	17.398	15.523	16.320	16.136	18.098
Raisin City		Eocene	0.888	c	0.41	c	2.240	4.251	14.214	17.433	12.923	11.063
Raisin City		Moreno	0.906	b	0.43	b	0.000	0.000	0.000	0.198	0.000	0.000
Raisin City		Panoche	0.906	b	0.43	b	0.000	0.000	0.000	0.000	0.000	0.000
Ramona	Field	Field total					11.443	10.820	12.257	11.956	12.092	11.430
Ramona	Field	Not matched to pool/*OQ*	0.911	b	2.45	b	11.443	10.820	12.257	11.956	12.092	11.430
Ramona North	Field	Field total					0.028	0.000	0.000	0.020	0.055	0.104
Ramona North	Field	Not matched to pool/*OQ*	0.947	c			0.028	0.000	0.000	0.020	0.055	0.104
Richfield	Field	Field total					68.862	63.458	59.648	56.549	54.999	60.205
Richfield	Field	Not matched to pool/*OQ*	0.946	c	1.56	c	68.862	63.458	59.648	56.549	54.999	60.205
Rincon	Field	Field total					76.299	59.580	60.614	63.305	54.573	51.790
Rincon	Field	Not matched to pool/*OQ*	0.873	c	0.70	b,c	0.000	0.000	0.000	0.000	0.000	0.000
Rincon	Offshore		0.865	c	0.20	c	16.591	7.408	7.189	4.869	2.413	1.852
Rincon	Onshore		0.880	c	1.20	b	59.708	52.172	53.426	58.436	52.160	46.282
Rio Bravo	Field	Field total					26.751	27.674	29.116	27.838	29.858	30.102
Rio Bravo	Field	Not matched to pool/*OQ*	0.849	c	0.29	b	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Rio Bravo		No breakdown by pool	0.849	*c*	0.29	*b*	0.000	0.000	0.000	0.010	0.022	2.672
Rio Bravo		Gas Zone	0.849	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		Round Mountain	0.849	*c*	0.29	*b*	0.000	0.129	0.174	0.177	0.194	0.183
Rio Bravo		Olcese	0.860	*c*	0.29	*b*	5.866	1.327	1.831	1.821	2.490	2.741
Rio Bravo		Round Mt-Olcese	0.849	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		R. Brvo-Mn Vedder-Osborn	0.838	*c*	0.35	*c*	20.885	26.218	27.111	25.830	27.153	24.506
Rio Bravo		Osborn-Helbling	0.849	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		Helbling	0.850	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Viejo	Field	Field total					15.632	15.142	14.273	13.869	13.221	12.189
Rio Viejo	Field	Not matched to pool/*OQ*	0.879	*c*	0.90	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Viejo		Stevens	0.879	*c*	0.90	*c*	15.632	15.142	14.273	13.869	13.221	12.189
Rio Vista Gas	Field	Field total					2.348	2.481	2.742	4.412	4.928	2.210
Rio Vista Gas	Field	Not matched to pool/*OQ*					2.348	2.481	2.742	4.412	4.928	2.210
River Island Gas	Field	Field total					0.000	0.182	0.539	0.189	0.100	0.073
River Island Gas	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		No breakdown by pool					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Markley-Nortonville					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Nortonville					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Domengine-Capay					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Mokulumne River					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Starkey					0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Winters					0.000	0.182	0.539	0.189	0.100	0.073
Riverdale	Field	Field total					4.617	5.907	6.286	5.628	6.032	14.486
Riverdale	Field	Not matched to pool/*OQ*	0.832	*b*	0.25	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Riverdale		Miocene	0.825	*b*	0.22	*b*	2.814	3.947	4.596	3.671	3.841	8.826
Riverdale		Eocene	0.839	*b*	0.27	*b*	1.803	1.960	1.690	1.956	2.192	5.613
Rocky Point Offshore	Field	Field total					24.235	125.927	113.716	50.316	29.825	0.000
Rocky Point Offshore	Field	Not matched to pool/*OQ*					24.235	125.927	113.716	50.316	29.825	0.000
Rose	Field	Field total					39.785	46.649	40.802	37.673	34.009	29.466
Rose	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Rose		McClure					39.785	46.649	40.802	37.673	34.009	29.466
Rosecrans	Field	Field total					29.175	30.476	29.771	29.732	27.545	27.829
Rosecrans	Field	Not matched to pool/*OQ*	0.838	*b*	0.54	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Rosecrans	Main Area		0.838	*b*	0.54	*b*	27.910	28.617	27.778	27.448	25.236	25.624
Rosecrans	Athens Area		0.838	*b*	0.54	*b*	0.000	0.532	0.836	1.012	1.109	1.060
Rosecrans	Central Area		0.838	*b*	0.54	*b*	1.265	1.327	1.157	1.272	1.199	1.145

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Rosecrans East	Field	Field total			0.423	0.281	0.269	0.273	0.231	0.007
Rosecrans East	Field	Not matched to pool/*OQ*	0.876 *c*	0.52 *b*	0.423	0.281	0.269	0.273	0.231	0.007
Rosecrans South	Field	Field total			2.365	2.371	2.312	2.072	1.983	1.826
Rosecrans South	Field	Not matched to pool/*OQ*	0.857 *c*	0.52 *b*	2.365	2.371	2.312	2.072	1.983	1.826
Rosedale	Field	Field total			4.351	4.159	3.840	3.206	3.234	2.851
Rosedale	Field	Not matched to pool/*OQ*	0.873 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	East Area	Stevens	0.887 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	Main Area	Stevens	0.870 *c*	0.75 *c*	4.243	3.917	3.630	3.031	3.077	2.676
Rosedale	North Area	Stevens	0.871 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	South Area	Stevens	0.865 *c*	0.75 *c*	0.107	0.242	0.210	0.175	0.157	0.175
Rosedale Ranch	Field	Field total			16.283	16.480	18.188	26.072	29.861	31.335
Rosedale Ranch	Field	Not matched to pool/*OQ*	0.934 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Rosedale Ranch	Main Area	Etchegoin	0.966 *c*		2.441	2.056	1.037	2.312	2.825	3.290
Rosedale Ranch	Main Area	Lerdo-Chanac	0.932 *c*		12.817	13.344	16.277	17.078	18.215	16.584
Rosedale Ranch	Main Area	Chanac	0.922 *c*		0.000	0.000	0.000	5.892	8.108	11.035
Rosedale Ranch	Northeast Area	Lerdo-Chanac	0.934 *c*		0.615	0.647	0.525	0.474	0.370	0.137
Rosedale Ranch	Northeast Area	Chanac	0.917 *c*		0.410	0.431	0.350	0.316	0.343	0.290
Round Mountain	Field	Field total			205.980	251.643	222.346	214.102	219.044	304.064
Round Mountain	Field	Not matched to pool/*OQ*	0.956 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	4.036
Round Mountain	Alma Area	Vedder	0.979 *c*	0.60 *b*	0.000	0.072	0.046	0.144	0.198	0.210
Round Mountain	Coffee Canyon	Pyramid Hill	0.943 *c*	0.59 *b*	0.399	0.454	0.446	0.290	0.315	0.384
Round Mountain	Coffee Canyon	Pyramid Hill-Vedder	0.956 *c*	0.71 *c*	6.031	6.073	7.946	7.386	6.685	5.890
Round Mountain	Main Area	No breakdown by pool	0.943 *c*	0.49 *c*	0.000	0.474	8.631	19.596	20.961	10.784
Round Mountain	Main Area	Jewett-Vedder	0.943 *c*	0.54 *b*	198.829	243.861	194.472	163.863	173.850	230.360
Round Mountain	Main Area	Vedder	0.959 *c*	0.60 *b*	0.000	0.000	1.857	5.686	3.943	6.892
Round Mountain	Main Area	Pyramid Hill	0.947 *c*	0.43 *c*	0.000	0.000	8.231	16.505	12.253	44.840
Round Mountain	Pyramid Hill	Vedder	0.959 *c*	0.60 *b*	0.721	0.710	0.636	0.626	0.742	0.710
Round Mountain	Sharktooth Area	Vedder	0.979 *c*	0.60 *b*	0.000	0.000	0.082	0.005	0.097	0.017
Russell Ranch	Field	Field total			7.048	8.636	10.559	10.958	10.592	10.718
Russell Ranch	Field	Not matched to pool/*OQ*	0.778 *c*	0.31 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Russell Ranch	Main Area		0.726 *c*	0.36 *c*	6.953	8.544	10.502	10.956	10.451	10.716
Russell Ranch	Southeast Area	Dibblee	0.830 *c*	0.29 *b*	0.095	0.092	0.057	0.002	0.141	0.002
Ryer Island Gas	Field	Field total			0.055	0.018	0.018	0.105	0.068	0.090
Ryer Island Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Ryer Island Gas	Offshore				0.000	0.000	0.000	0.000	0.000	0.000
Ryer Island Gas	Onshore				0.055	0.018	0.018	0.105	0.068	0.090

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Sacate Offshore	Field	Field total			470.309	598.889	654.297	612.861	501.797	475.563
Sacate Offshore	Field	Not matched to pool/*OQ*	0.868 *c*		470.309	598.889	654.297	612.861	501.797	475.563
Salt Lake	Field	Field total			17.538	9.032	7.933	8.851	8.221	7.886
Salt Lake	Field	Not matched to pool/*OQ*	0.954 *c*	2.73 *b*	17.538	9.032	7.933	8.851	8.221	7.886
Salt Lake South	Field	Field total			8.688	8.474	8.739	7.203	5.401	5.642
Salt Lake South	Field	Not matched to pool/*OQ*	0.910 *c*		8.688	8.474	8.739	7.203	5.401	5.642
San Ardo	Field	Field total			634.214	558.932	500.897	546.406	662.852	838.089
San Ardo	Field	Not matched to pool/*OQ*	0.985 *b*	2.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
San Ardo	Main Area	Lombardi	0.985 *b*	2.14 *b*	572.288	496.403	447.748	483.180	583.547	763.518
San Ardo	Main Area	Auriguac	0.985 *b*	2.25 *b*	61.926	62.530	52.977	51.027	43.023	55.308
San Ardo	North Area	Lombardi	0.990 *c*	2.37 *c*	0.000	0.000	0.172	12.200	36.282	19.263
San Emidio Nose	Field	Field total			5.987	5.327	4.643	5.148	4.376	3.058
San Emidio Nose	Field	Not matched to pool/*OQ*	0.866 *c*	0.93 *b*	0.000	0.000	0.000	0.000	0.000	0.000
San Emidio Nose	Main Area	Reef Ridge	0.868 *c*	0.83 *c*	0.000	0.000	0.000	0.000	0.000	0.000
San Emidio Nose	Main Area	Stevens	0.865 *c*	0.93 *b*	4.455	3.947	3.307	3.808	3.310	2.916
San Emidio Nose	Northwest Area	Stevens	0.863 *c*	0.93 *b*	1.532	1.380	1.336	1.341	1.066	0.142
San Joaquin	Field	Field total			0.569	0.508	0.555	0.476	0.543	0.578
San Joaquin	Field	Not matched to pool/*OQ*	0.876 *c*		0.000	0.000	0.000	0.000	0.000	0.000
San Joaquin		Eocene	0.876 *c*		0.569	0.508	0.555	0.476	0.543	0.578
San Miguelito	Field	Field total			101.467	87.233	79.298	89.552	87.439	106.832
San Miguelito	Field	Not matched to pool/*OQ*	0.876 *c*	0.90 *b*	101.467	87.233	0.000	0.000	0.000	0.000
San Miguelito		Grubb 1-3	0.871 *c*	0.87 *c*	0.000	0.000	10.072	25.301	40.036	57.045
San Miguelito		Grubb 4-5	0.888 *c*	0.90 *b*	0.000	0.000	43.121	41.983	39.550	41.871
San Miguelito		Grubb D	0.871 *c*	0.87 *c*	0.000	0.000	1.165	7.728	7.852	7.916
San Vicente	Field	Field total			109.898	93.731	76.938	67.028	63.297	57.065
San Vicente	Field	Not matched to pool/*OQ*	0.912 *c*		0.000	0.000	0.000	0.000	0.000	0.000
San Vicente		Clifton, Dayton and Hay	0.912 *c*		109.898	93.731	76.938	67.028	63.297	57.065
Sansinena	Field	Field total			43.991	42.390	45.511	44.600	41.504	29.622
Sansinena	Field	Not matched to pool/*OQ*	0.925 *c*	0.87 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	12-G Area		0.949 *c*	0.87 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	Central Area		0.905 *c*	0.87 *b*	2.863	3.482	3.916	3.989	4.135	3.755
Sansinena	Curtis Area		0.925 *c*	0.87 *b*	1.508	0.929	0.736	0.269	0.367	0.408
Sansinena	East Area		0.897 *c*	0.87 *b*	13.343	11.719	12.694	11.617	11.014	7.814
Sansinena	New England Area		0.932 *c*	0.87 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	West Area		0.940 *c*	0.87 *b*	26.277	26.261	28.165	28.725	25.988	17.646
Santa Clara Avenue	Field	Field total			11.258	10.644	10.691	11.276	11.604	12.201

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Santa Clara Avenue	Field	Not matched to pool/*OQ*	0.914 *c*	2.00 *c*	11.258	10.644	10.691	11.276	11.604	12.201
Santa Clara Offshore	Field	Field total			108.134	92.569	96.149	85.175	95.437	98.940
Santa Clara Offshore	Field	Not matched to pool/*OQ*	0.887 *c*	2.85 *e*	108.134	92.569	96.149	85.175	95.437	98.940
Santa Fe Springs	Field	Field total			98.086	113.841	108.169	101.717	102.800	100.605
Santa Fe Springs	Field	Not matched to pool/*OQ*	0.861 *b*	0.41 *b*	98.086	113.841	108.169	101.717	102.800	100.605
Santa Maria Valley	Field	Field total			31.291	23.323	20.581	19.320	13.833	20.823
Santa Maria Valley	Field	Not matched to pool/*OQ*	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Bradley Area	Foxen	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Bradley Area	Basal Sisquoc	0.973 *c*	4.13 *c*	6.843	2.969	2.476	3.298	1.511	5.276
Santa Maria Valley	Bradley Area	Monterey	0.973 *c*	4.35 *b*	1.236	0.699	1.214	1.031	0.083	0.744
Santa Maria Valley	Clark Area	Foxen	1.000 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Clark Area	Sisquoc	1.011 *c*	4.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Clark Area	Clark	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Main Area		0.965 *c*	3.00 *c*	7.980	9.062	7.902	5.912	8.720	7.112
Santa Maria Valley	North Area	Foxen	0.979 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Foxen	1.000 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Sisquoc	0.990 *c*	4.35 *b*	10.036	5.598	4.001	4.679	0.592	3.035
Santa Maria Valley	Southeast Area	Houk	0.990 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Monterey	1.014 *c*	4.35 *b*	1.730	1.818	1.826	1.362	0.000	1.510
Santa Maria Valley	West Area		0.964 *c*	0.60 *c*	3.466	3.177	3.162	3.037	2.926	2.939
Santa Susana	Field	Field total			5.646	3.556	4.525	4.349	3.612	3.107
Santa Susana	Field	Not matched to pool/*OQ*	0.821 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Santa Susana		Sespe	0.821 *c*		0.979	0.642	0.652	0.943	0.786	0.882
Santa Susana		First Sespe	0.806 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Santa Susana		Second and Third Sespe	0.835 *c*		4.668	2.914	3.873	3.406	2.826	2.225
Sargent	Field	Field total			3.285	2.848	2.954	3.825	4.486	4.007
Sargent	Field	Not matched to pool/*OQ*	0.952 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sargent		No breakdown by pool	0.952 *b*	0.86 *b*	3.285	2.848	2.954	3.032	2.571	2.473
Sargent		Purisma Sand	0.932 *c*	0.62 *c*	0.000	0.000	0.000	0.792	1.915	1.534
Saticoy	Field	Field total			7.596	7.182	8.792	8.326	7.076	6.566
Saticoy	Field	Not matched to pool/*OQ*	0.854 *c*	0.94 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Saticoy	Main Area		0.854 *c*	0.94 *b*	7.029	6.990	8.284	7.741	6.597	5.937
Saticoy	South Area		0.854 *c*	0.94 *b*	0.568	0.192	0.508	0.586	0.479	0.629
Sawtelle	Field	Field total			38.476	33.490	33.706	29.285	28.826	28.695
Sawtelle	Field	Not matched to pool/*OQ*	0.902 *b*	1.99 *b*	38.476	33.490	33.706	29.285	28.826	28.695
Seal Beach	Field	Field total			74.059	70.371	76.528	77.406	78.039	74.269

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific		Sulfur		Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity		% wt.		2004	2005	2006	2007	2008	2009
Seal Beach	Field	Not matched to pool/*OQ*	0.867	*b*	0.55	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	Alamitos Area		0.886	*c*	0.55	*b*	4.439	4.324	4.068	4.406	3.873	6.394
Seal Beach	Marine Area	Wasem	0.888	*c*	0.55	*b*	0.197	0.472	0.331	0.432	0.405	0.268
Seal Beach	Marine Area	McGrath	0.904	*c*	0.55	*b*	6.223	6.196	7.177	7.425	7.402	6.676
Seal Beach	North Block	No breakdown by pool	0.898	*c*	0.55	*b*	31.606	30.164	31.712	32.274	33.351	31.777
Seal Beach	North Block	Selover	0.893	*c*	0.55	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	N. Block-East Ext.	Recent	0.867	*b*	0.55	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	N. Block-East Ext.	Wasem	0.887	*c*	0.55	*b*	1.775	1.500	1.419	1.371	1.447	1.401
Seal Beach	N. Block-East Ext.	McGrath	0.877	*c*	0.55	*b*	2.048	2.159	1.954	1.897	2.161	2.048
Seal Beach	South Block		0.896	*c*	1.00	*c*	27.770	25.557	29.867	29.590	29.401	28.241
Semitropic	Field	Field total					6.478	6.442	6.175	5.660	5.896	4.797
Semitropic	Field	Not matched to pool/*OQ*	0.846	*c*			0.000	0.000	0.000	0.000	0.000	0.438
Semitropic		Gas Zone	0.846	*c*			0.022	0.045	0.181	0.000	0.043	0.128
Semitropic		Randolph	0.876	*c*			6.456	6.397	5.994	5.660	5.853	5.120
Semitropic		Vedder	0.816	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Field	Field total					71.285	61.951	62.307	61.906	62.563	54.681
Sespe	Field	Not matched to pool/*OQ*	0.887	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Foot of the Hills	Middle Sespe	0.934	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Foot of the Hills	Basal Sespe	0.910	*c*			1.322	1.018	1.206	1.080	1.151	0.448
Sespe	Foot of the Hills	Eocene	0.910	*c*			0.052	0.054	0.056	0.052	0.057	0.049
Sespe	Little Sespe Creek	Upper Sespe	0.887	*c*			1.150	0.745	0.698	0.654	0.499	0.135
Sespe	Little Sespe Creek	Basal Sespe	0.871	*c*			0.644	0.667	0.729	0.720	0.731	0.570
Sespe	Tar Crk-Topatopa	No breakdown by pool	0.875	*c*			4.600	3.189	4.393	4.218	4.391	5.485
Sespe	Tar Crk-Topatopa	Rincon-Vaqueros	0.865	*c*			0.163	0.078	0.276	0.633	0.575	0.223
Sespe	Tar Crk-Topatopa	Vaqueros	0.865	*c*			0.922	1.116	1.008	1.185	1.221	1.346
Sespe	Tar Crk-Topatopa	Upper Sespe	0.887	*c*			1.676	1.288	1.225	1.076	0.717	0.931
Sespe	Tar Crk-Topatopa	Middle Sespe	0.887	*c*			2.015	2.034	2.205	1.745	1.319	1.227
Sespe	Tar Crk-Topatopa	Basal Sespe	0.871	*c*			56.577	49.781	48.420	48.362	49.174	42.028
Sespe	Tar Crk-Topatopa	Coldwater	0.876	*c*			2.164	1.981	2.091	2.180	2.729	2.236
Shafter North	Field	Field total					122.413	113.215	103.849	103.572	107.392	91.598
Shafter North	Field	Not matched to pool/*OQ*	0.890	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Shafter North		McClure	0.890	*c*			122.413	113.215	103.849	103.572	107.392	91.598
Shiells Canyon	Field	Field total					9.511	10.536	10.608	10.747	13.778	12.902
Shiells Canyon	Field	Not matched to pool/*OQ*	0.866	*c*	0.78	*c*	9.511	0.000	0.000	0.000	13.778	5.125
Shiells Canyon	Main Area	No breakdown by pool	0.866	*c*	0.78	*c*	0.000	10.536	10.608	10.747	0.000	0.670
Shiells Canyon	Main Area	Sespe	0.865	*c*	0.78	*c*	0.000	0.000	0.000	0.000	0.000	0.960

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Shiells Canyon	Main Area	Eocene	0.860 *c*	0.78 *c*	0.000	0.000	0.000	0.000	0.000	6.147
Simi	Field	Field total			0.069	0.122	0.132	0.146	0.123	0.114
Simi	Field	Not matched to pool/*OQ*	0.900 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Old Area	No breakdown by pool	0.882 *c*	0.68 *b*	0.069	0.122	0.132	0.146	0.123	0.114
Simi	Old Area	Gas Zone	0.900 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Old Area	Llajas	0.876 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Strathearn Area		0.860 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Canada da la Brea		0.948 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Alamos Canyon		0.931 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sockeye Offshore	Field	Field total			270.434	278.630	234.778	245.710	239.933	243.032
Sockeye Offshore	Field	Not matched to pool/*OQ*	0.917 *c*	3.26 *e*	270.434	278.630	234.778	245.710	239.933	243.032
South Mountain	Field	Field total			79.072	74.778	74.022	71.815	72.153	76.341
South Mountain	Field	Not matched to pool/*OQ*	0.886 *b*	1.73 *b*	79.072	74.778	74.022	71.815	72.153	76.341
Stockdale	Field	Field total			14.895	16.045	15.150	15.203	15.381	15.514
Stockdale	Field	Not matched to pool/*OQ*	0.893 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Stockdale	Old Area	Chanac	0.898 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Stockdale	Panama Lane	Nozu	0.887 *c*		14.895	16.045	15.150	15.203	15.381	15.514
Strand	Field	Field total			1.127	0.715	0.648	0.647	0.622	0.785
Strand	Field	Not matched to pool/*OQ*	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	East Area	Stevens	0.855 *c*	0.41 *c*	0.418	0.067	0.000	0.000	0.000	0.264
Strand	Main Area	Gas Zone	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Upper Stevens	0.850 *c*	0.43 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Lower Stevens	0.860 *c*	0.45 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Vedder	0.835 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Northwest Area	Gas Zone	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Northwest Area	Stevens	0.857 *c*	0.54 *c*	0.709	0.648	0.648	0.647	0.622	0.521
Strand	South Area	Stevens	0.871 *c*	0.43 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Suisun Bay Gas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Suisun Bay Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Tapia	Field	Field total			1.863	6.186	8.391	7.641	9.042	9.108
Tapia	Field	Not matched to pool/*OQ*	0.953 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapia		No breakdown by pool	0.953 *c*		1.863	6.186	8.391	7.641	9.042	9.108
Tapia		Saugus	0.953 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapo Canyon South	Field	Field total			1.992	1.799	2.374	2.375	2.117	1.773
Tapo Canyon South	Field	Not matched to pool/*OQ*	0.926 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapo Canyon South		No breakdown by pool	0.926 *c*		1.636	1.427	1.908	1.950	1.712	1.354

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Tapo Canyon South		Sespe	0.947 *c*		0.356	0.372	0.467	0.426	0.405	0.418
Tapo North	Field	Field total			0.072	0.148	1.023	0.931	1.029	0.940
Tapo North	Field	Not matched to pool/*OQ*	0.930 *c*		0.072	0.148	1.023	0.931	1.029	0.940
Tapo Ridge	Field	Field total			0.465	0.379	0.557	0.535	0.451	0.316
Tapo Ridge	Field	Not matched to pool/*OQ*	0.956 *c*		0.465	0.379	0.557	0.535	0.451	0.316
Tejon	Field	Field total			53.970	53.910	48.997	54.131	93.381	84.936
Tejon	Field	Not matched to pool/*OQ*	0.879 *b*	0.27 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon	Central Area		0.879 *b*	0.28 *c*	7.095	9.593	9.124	12.926	11.118	9.129
Tejon	Eastern Area		0.947 *c*	0.27 *b*	2.658	2.566	2.428	1.935	2.449	2.369
Tejon	Southeast Area		0.943 *c*	0.27 *b*	2.988	3.143	2.881	3.000	2.834	2.675
Tejon	Western Area		0.944 *c*	0.40 *c*	41.229	38.608	34.563	36.270	76.979	70.763
Tejon Hills	Field	Field total			2.434	1.767	1.950	1.945	1.671	2.241
Tejon Hills	Field	Not matched to pool/*OQ*	0.866 *b*	0.26 *b*	2.434	1.767	1.950	1.945	1.671	2.241
Tejon North	Field	Field total			9.579	10.009	9.313	8.882	7.395	6.739
Tejon North	Field	Not matched to pool/*OQ*	0.846 *b*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		No breakdown by pool	0.846 *b*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Fruitvale	0.917 *c*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Olcese	0.845 *c*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Olcese-Eocene	0.811 *c*	0.20 *c*	3.468	3.844	3.056	3.076	2.803	2.547
Tejon North		JV-Basalt	0.797 *c*	0.16 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Vedder-Eocene	0.810 *c*	0.24 *c*	6.111	6.165	6.257	5.805	4.592	4.191
Temblor Ranch	Field	Field total			0.221	0.141	0.138	0.064	0.033	0.023
Temblor Ranch	Field	Not matched to pool/*OQ*	0.959 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Temblor Ranch		Miocene	0.959 *c*		0.221	0.141	0.138	0.064	0.033	0.023
Temescal	Field	Field total			4.834	5.118	5.337	5.348	4.819	3.891
Temescal	Field	Not matched to pool/*OQ*	0.920 *b*	0.55 *b*	4.834	5.118	5.337	5.348	4.819	3.891
Ten Section	Field	Field total			19.630	18.551	18.466	19.041	14.455	14.692
Ten Section	Field	Not matched to pool/*OQ*	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Main Area	Gas Zone	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Main Area	Upper Stevens	0.845 *c*	0.41 *b*	17.533	17.205	17.120	17.423	12.811	13.159
Ten Section	Main Area	Lower Stevens	0.860 *c*	0.41 *b*	2.098	1.346	1.346	1.617	1.644	1.533
Ten Section	Northwest Area	No breakdown by pool	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Northwest Area	Stevens	0.852 *c*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Thornton WWG Gas	Field	Field total			0.000	0.000	0.038	0.153	0.014	0.000
Thornton WWG Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.038	0.153	0.014	0.000
Timber Canyon	Field	Field total			6.187	3.250	6.000	5.497	4.888	6.278

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Timber Canyon	Field	Not matched to pool/*OQ*	0.847 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Timber Canyon	Loel-Maxwell Area		0.840 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Timber Canyon	Main Area		0.855 *c*		6.187	3.250	6.000	5.497	4.888	6.278
Tisdale Gas	Field	Field total			0.000	0.000	0.000	0.000	0.008	0.000
Tisdale Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Tisdale Gas	Main Area	Forbes			0.000	0.000	0.000	0.000	0.008	0.000
Tisdale Gas	Southeast Area	Forbes			0.000	0.000	0.000	0.000	0.000	0.000
Tisdale Gas	Southeast Area	Guinda			0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Field	Field total			60.768	58.047	61.020	61.287	61.560	59.173
Torrance	Field	Not matched to pool/*OQ*	0.934 *b*	2.26 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Offshore	Del Amo	0.887 *c*	2.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Offshore	Others	0.930 *c*	2.43 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Onshore	Tar-Ranger & Main, East	0.936 *c*	1.37 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Onshore	Others	0.934 *b*	2.26 *b*	57.219	54.931	57.893	58.047	58.323	55.642
Torrance	Onshore	Del Amo	0.887 *c*	2.42 *b*	3.549	3.116	3.127	3.240	3.237	3.531
Torrey Canyon	Field	Field total			13.830	10.938	14.342	14.046	13.976	12.720
Torrey Canyon	Field	Not matched to pool/*OQ*	0.896 *c*	2.74 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrey Canyon		Sespe	0.896 *c*	2.74 *b*	1.686	1.417	1.757	1.691	1.664	1.621
Torrey Canyon		First Sespe	0.910 *c*	2.74 *b*	0.828	0.626	0.871	0.876	0.733	0.526
Torrey Canyon		Second Sespe	0.882 *c*	2.74 *b*	0.836	0.727	1.007	0.935	0.945	0.873
Torrey Canyon		Third Sespe	0.896 *c*	2.74 *c*	1.172	1.187	1.452	1.479	1.343	1.333
Torrey Canyon		Deep	0.896 *c*	2.74 *b*	9.308	6.982	9.255	9.065	9.291	8.367
Tulare Lake	Field	Field total			2.518	0.391	0.000	0.000	0.000	0.000
Tulare Lake	Field	Not matched to pool/*OQ*	0.843 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		Salyer	0.771 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		KCDC	0.826 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		54-8U	0.865 *c*		1.521	0.283	0.000	0.000	0.000	0.000
Tulare Lake		54-8M	0.850 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		54-8L	0.865 *c*		0.507	0.094	0.000	0.000	0.000	0.000
Tulare Lake		Boswell	0.876 *c*		0.490	0.015	0.000	0.000	0.000	0.000
Tulare Lake		Vaqueros	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Union Avenue	Field	Field total			0.812	1.077	0.848	0.600	0.888	2.902
Union Avenue	Field	Not matched to pool/*OQ*	0.966 *c*	2.25 *c*	0.812	1.077	0.848	0.600	0.888	2.902
Union Station	Field	Field total			2.358	0.651	0.225	0.000	0.000	0.000
Union Station	Field	Not matched to pool/*OQ*	0.829 *c*		2.358	0.651	0.225	0.000	0.000	0.000
Vallecitos	Field	Field total			1.159	1.161	0.857	0.829	0.825	1.161

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Vallecitos	Field	Not matched to pool/*OQ*	0.877 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Ashurst Area	Domengine-Yokut	0.900 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Cedar Flat Area	San Carlos	0.921 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Central Area	Ashurst	0.840 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Central Area	Domengine-Yokut	0.850 *c*		0.699	0.716	0.585	0.567	0.653	0.755
Vallecitos	Franco Area	Yokut	0.860 *c*		0.195	0.244	0.215	0.232	0.056	0.247
Vallecitos	Griswold Canyon	San Carlos	0.845 *c*		0.035	0.021	0.035	0.028	0.031	0.028
Vallecitos	Los Pinos Canyon		0.898 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Silver Creek Area	San Carlos	0.904 *c*		0.230	0.179	0.022	0.003	0.085	0.132
Vallecitos	Pimental Cn. Gas	Yokut	0.877 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Valpredo	Field	Field total			0.000	0.000	0.000	0.006	0.003	0.000
Valpredo	Field	Not matched to pool/*OQ*	0.898 *c*	1.80 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Valpredo		Miocene	0.898 *c*	1.80 *c*	0.000	0.000	0.000	0.006	0.003	0.000
Van Ness Slough	Field	Field total			0.398	0.199	0.176	0.131	0.071	0.020
Van Ness Slough	Field	Not matched to pool/*OQ*	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Van Ness Slough		Miocene	0.845 *c*		0.398	0.199	0.176	0.131	0.071	0.020
Van Sickle Island Gas	Field	Field total			0.000	0.000	0.120	0.350	1.297	1.254
Van Sickle Island Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.120	0.350	1.297	1.254
Ventura	Field	Field total			697.753	627.288	675.084	671.198	664.385	666.861
Ventura	Field	Not matched to pool/*OQ*	0.866 *b*	1.08 *b*	697.753	627.288	675.084	671.198	664.385	666.861
Walnut	Field	Field total			1.688	1.554	1.347	1.391	1.304	1.277
Walnut	Field	Not matched to pool/*OQ*	0.959 *c*		1.688	1.554	1.347	1.391	1.304	1.277
Wasco	Field	Field total			0.083	0.049	0.000	0.000	0.000	0.006
Wasco	Field	Not matched to pool/*OQ*	0.836 *c*	0.21 *b*	0.083	0.049	0.000	0.000	0.000	0.006
Wayside Canyon	Field	Field total			2.874	2.959	2.728	2.639	1.978	1.457
Wayside Canyon	Field	Not matched to pool/*OQ*	0.925 *c*		2.874	2.959	2.728	2.639	1.978	1.457
West Mountain	Field	Field total			1.560	1.621	1.610	1.533	1.268	1.169
West Mountain	Field	Not matched to pool/*OQ*	0.934 *c*		1.560	1.621	1.610	1.533	1.268	1.169
Wheeler Ridge	Field	Field total			16.243	15.655	15.391	16.355	12.306	11.231
Wheeler Ridge	Field	Not matched to pool/*OQ*	0.884 *b*	0.46 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	No breakdown by pool	0.884 *b*	0.46 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Coal Oil Canyon	0.916 *c*	0.69 *c*	1.690	1.417	1.787	1.581	1.186	0.473
Wheeler Ridge	Central Area	Coal Oil Canyon-Main	0.896 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Miocene-Oligocene	0.852 *c*	0.55 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Main	0.876 *c*	0.69 *c*	0.698	0.633	0.616	0.750	1.526	0.887
Wheeler Ridge	Central Area	Valv	0.898 *c*	0.40 *c*	0.763	0.427	0.247	0.288	0.065	0.113

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Wheeler Ridge	Central Area	2-38 pool	0.825	*c*	0.40	*c*	0.311	0.351	0.475	0.483	0.493	0.551
Wheeler Ridge	Central Area	Olcese	0.825	*c*	0.40	*b*	0.284	0.232	0.236	0.460	0.919	0.517
Wheeler Ridge	Central Area	Oligocene-Eocene	0.827	*c*	0.46	*b*	0.536	0.479	0.523	0.400	0.173	0.080
Wheeler Ridge	Central Area	ZA-5	0.806	*c*	0.46	*b*	0.000	0.000	0.000	0.045	0.283	0.134
Wheeler Ridge	Central Area	ZB-3	0.884	*b*	0.46	*b*	0.771	0.636	0.377	0.329	0.190	0.199
Wheeler Ridge	Central Area	ZB-5	0.806	*c*	0.46	*b*	0.810	0.710	0.668	0.564	0.437	0.459
Wheeler Ridge	Central Area	Refugian Eocene	0.847	*c*	0.29	*c*	4.224	5.508	5.403	6.270	2.911	4.342
Wheeler Ridge	Northeast Area	FA-2	0.947	*c*	0.69	*b*	0.880	1.010	1.046	0.852	0.716	0.973
Wheeler Ridge	Northeast Area	Hagood	0.953	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Northeast Area	ZB-1	0.830	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Northeast Area	Vedder	0.830	*c*	0.46	*b*	1.552	1.197	0.915	1.267	0.732	0.348
Wheeler Ridge	Southeast Area	Olcese	0.811	*c*	0.46	*b*	0.037	0.049	0.684	0.991	1.206	0.516
Wheeler Ridge	Telegraph Canyon	Eocene	0.780	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Windgap Area	No breakdown by pool	0.826	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Windgap Area	Reserve	0.928	*c*	0.69	*b*	3.688	3.005	2.413	2.072	1.466	1.676
Wheeler Ridge	Windgap Area	Olcese	0.724	*c*	0.40	*b*	0.000	0.000	0.000	0.000	0.000	0.000
White Wolf	Field	Field total					0.814	0.744	0.863	1.650	2.553	2.252
White Wolf	Field	Not matched to pool/*OQ*	0.968	*c*			0.814	0.744	0.863	1.650	2.553	2.252
Whittier	Field	Field total					13.743	8.347	9.841	14.217	19.606	17.754
Whittier	Field	Not matched to pool/*OQ*	0.922	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	Upper	0.945	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	6th, 184 Anticline	0.874	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	184 Anticline	0.845	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	La Habra Area		0.931	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Rideout Heights	No breakdown by pool	0.952	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.584	0.454
Whittier	Rideout Heights	Pliocene	0.969	*c*	0.60	*b*	11.565	7.064	8.074	12.863	17.201	15.427
Whittier	Rideout Heights	Miocene	0.936	*c*	0.53	*c*	2.178	1.283	1.767	1.354	1.821	1.873
Wilmington	Field	Field total					2,381.235	2,387.980	2,358.855	2,366.217	2,319.053	2,173.822
Wilmington	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Wilmington	Offshore		0.908	*b,c*	1.54	*b,c*	1,874.608	1,870.824	1,812.232	1,757.379	1,710.736	1,618.035
Wilmington	Onshore		0.914	*b,c*	1.39	*b,c*	506.626	517.156	546.624	608.839	608.317	555.787
Yorba Linda	Field	Field total					10.795	0.000	0.000	0.000	0.000	0.000
Yorba Linda	Field	Not matched to pool/*OQ*	0.963	*c*	1.90	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Shallow	0.979	*c*	1.86	*b*	10.795	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Main	0.966	*c*	1.68	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Shell	0.957	*c*	1.99	*b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Yorba Linda		F Sand	0.957 *c*	1.99 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		E Sand	0.957 *c*	1.99 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Miocene Contact	0.966 *c*	1.90 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yowlumne	Field	Field total			54.905	43.902	37.742	37.305	31.424	26.902
Yowlumne	Field	Not matched to pool/*OQ*	0.865 *c*	0.42 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Yowlumne		Etchegoin	0.865 *c*	0.42 *c*	0.680	0.599	0.419	0.632	0.042	0.489
Yowlumne		Stevens	0.868 *c*	0.60 *c*	54.225	43.303	37.324	36.672	31.382	26.412
Yowlumne		South Yowlumne	0.871 *c*	0.42 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Zaca	Field	Field total			35.787	28.823	24.952	24.608	12.486	31.853
Zaca	Field	Not matched to pool/*OQ*	1.008 *b*	5.65 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Zaca		Monterey North Block	1.008 *b*	5.65 *b*	11.778	9.395	8.658	8.552	4.047	10.975
Zaca		Monterey South Block	1.008 *b*	5.65 *b*	24.009	19.428	16.294	16.055	8.439	20.878
Grand total crude and condensate production reported by Cal. Div. Oil & Gas[a]					**42,567**	**40,685**	**39,649**	**38,686**	**37,956**	**36,583**

[a] *Annual Report of the State Oil & Gas Supervisor, 2004–2008, and Monthly Oil and Gas Production and Injection reports 2009*. Reports PR06; PR04. California Department of Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. Production and reserves.

[b] *California Oil and Gas Fields*. Cal. Dept. Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. 1998. Three volumes. http://www.conservation.ca.gov/dog/pubs_stats/Pages/technical_reports.aspx; accessed 2 June 2011.

[c] *Crude Oil Analysis Database*. U.S. Department of Energy, National Energy Technology Laboratory: Bartlesville OK. Summary of Analyses; www.netl.doe.gov/technologies/oil-gas/Software/database.html; Crude Oil Analysis Database. Accessed 19 May 2011.

[d] *Heavy Oil Database*. U.S. Department of Energy, National Energy Technology Laboratory: Bartlesville OK. Composite of databases; www.netl.doe.gov/technologies/oil-gas/Software/database.html; Heavy Oil Database. Accessed 19 May 2011.

[e] *Oil Properties Database*. Environment Canada: Canada. www.etc-cte.ec.gc.ca/databases/oilproperties. Accessed 13 June 2011.

[f] *Fields/Production History*. County of Santa Barbara Planning and Development, Energy Division: Santa Barbara, CA. http://www.countyofsb.org/energy/projects/exxon.asp; Fields Production/History. Accessed 4 June 2011.

Table 2-5. Facility-level capacity data, California refineries[a]

Barrels/calendar day: (b/cd)

Facility	Year	Atm. dist. (b/cd)	Vacuum dist. (b/cd)	Coking & therm. (b/cd)	Cat. cracking (b/cd)	Hydrocracking (b/cd)
Chevron El Segundo	2008	265,000	147,000	59,000	65,000	46,000
Chevron El Segundo	2009	269,000	147,000	67,500	65,000	46,000
BP Carson	2008	252,225	133,000	63,450	91,800	45,000
BP Carson	2009	252,225	133,000	63,450	92,250	45,000
Chevron Richmond	2008	243,000	110,000	0	80,000	154,250
Chevron Richmond	2009	243,000	110,000	0	80,000	151,000
Tesoro Avon	2008	161,000	144,000	42,000	66,500	32,000
Tesoro Avon	2009	161,000	144,000	42,000	66,500	32,000
Shell Martinez	2008	158,600	91,100	46,500	68,870	37,900
Shell Martinez	2009	145,000	91,100	46,500	68,870	37,900
ExxonMobil Torrance	2008	149,500	98,500	52,500	96,000	20,500
ExxonMobil Torrance	2009	149,500	98,000	52,000	83,500	20,500
Valero Benicia	2008	139,500	78,500	28,000	69,000	36,000
Valero Benicia	2009	139,500	78,500	28,000	69,000	36,000
ConocoPh. Carson & Wilmington[b]	2008	138,700	80,000	48,000	45,000	24,750
ConocoPh. Carson & Wilmington[b]	2009	138,700	80,000	48,000	45,000	24,750
Tesoro Wilmington & Carson[b]	2008	100,000	62,000	40,000	36,000	32,000
Tesoro Wilmington & Carson[b]	2009	100,000	62,000	40,000	36,000	32,000
Ultramar-Valero Wilmington	2008	80,000	46,000	28,000	54,000	0
Ultramar-Valero Wilmington	2009	80,000	46,000	28,000	54,000	0
ConocoPhillips Rodeo[c]	2008	76,000	59,600	25,700	0	37,000
ConocoPhillips Rodeo[c]	2009	76,000	59,600	25,700	0	56,000
Paramount	2008	53,000	33,800	0	0	0
Paramount	2009	88,000	59,800	0	0	0
Big West Bakersfield	2008	65,000	39,000	22,000	0	23,500
Big West Bakersfield	2009	65,000	39,000	22,000	0	23,500
ConocoPhillips Santa Maria[c]	2008	44,200	27,400	21,100	0	0
ConocoPhillips Santa Maria[c]	2009	44,200	27,400	21,100	0	0
Kern Oil & Refining	2008	25,000	0	0	0	0
Kern Oil & Refining	2009	25,000	0	0	0	0
San Joaquin Refining	2008	24,300	14,300	10,000	0	0
San Joaquin Refining	2009	24,300	14,000	10,000	0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14).* Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd) Facility	Year	1º hydrotreating of gas oil, resid. & cracking feeds (b/cd)	2º hydrotreating of hydrocarbon product streams (b/cd)	Reforming (b/cd)	Alkylation (b/cd)	Pol./Dim. (b/cd)
Chevron El Segundo	2008	65,000	136,000	44,000	30,000	0
Chevron El Segundo	2009	65,000	136,000	44,000	30,000	0
BP Carson	2008	85,500	134,730	46,800	13,950	0
BP Carson	2009	85,500	132,030	46,800	15,300	0
Chevron Richmond	2008	0	197,340	69,000	24,000	3,700
Chevron Richmond	2009	0	197,340	69,000	24,000	3,700
Tesoro Avon	2008	62,000	110,500	42,000	14,000	0
Tesoro Avon	2009	62,000	110,500	42,000	14,000	0
Shell Martinez	2008	0	117,950	29,400	11,000	2,470
Shell Martinez	2009	0	117,950	29,400	11,000	2,470
ExxonMobil Torrance	2008	102,000	41,500	19,000	23,500	0
ExxonMobil Torrance	2009	102,000	41,500	19,000	23,500	0
Valero Benicia	2008	37,000	109,000	36,000	17,100	2,900
Valero Benicia	2009	37,000	109,000	36,000	17,100	2,900
ConocoPh. Carson & Wilmington[b]	2008	50,000	85,850	35,200	14,200	0
ConocoPh. Carson & Wilmington[b]	2009	50,000	85,850	35,200	14,200	0
Tesoro Wilmington & Carson[b]	2008	38,000	63,250	32,500	12,000	0
Tesoro Wilmington & Carson[b]	2009	38,000	63,250	32,500	12,000	0
Ultramar-Valero Wilmington	2008	62,500	77,000	17,500	14,500	0
Ultramar-Valero Wilmington	2009	62,500	77,000	17,500	14,500	0
ConocoPhillips Rodeo[c]	2008	0	73,000	31,000	0	0
ConocoPhillips Rodeo[c]	2009	0	73,000	31,000	0	0
Paramount	2008	0	35,250	11,600	0	0
Paramount	2009	0	35,250	11,600	0	0
Big West Bakersfield	2008	21,900	0	14,700	0	0
Big West Bakersfield	2009	0	21,900	14,700	0	0
ConocoPhillips Santa Maria[c]	2008	0	0	0	0	0
ConocoPhillips Santa Maria[c]	2009	0	0	0	0	0
Kern Oil & Refining	2008	0	13,000	3,000	0	0
Kern Oil & Refining	2009	0	13,000	3,000	0	0
San Joaquin Refining	2008	1,800	3,000	0	0	0
San Joaquin Refining	2009	1,800	3,000	0	0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14)*. Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd)

Facility	Year	Aromatics (b/cd)	Isomerization (b/cd)	Lubes (b/cd)	Asphalt (b/cd)	Sulfur (tonnes/d)
Chevron El Segundo	2008	0	27,000	0	0	544
Chevron El Segundo	2009	0	27,000	0	0	544
BP Carson	2008	0	28,170	0	0	446
BP Carson	2009	0	28,193	0	0	446
Chevron Richmond	2008	0	36,600	16,000	0	600
Chevron Richmond	2009	0	36,600	16,000	0	600
Tesoro Avon	2008	0	0	0	0	140
Tesoro Avon	2009	0	0	0	0	140
Shell Martinez	2008	0	15,000	0	15,000	360
Shell Martinez	2009	0	15,000	0	15,000	360.0
ExxonMobil Torrance	2008	0	0	0	0	400
ExxonMobil Torrance	2009	0	0	0	0	380
Valero Benicia	2008	0	0	0	5,000	275
Valero Benicia	2009	0	0	0	5,000	275
ConocoPh. Carson & Wilmington[b]	2008	0	17,500	0	0	340
ConocoPh. Carson & Wilmington[b]	2009	0	17,500	0	0	340
Tesoro Wilmington & Carson[b]	2008	0	8,000	0	0	265
Tesoro Wilmington & Carson[b]	2009	0	8,000	0	0	265
Ultramar-Valero Wilmington	2008	0	10,200	0	0	250
Ultramar-Valero Wilmington	2009	0	10,200	0	0	250
ConocoPhillips Rodeo[c]	2008	0	9,000	0	0	310
ConocoPhillips Rodeo[c]	2009	0	9,000	0	0	472
Paramount	2008	0	3,750	0	16,500	40
Paramount	2009	0	3,750	0	35,000	40
Big West Bakersfield	2008	0	0	0	0	103
Big West Bakersfield	2009	0	0	0	0	103
ConocoPhillips Santa Maria[c]	2008	0	0	0	0	120
ConocoPhillips Santa Maria[c]	2009	0	0	0	0	120
Kern Oil & Refining	2008	0	0	0	0	5
Kern Oil & Refining	2009	0	0	0	0	5
San Joaquin Refining	2008	0	0	4,000	6,500	6
San Joaquin Refining	2009	0	0	4,000	6,500	6

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14).* Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd)

Facility	Year	Total hydrogen excpt. CCR H_2 (MMcfd)	Hydrogen purchased (MMcfd)	Pet. coke production (tonnes/d)
Chevron El Segundo	2008	71.0	146.0	4,064
Chevron El Segundo	2009	71.0	146.0	4,064
BP Carson	2008	133.0	0.0	2,108
BP Carson	2009	133.0	0.0	2,108
Chevron Richmond	2008	170.0	0.0	0
Chevron Richmond	2009	170.0	0.0	0
Tesoro Avon	2008	74.0	31.0	1,500
Tesoro Avon	2009	74.0	31.0	1,500
Shell Martinez	2008	101.0	0.0	1,150
Shell Martinez	2009	101.0	0.0	1,150
ExxonMobil Torrance	2008	160.0	0.0	3,050
ExxonMobil Torrance	2009	160.0	0.0	3,050
Valero Benicia	2008	131.5	0.0	1,080
Valero Benicia	2009	131.5	0.0	1,080
ConocoPh. Carson & Wilmington[b]	2008	100.8	0.0	2,000
ConocoPh. Carson & Wilmington[b]	2009	100.8	0.0	2,000
Tesoro Wilmington & Carson[b]	2008	55.0	55.0	1,615
Tesoro Wilmington & Carson[b]	2009	55.0	55.0	1,615
Ultramar-Valero Wilmington	2008	0.0	50.0	1,700
Ultramar-Valero Wilmington	2009	0.0	50.0	1,700
ConocoPhillips Rodeo[c]	2008	91.0		1,127
ConocoPhillips Rodeo[c]	2009	91.0		1,127
Paramount	2008	0.0	0.0	0
Paramount	2009	0.0	0.0	0
Big West Bakersfield	2008	29.7	0.0	1,200
Big West Bakersfield	2009	29.7	0.0	1,200
ConocoPhillips Santa Maria[c]	2008	0.0	0.0	1,053
ConocoPhillips Santa Maria[c]	2009	0.0	0.0	1,053
Kern Oil & Refining	2008	0.0	0.0	0
Kern Oil & Refining	2009	0.0	0.0	0
San Joaquin Refining	2008	4.2	0.0	0
San Joaquin Refining	2009	4.2	0.0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14).* Data shown are in b/cd.

Table 2-6. Re-assignment of emissions from hydrogen production refiners rely upon from co-located third-party hydrogen plants that are reported separately under California Mandatory GHG Reporting.

		Reported emissions[a]	Reported H_2 purchased[b]	Regional purch. shares		Corrected emissions	
				H_2 cap.[c]	H_2 emit[d]	Mass	Intensity[e]
Fuels refineries	Year	(tonnes)	($m^3 \bullet 10^7$)	(%)	(tonnes)	(tonnes)	(kg/m^3)
S.F. Bay Area							
Chevron Richmond	2008	4,792,052	0.000	0.00	0	4,792,052	339.8
Shell Martinez	2008	4,570,475	0.000	0.00	0	4,570,475	496.6
Valero Benicia	2008	2,796,057	0.000	0.00	0	2,796,057	345.4
Tesoro Avon	2008	2,703,145	32.040	100.00	220,179	2,923,324	312.9
ConocoPhillips Rodeo	2008	1,888,895	0.000	0.00	0	1,888,895	428.3
Chevron Richmond	2009	4,522,383	0.000	0.00	0	4,522,383	320.7
Shell Martinez	2009	4,322,192	0.000	0.00	0	4,322,192	513.7
Valero Benicia	2009	2,889,104	0.000	0.00	0	2,889,104	356.9
Tesoro Avon	2009	2,291,909	32.040	100.00	285,442	2,577,351	275.9
ConocoPhillips Rodeo	2009	1,873,464	0.000	0.00	0	1,873,464	424.8
L.A. Area							
BP Carson	2008	4,504,286	0.000	0.00	0	4,504,286	307.7
Chevron El Segundo	2008	3,603,446	150.900	58.17	1,116,950	4,720,396	307.0
CP Carson & Wilmington	2008	2,924,503	0.000	0.00	0	2,924,503	363.3
ExxonMobil Torrance	2008	2,852,374	0.000	0.00	0	2,852,374	328.8
Tesoro Wilm. & Carson	2008	1,761,136	56.846	21.91	420,770	2,181,906	376.0
Ultramar-Valero Wilm.	2008	951,913	51.678	19.92	382,516	1,334,429	287.4
BP Carson	2009	4,425,697	0.000	0.00	0	4,425,697	302.4
Chevron El Segundo	2009	3,205,873	150.900	58.17	1,061,092	4,266,965	273.3
CP Carson & Wilmington	2009	2,578,050	0.000	0.00	0	2,578,050	320.3
ExxonMobil Torrance	2009	2,694,574	0.000	0.00	0	2,694,574	310.6
Tesoro Wilm. & Carson	2009	1,577,507	56.846	21.91	399,727	1,977,234	340.7
Ultramar-Valero Wilm.	2009	994,536	51.678	19.92	363,387	1,357,923	292.5
Third-party hydrogen plants supplying purchased H_2							
S.F. Bay Area							
Air Products Martinez	2008	220,179					
Air Products Martinez	2009	285,442					
L.A. Area							
Air Products Wilmington	2008	674,672					
Air Liquide El Segundo	2008	667,096					
Air Products Carson	2008	578,468					
Air Products Wilmington	2009	693,003					
Air Liquide El Segundo	2009	540,999					
Air Products Carson	2009	590,204					
Other areas[f]							
Air Products Sacramento	2008	43,168					
Praxair Ontario	2008	41,195					
Air Products Sacramento	2009	45,545					
Praxair Ontario	2009	38,491					

[a] California Mandatory GHG Reporting Rule public facility reports by Cal. Air Resources Board *(2)*.

[b] Third-party hydrogen production capacity, as reported by *Oil & Gas Journal* for each refinery *(6)*.

[c] Percentage share of total third-party hydrogen capacity in the region held by a refinery in a given year.

[d] Emission increment (from "c") of third-party H_2 emissions in region & year added back to refinery emissions.

[e] CO_2 emitted per cubic meter crude refined estimated from atm. distillation capacities in Table 2-5.

[f] Not co-located with refineries: Emissions from "other" H_2 plants are not added to refinery emissions.

Table 2-7. Estimate calculation, 2008 San Francisco Bay Area crude feed quality

	Crude feed component streams			
Parameter, facility or region	Foreign[a]	SJV[b]	ANS[c]	Crude feed[d]
Crude volume (m^3/day)				
Valero Benicia	8,870	5,323	7,986	22,179
Tesoro Avon	9,683	7,935	7,979	25,597
Shell Martinez	4,837	19,920	458	25,215
Chevron Richmond	29,921	0	8,713	38,634
ConocoPhillips Rodeo	1,611	9,183	1,289	12,083
SFBA total	54,922	42,361	26,425	123,708
Crude mass (tonnes/day)				
Valero Benicia	8,108	4,965	6,958	20,031
Tesoro Avon	8,664	7,401	6,953	23,018
Shell Martinez	4,524	18,580	399	23,503
Chevron Richmond	25,566	0	7,592	33,159
ConocoPhillips Rodeo	1,409	8,565	1,123	11,098
SFBA total	48,271	39,511	23,026	110,808
Sulfur mass in crude (tonnes/d)				
Valero Benicia	111	43	77	230
Tesoro Avon	110	64	77	251
Shell Martinez	84	160	4	249
Chevron Richmond	442	0	84	526
ConocoPhillips Rodeo	13	74	12	99
SFBA total	759	340	256	1,355

Estimated crude feed quality (kg/m^3)	density	sulfur
Valero Benicia	903.15	10.39
Tesoro Avon	899.24	9.80
Shell Martinez	932.08	9.86
Chevron Richmond	858.28	13.61
ConocoPhillips Rodeo	918.45	8.22
SFBA total	895.72	10.95

[a] Foreign crude feed volume, density and sulfur content reported for each plant *(14).* in 2008. Density and sulfur are weighted averages for foreign crude processed.

[b] San Joaquin Valley pipeline crude volume based on SJV percentage of refinery feed reported *(27),* and crude charge capacities (Table 2-5). Weighted average density (0.9327 SG) and sulfur (0.861 % wt.) calculated for all crude streams produced in the SJV (Districts 4 and 5) during 2008 from data in Table 2-4.

[c] Alaskan North Slope (ANS) volume estimated by difference of other streams from . charge capacity given in note d. ANS density (0.8714 SG) and sulfur (1.11 % wt.) as reported for the TAPS pipeline terminus at Valdez *(16).*

[d] Crude feed volume from atmospheric distillation charge capacities in Table 2-5. Crude feed mass and mass of sulfur in feed are the sums of component streams. Crude feed density and sulfur content estimates are from data in this column.

Table 2-8. Simplified mixing analysis for potential effects of anomalous oils on average California crude feeds

	Refinery crude feed volume data reported[a]				Anomalous oil assumption[c]		Potential crude feed effect[d]	
	Potentially anomalous streams[b]			Other	Predicted by	Excess in	Crude feed	Crude feed
	Stream 1	Stream 2	Stream 3	streams	density, sulfur	anomalous oil	predicted	with anomaly
Year	(% vol.)	(% vol.)	(% vol.)	(% vol.)	(factor)	(factor)	(factor)	(factor)
2004	29.28	21.68	13.13	35.91	1	2	1.00	1.43
2005	27.16	20.16	14.12	38.57	1	2	1.00	1.41
2006	26.93	16.12	13.27	43.68	1	2	1.00	1.38
2007	26.98	15.79	11.31	45.92	1	2	1.00	1.38
2008	25.72	13.41	12.65	48.21	1	2	1.00	1.36
2009	26.44	15.06	11.29	47.21	1	2	1.00	1.37

PADDs 1-3, 5 range 2003–2008: 1.26–1.40
PADDs 1-3, 5 range 1999–2008: 1.26–1.40

Legend: Density and sulfur content predict unreported characteristics of crude oils more reliably in well-mixed crude feeds than in poorly mixed crude feeds. Anomalies in one oil stream have less potential to affect total feed quality when that stream is mixed with many others of equal or greater volume. This table presents results from a simplified four-component mixing analysis for potential effects of anomalous oils on the crude feeds processed in California each year. It is adapted from recent published work using the same method to validate crude feed quality data among U.S PADDs *(1).*

a. Refinery crude feed component streams represent a foreign country from which California refiners import and process crude *(14),* the Alaska North Slope (ANS) stream, or California-produced crude from either the San Joaquin Valley (Calif. Div. of Oil & Gas districts 4 and 5), California's coastal and offshore reserves (districts 1–3) or northern California (District 6). Stream values are shown as percentages of total crude feed volume *(5).*

b. Potentially anomalous streams might be dominated by oils in which unreported characteristics that affect processing occur in anomalously high amounts *(1).* The streams are ranked based on their volume and the assumption that oils from a single country of origin, region in California, or the ANS, may originate from similar geology and have similar anomalies. Note that this assumption may be overly conservative for purposes other than checking the reliability of predictions based on density and sulfur for these crude feeds.

   Stream 1 in the table represents the San Joaquin Valley, the largest of the streams (as designated above) refined by California refineries in all years. Stream 2 was from the ANS in all years. The third largest stream was from Saudi Arabia during 2004–2008 and from California's coastal region in 2009. Other streams were from 20–26 other countries or regions in California and comprised 36–48% of the crude feed.

c. It was assumed that an unreported charactistic of crude which affects processing was twice as abundant in the anomalous oil as predicted by density and sulfur. This assumption appears plausible as an extreme case *(1).*

Table 2-8 ***continued***
Table legend continued

d. Results estimate the potential for crude feeds to have anomalous high content for unreported characteristics that are not predicted by crude feed density and sulfur. They do not show that any such anomaly actually occurred. Potential effects in the total refinery crude feed assume that the anomalous oil is 100% of stream 1, 50% of stream 2, and 25% of stream 3 for each district and year. This reflects the decreasing likelihood of the same anomaly in multiple separate streams. The predicted factor is assigned to the balance of the streams for each year. Results are show increases from the predicted crude feed factor of 1.00 on the right of Table 2-8.

   Relatively well-mixed crude feeds limit the effect of the anomaly to less than half of its assumed magnitude in the anomalous oil stream. For context, crude sulfur content exceeds that of other process catalyst poisons by eight times in the case of nitrogen and by 160 to 500 times in the cases of nickel and vanadium *(1, 28).* The range of annual estimates for California overlap with those from U.S. PADDs 1, 2, 3 and 5 reported from the original use of this check on crude feed mixing. Those U.S. regions were found to have reasonably well mixed crude feeds for purposes of predicting crude feed quality based on density and sulfur content *(1).* The ranges for PADDs 1, 2, 3 and 5 from that study *(1)* are shown at the bottom right of Table 2-8.

   This check is limited to a simple blending analysis, and the anomalous oil stream assumptions described above. It represents an extreme and unlikely scenario for California given the number of its crude sources and the relatively well-understood refining characteristics of the San Joaquin Valley and ANS streams.

Table 2-9. Preliminary results discarded from the assessment.

[a] Results for annual data among U.S. PADDs 1, 2, 3 and 5 1999–2008 (N = 40) *(1)*.
[b] Subsample including California refining 2004–2009 from Table 2-1 in place of PADD 5 (N =24).
"CA Sub." results potentially unreliable due to small sample size: reported for transparency only.

		R-squared		standardized coefficient of *x*	
y	*x*	U.S.[a]	CA Sub.[b]	U.S.[a]	CA Sub.[b]
energy intensity *(EI)*	crude feed quality *(OQ)*	0.90	0.95		
	density			**0.80**	**0.89**
	sulfur			**0.23**	**0.18**
	refinery capacity utilized			0.05	**−0.18**
	refinery products ratio			−0.10	0.04
energy intensity *(EI)*	crude processing intensity *(PI)*	0.92	0.97		
	vacuum distillation			**0.35**	**0.35**
	conversion capacity			**0.35**	**0.37**
	hydrotreating gas oil & residua			**0.22**	**0.29**
	refinery capacity utilized			**−0.16**	**−0.15**
	refinery products ratio			−0.14	-0.08
crude processing intensity *(PI)*	crude feed quality *(OQ)*	0.94	0.99		
	density			**0.73**	**0.94**
	sulfur			**0.42**	**0.11**
	refinery capacity utilized			**0.09**	0.03
	refinery products ratio			−0.02	**0.09**
hydrogen production capacity	crude feed quality *(OQ)*	0.91	0.97		
	density			**1.09**	**0.96**
	sulfur			−0.01	−0.06
	refinery capacity utilized			0.05	−0.05
	refinery products ratio			**0.35**	**0.27**
sulfur recovery capacity	crude feed quality *(OQ)*	0.94	0.97		
	density			−0.01	**0.44**
	sulfur			**0.95**	**0.71**
	refinery capacity utilized			−0.06	−0.03
	refinery products ratio			**−0.15**	**−0.17**
pet. coke + fuel gas yield	crude feed quality *(OQ)*	0.95	0.98		
	density			**0.80**	**0.83**
	sulfur			**0.34**	**0.30**
	refinery capacity utilized			−0.04	−0.01
gasoline + distillate yield	crude feed quality *(OQ)*	0.75	0.39		
	density			**−0.85**	**−0.37**
	sulfur			−0.07	**−0.38**
	refinery capacity utilized			−0.04	0.03
light liquids/other products ratio	crude feed quality *(OQ)*	0.26	0.05		
	density			**−0.40**	0.05
	sulfur			−0.12	−0.08
	refinery capacity utilized			0.17	0.22
hydrogen production capacity	hydrocracking	0.97	0.97		
	hydrocracking			**1.02**	**1.04**
	refinery capacity utilized			−0.06	0.01
	refinery products ratio			**0.14**	**0.16**
hydrogen production capacity	product stream hydrotreating	0.18	0.37		
	product stream hydrotreating			**−0.33**	**0.49**
	refinery capacity utilized			−0.09	0.03
	refinery products ratio			**−0.17**	−0.19
energy intensity *(EI)*	Yield	0.93	0.92		
	pet. coke + fuel gas yield			**0.59**	**0.81**
	gasoline + distillate yield			**−0.42**	**−0.26**
	refinery capacity utilized			−0.01	−0.11
	refinery products ratio			−0.02	**0.22**
energy intensity *(EI)*	product stream processing	0.91	0.95		
	product stream hydrotreating			**−0.17**	0.08
	reforming			**−0.19**	−0.01
	asphalt			**−0.30**	**−0.29**
	aromatics			**−0.33**	**−0.27**
	polymerization/dimerization			**−0.25**	−0.02
	lubricants			0.04	**0.20**
	alkylation			**0.30**	**0.43**
	isomerization			**0.24**	**0.35**
	refinery capacity utilized			−0.06	−0.10
	refinery products ratio			**-0.33**	−0.08
observed emissions (CO_2)	emissions predicted by oil quality	0.85	0.93		
	EI predicted by crude feed quality			**0.88**	**1.28**
	fuel mix emission intensity			−0.04	0.18

Table 2-10. Energy and emission intensity drivers, nonparametric regressions on all data.

		Observed values (analysis inputs)[a]							
All data		*EI* GJ/m³	FMEI kg/GJ	emit kg/m³	density kg/m³	sulfur kg/m³	cap. util. %	products ratio	1° proc. cap.
PADD 1	1999	3.451	81.53	281.3	858.20	8.24	90.9	3.668	0.972
PADD 1	2000	3.430	80.34	275.6	860.18	8.00	91.7	3.489	0.974
PADD 1	2001	3.518	81.85	288.0	866.34	7.71	87.2	3.479	0.897
PADD 1	2002	3.426	81.08	277.8	865.71	7.45	88.9	3.605	0.944
PADD 1	2003	3.364	81.51	274.2	863.44	7.43	92.7	3.321	0.930
PADD 1	2004	3.416	81.46	278.3	865.44	7.79	90.4	3.397	0.932
PADD 1	2005	3.404	81.23	276.5	863.38	7.17	93.1	3.756	0.936
PADD 1	2006	3.440	80.40	276.5	864.12	7.17	86.7	3.522	0.906
PADD 1	2007	3.499	82.28	287.9	864.33	7.26	85.6	3.443	0.906
PADD 1	2008	3.551	83.26	295.7	863.65	7.08	80.8	3.400	0.906
PADD 2	1999	3.368	78.11	263.1	858.25	10.64	93.3	4.077	1.018
PADD 2	2000	3.361	77.56	260.6	860.03	11.35	94.2	4.132	1.010
PADD 2	2001	3.396	77.46	263.1	861.33	11.37	93.9	4.313	0.988
PADD 2	2002	3.393	77.90	264.3	861.02	11.28	90.0	4.345	1.015
PADD 2	2003	3.298	78.00	257.3	862.80	11.65	91.6	4.281	1.017
PADD 2	2004	3.376	77.25	260.8	865.65	11.86	93.6	4.167	1.035
PADD 2	2005	3.496	77.27	270.2	865.65	11.95	92.9	4.207	1.051
PADD 2	2006	3.738	75.84	283.5	865.44	11.60	92.4	3.907	1.051
PADD 2	2007	3.800	75.55	287.1	864.07	11.84	90.1	4.161	1.017
PADD 2	2008	3.858	74.97	289.3	862.59	11.73	88.4	4.333	1.038
PADD 3	1999	4.546	71.61	325.5	869.00	12.86	94.7	3.120	1.184
PADD 3	2000	4.563	71.87	327.9	870.29	12.97	93.9	3.120	1.213
PADD 3	2001	4.348	72.43	315.0	874.43	14.34	94.8	3.128	1.199
PADD 3	2002	4.434	72.71	322.4	876.70	14.47	91.5	3.251	1.215
PADD 3	2003	4.381	72.81	319.0	874.48	14.43	93.6	3.160	1.232
PADD 3	2004	4.204	73.43	308.7	877.79	14.40	94.1	3.228	1.255
PADD 3	2005	4.205	73.24	308.0	878.01	14.40	88.3	3.316	1.207
PADD 3	2006	4.367	74.15	323.8	875.67	14.36	88.7	3.176	1.203
PADD 3	2007	4.226	74.93	316.7	876.98	14.47	88.7	3.205	1.233
PADD 3	2008	4.361	74.48	324.8	878.66	14.94	83.6	3.229	1.230
PADD 5	1999	4.908	70.27	344.9	894.61	11.09	87.1	2.952	1.275
PADD 5	2000	5.189	69.09	358.5	895.85	10.84	87.5	3.160	1.245
PADD 5	2001	5.039	69.38	349.6	893.76	10.99	89.1	3.231	1.271
PADD 5	2002	4.881	69.15	337.5	889.99	10.86	90.0	3.460	1.315
PADD 5	2003	4.885	69.40	339.0	889.10	10.94	91.3	3.487	1.267
PADD 5	1999	4.908	70.27	344.9	894.61	11.09	87.1	2.952	1.275
PADD 5	2000	5.189	69.09	358.5	895.85	10.84	87.5	3.160	1.245
PADD 5	2001	5.039	69.38	349.6	893.76	10.99	89.1	3.231	1.271
PADD 5	2002	4.881	69.15	337.5	889.99	10.86	90.0	3.460	1.315
PADD 5	2003	4.885	69.40	339.0	889.10	10.94	91.3	3.487	1.267
Calif.	2004	4.994	70.82	353.7	899.23	11.46	93.0	3.631	1.652
Calif.	2005	5.032	71.06	357.5	900.56	11.82	95.0	3.800	1.646
Calif.	2006	5.280	72.65	383.6	899.56	11.73	91.5	3.846	1.665
Calif.	2007	5.611	71.43	400.8	899.84	11.89	88.3	3.814	1.684
Calif.	2008	5.397	71.02	383.3	902.00	12.85	91.0	4.088	1.682
Calif.	2009	5.628	70.54	397.0	901.38	11.70	82.9	4.043	1.676
Calif.	2004	4.994	70.82	353.7	899.23	11.46	93.0	3.631	1.652
Calif.	2005	5.032	71.06	357.5	900.56	11.82	95.0	3.800	1.646
Calif.	2006	5.280	72.65	383.6	899.56	11.73	91.5	3.846	1.665
Calif.	2007	5.611	71.43	400.8	899.84	11.89	88.3	3.814	1.684
Calif.	2008	5.397	71.02	383.3	902.00	12.85	91.0	4.088	1.682
Calif.	2009	5.628	70.54	397.0	901.38	11.70	82.9	4.043	1.676

EI: energy intensity. ***FMEI:*** fuel mix emission intensity. **Pratio:** light liquids/other products ratio. **Primary processing capacity:** the ratio of vacuum distillation, conversion and gas oil/residua hydrotreating to atm. crude distillation capacity.

[a] Data from Table 2-1. 2004–2008 PADD 5 data excluded to avoid errors due to inclusion of Calif. in PADD 5. Calif. data (2004–2009), and PADD 5 data (1999–2003) resampled to balance data counts among regions for regression analyses.

Table 2-10. Energy and emission intensity drivers, nonparametric regressions, continued.

		Predicted *EI* (GJ/m^3) and emissions (kg/m^3) values[b]						Observation vs prediction %Δ					
All data		1 (GJ/m^3)	2 (kg/m^3)	3 (kg/m^3)	4 (kg/m^3)	5 (kg/m^3)	6 (kg/m^3)	1	2	3	4	5	6
PADD 1	1999	3.208	271.5	265.1	265.1	273.9	339.3	8%	4%	6%	6%	3%	-17%
PADD 1	2000	3.316	272.5	270.5	272.8	271.4	321.7	3%	1%	2%	1%	2%	-14%
PADD 1	2001	3.598	286.7	282.6	288.1	275.7	321.6	-2%	0%	2%	0%	4%	-10%
PADD 1	2002	3.532	282.8	283.4	284.1	278.8	339.6	-3%	-2%	-2%	-2%	0%	-18%
PADD 1	2003	3.478	282.6	278.3	281.2	256.7	320.7	-3%	-3%	-1%	-2%	7%	-14%
PADD 1	2004	3.558	285.3	283.0	284.3	274.5	320.9	-4%	-2%	-2%	-2%	1%	-13%
PADD 1	2005	3.132	267.9	277.4	257.4	255.2	334.1	9%	3%	0%	7%	8%	-17%
PADD 1	2006	3.427	276.7	285.6	283.3	284.5	325.9	0%	0%	-3%	-2%	-3%	-15%
PADD 1	2007	3.463	282.9	285.0	284.6	281.9	316.5	1%	2%	1%	1%	2%	-9%
PADD 1	2008	3.540	287.1	295.8	295.8	281.9	349.1	0%	3%	0%	0%	5%	-15%
PADD 2	1999	3.279	266.3	252.8	260.6	275.7	295.2	3%	-1%	4%	1%	-5%	-11%
PADD 2	2000	3.327	267.3	266.0	259.5	273.0	279.2	1%	-3%	-2%	0%	-5%	-7%
PADD 2	2001	3.141	258.5	270.4	248.4	267.7	236.4	8%	2%	-3%	6%	-2%	11%
PADD 2	2002	3.573	277.5	275.8	274.2	285.0	288.6	-5%	-5%	-4%	-4%	-7%	-8%
PADD 2	2003	3.531	276.2	276.3	271.0	280.0	278.6	-7%	-7%	-7%	-5%	-8%	-8%
PADD 2	2004	3.556	275.9	285.7	272.1	279.1	277.0	-5%	-5%	-9%	-4%	-7%	-6%
PADD 2	2005	3.558	275.2	284.1	271.5	283.0	274.7	-2%	-2%	-5%	0%	-5%	-2%
PADD 2	2006	3.777	287.2	279.9	284.4	283.0	327.4	-1%	-1%	1%	0%	0%	-13%
PADD 2	2007	3.716	286.0	278.4	280.9	281.7	319.6	2%	0%	3%	2%	2%	-10%
PADD 2	2008	3.592	282.9	278.0	275.4	297.0	298.6	7%	2%	4%	5%	-3%	-3%
PADD 3	1999	4.516	325.7	293.0	324.3	303.7	314.4	1%	0%	11%	0%	7%	4%
PADD 3	2000	4.534	326.5	297.9	325.0	315.3	313.3	1%	0%	10%	1%	4%	5%
PADD 3	2001	4.403	322.2	326.5	320.1	311.1	319.1	-1%	-2%	-4%	-2%	1%	-1%
PADD 3	2002	4.236	311.7	318.7	312.0	320.5	319.0	5%	3%	1%	3%	1%	1%
PADD 3	2003	4.321	317.4	321.6	315.7	323.1	315.9	1%	1%	-1%	1%	-1%	1%
PADD 3	2004	4.441	324.6	334.3	323.1	334.7	320.1	-5%	-5%	-8%	-4%	-8%	-4%
PADD 3	2005	4.397	321.9	324.6	324.8	331.4	324.1	-4%	-4%	-5%	-5%	-7%	-5%
PADD 3	2006	4.322	314.2	313.6	318.7	326.9	338.0	1%	3%	3%	2%	-1%	-4%
PADD 3	2007	4.343	313.7	317.9	319.5	334.8	335.8	-3%	1%	0%	-1%	-5%	-6%
PADD 3	2008	4.220	307.3	333.6	319.2	340.1	315.7	3%	6%	-3%	2%	-4%	3%
PADD 5	1999	5.001	352.7	359.6	348.1	347.2	361.4	-2%	-2%	-4%	-1%	-1%	-5%
PADD 5	2000	5.125	353.7	359.8	357.0	337.1	331.5	1%	1%	0%	0%	6%	8%
PADD 5	2001	4.973	345.1	351.6	346.4	339.6	330.1	1%	1%	-1%	1%	3%	6%
PADD 5	2002	4.987	346.5	337.8	345.2	350.9	312.1	-2%	-3%	0%	-2%	-4%	8%
PADD 5	2003	4.796	333.9	333.2	333.0	332.2	315.2	2%	2%	2%	2%	2%	8%
Calif.	2004	5.061	359.8	361.5	358.3	368.3	322.6	-1%	-2%	-2%	-1%	-4%	10%
Calif.	2005	4.967	353.1	356.4	355.2	351.7	311.7	1%	1%	0%	1%	2%	15%
Calif.	2006	5.298	389.3	368.6	379.0	376.1	333.3	0%	-1%	4%	1%	2%	15%
Calif.	2007	5.411	386.0	379.7	383.8	394.6	336.2	4%	4%	6%	4%	2%	19%
Calif.	2008	5.422	386.3	394.2	386.6	382.5	311.6	0%	-1%	-3%	-1%	0%	23%
Calif.	2009	5.683	403.2	394.8	401.7	396.5	371.4	-1%	-2%	1%	-1%	0%	7%

Obs–pred %Δ: percent by which observed value exceeds central prediction of nonparametric analysis.

[b] Central predictions from the following analyses:

1 (R^2 0.97): Observed *EI* vs observed crude density, crude sulfur, products ratio and refinery capacity utilization.
2 (R^2 0.96): Observed emit vs *EI* predicted by analysis 1, and observed fuel mix emission intensity (FMEI).
3 (R^2 0.92): Observed emit vs observed crude density, crude sulfur content, and refinery capacity utilization.
4 (R^2 0.96): Observed emit vs observed crude density, crude sulfur, products ratio and refinery capacity utilization.
5 (R^2 0.92): Observed emit vs observed primary processing capacity and refinery capacity utilization.
6 (R^2 0.29): Observed emit vs observed light liquids/other products ratio and refinery capacity utilization.

Attachment 17

Environmental Science & Technology

Policy Analysis

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Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration

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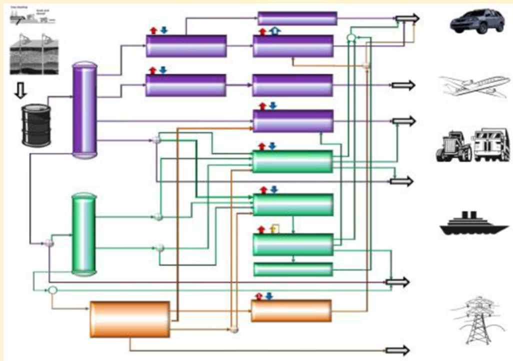
Supporting Information

ABSTRACT: A petroleum refinery model, Petroleum Refinery Life-cycle Inventory Model (PRELIM), which quantifies energy use and greenhouse gas (GHG) emissions with the detail and transparency sufficient to inform policy analysis is developed. PRELIM improves on prior models by representing a more comprehensive range of crude oil quality and refinery configuration, using publicly available information, and supported by refinery operating data and experts' input. The potential use of PRELIM is demonstrated through a scenario analysis to explore the implications of processing crudes of different qualities, with a focus on oil sands products, in different refinery configurations. The variability in GHG emissions estimates resulting from all cases considered in the model application shows differences of up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 g CO_2eq/MJ of diesel (the margin of deviation in the emissions estimates is roughly 10%). This variability is comparable to the magnitude of upstream emissions and therefore has implications for both policy and mitigation of GHG emissions.



INTRODUCTION

The petroleum refining industry is the second-largest stationary emitter of greenhouse gases (GHG) in the U.S.[1] (third-largest in the world[2]). Annual GHG emissions from a large refinery are comparable to the emissions of a typical (i.e., 500 MW) coal-fired power plant.[3,4] For U.S. refineries, where most of the North American production of petroleum-derived fuels occurs, annual emissions were reported to be close to 180 million tonnes of CO_2eq in 2010, representing nearly 12% of U.S. industrial sector emissions or 3% of the total U.S. GHG emissions.[1,5−7]

This industry faces difficult investment decisions due to the shift toward "heavier" crude in the market, both domestic and imported. For example, in 1990, the fraction of imported crude into the U.S. classified as heavy (at or below API gravity, a measure of density, of 20) was roughly 4%. By 2010 this fraction had increased to 15%.[8] Between 2008 and 2015, it is estimated that more than $15 billion will be spent to add processing capacity specifically for heavy crude blends in U.S. refineries.[9] Each refinery must decide whether and how much they will process heavy crude while considering that processing such crudes requires more energy and results in higher refinery GHG emissions. These major capital investment decisions will impact the carbon footprint of the refining industry for decades to come.

Current and future environmental regulations will also affect the decisions faced by this industry. Life cycle assessment (LCA) has been expanded as a tool to enforce GHG emissions policies. For example, California's Low Carbon Fuel Standard[10] (CA-LCFS) embeds life cycle assessment within the policy to measure emissions intensity of various transportation fuel pathways through their full life cycle (including extraction, recovery, and transport). Using LCA in this way requires more accurate assessments of the emissions intensity upstream of the refinery for each crude. However, the varying quality of these crudes will also have significant implications for refinery GHG emissions. Therefore, in this paper we argue that more accurate assessments of the impact of crude qualities on refinery emissions are also required to appropriately account for the variations in emissions and avoid potential unintended consequences from such policies.

The implications for refinery GHG emissions of processing oil sands (OS) products provide a good case study due to the link between upstream processing decisions and refinery emissions, as well as the wide variety of OS products. Canada has the world's third largest petroleum reserves and is the top supplier of imported oil to the U.S.[11] The OS resource represents over 97% of Canada's oil reserves.[12] Current OS operations produce bitumen (an ultraheavy petroleum product) that undergoes either dilution (to produce diluted bitumen referred to as dilbit, synbit, or syndilbit) or upgrading processes

Received: May 11, 2012
Revised: September 11, 2012
Accepted: September 26, 2012

Table 1. Canadian Crudes under Analysis[a]

	Crude Categories	*Production Volumes*	*Configuration selected in Base Case*	*Description*	*S wt%*	*API*	*H wt%*	*MCR wt%*	*~Kw*	*Tb_{50} (°C)*
Bitumen 1	**Bitumen** No bitumen currently goes to refinery. Bitumen case may apply if diluent (condensate) is not used at the refinery.	1.4 M bpd in 2009 including bitumen processed at upgraders[b]	Deep Conversion: Coking and fluid catalytic cracking	Confidential	5.0	8.2	10.1	14.7	11.6	427
Bitumen 2				Confidential	4.1	12.1	10.3	10.9	11.0	442
Dilbit 2	**Diluted bitumen**: (Dilbits) using condensate at a 25:75 % diluents-to-bitumen ratio. Synthetic bitumen blend (Synbit) 50:50 % Light SCO -to-crude ratio. Syndilbit is a bitumen blend with Light SCO and condensate.	Synbit and Syndilbit comprise nearly 2% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Cold Lake (CL):** Asphaltic heavy crude blend of bitumen (11API/5.5%S) and condensate (65API/0.1%S). CL Production ranges from 150 kbd to 200kbd of blend	3.9	20.7	11.2	10.6	11.8	458
Syn-dilbit 1		All diluted bitumens comprise nearly 49% OS production[b]		**Albian Heavy Synthetic** (AHS) contains vacuum residuum (which is an exception for SCOs). It is a blend of sweet SCO crude with unconverted oil from resid hydrocracking	2.2	19.5	10.7	10.9	11.6	447
SCO, So,H1	**Synthetic Crude Oil (SCO)** is a blend of naphtha, distillate, and gas oil range crude fractions. Sweet (Sw) blends comprise majority of SCO production. It has been estimated that 75% of the 2007 SCO production was light Sw SCO without vacuum resid [56]	Nearly 13% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Suncor Synthetic H (OSH)** is a sour synthetic blend. It is comprised of roughly 75% virgin gas oil and 25% lighter fractions.	3.1	19.9	11.1	0.6	11.4	393
SCO, Sw, M1		Nearly 38% OS production[b]	Medium Conversion: fluid catalytic cracking	**Syncrude Synthetic** (SYN) sweet SCO derived from combination of hydroprocessing and fluid coking technologies at upstream upgrading operations. SYN production 58.9 kbd	0.1	31.5	12.5	0.1	11.8	321
SCO, Sw, L1			Hydroskimming	**Husky Synthetic Blend** (HSB) sweet SCO derived from combination of hydroprocessing and delayed coking technologies at upstream upgrading operations. Upgrading production is around 53 kbd	0.1	32.6	12.9	0.1	11.9	329
SCO, Sw, L2				**Suncor Synthetic A (OSA)** sweet SCO. Suncor Upgrading production is around 280 kbd; 60% production is light Sw SCO. i.e., OSA production close to 168kbd	0.2	33.1	12.7	0.02	11.9	315
Conv, So,H1	**Canadian Conventional crude (Conv)**, as oil sands products, are classified based on API (Light API>32, Medium 32>API>22, Heavy API <22) and sulfur content (Sweet S< 0.5wt%, Sour S> 0.5wt%)	6% U.S. Crude oil imports[c]	Deep Conversion: Coking and fluid catalytic cracking	**Bow River North.** Conventional benchmark.	2.7	21.1	11.64	8.57	11.7	427
Conv, So, M1			Medium Conversion: Fluid catalytic cracking	**Midale** (Benchmark medium sour crude)	2.3	29.6	12.1	5.8	11.9	361
Conv, So, L2				**Sour High Edmonton**	1.4	34.9	12.8	3.8	12.8	323
Conv, Sw, L2			Hydroskimming	**Mixed Sweet Blend**	0.4	39.2	13.2	2.0	12.2	298

[a]S: Sulfur content; API: gravity; H: hydrogen content; MCR: micro carbon residuum; ~Kw: approximated Watson characterization factor using Tb_{50} in wt.; Tb_{50}: temperature at which 50% of the mass is recovered through distillation of the whole crude; wt: weight basis; So: sour; Sw: sweet; H: heavy; L: light; kbpd: thousand barrels per day. [b]Calculation basis (2009): 1361 kbpd of oil sands products derived from 1269 kbd of raw bitumen,[57] and 75% of the SCO production ends in sweet light products. [c]Calculation basis (2009): 1269 kbpd U.S crude oil imports from Canada (i.e., 21% of U.S. crude oil imports).[8] 898 kbpd oil sands products exported to U.S. (i.e., 67% of oil sands products[57]); thus, 371 kbpd conventional crude oils exported to U.S. (i.e., 4% of U.S. crude oil imports).

(to produce a high quality synthetic crude oil, SCO) prior to sale to petroleum refineries. Therefore, a diversity of product quality is possible from these operations. Table 1 lists and describes the main characteristics of each category of OS products. The impacts of different OS processing decisions on refinery GHG emissions have the potential to be large and have yet to be explored in depth.

A petroleum refinery is a set of interconnected but distinct process units that convert relatively low value liquid hydrocarbon material (resulting from blending multiple streams of crude feedstock) into more valuable products by increasing its hydrogen to carbon ratio. Different combinations of process units (configurations) are possible leading to a wide variety of potential refinery configurations. In a refinery, a distillation process separates the "whole crude" into groups or "fractions". These fractions are made up of molecules with a particular boiling point temperature range. These ranges are defined by "cut temperatures". Each fraction is then sent to different process units where chemical and thermal processes fragment and/or rearrange the carbon and hydrogen bonds of the hydrocarbon while eliminating the undesired components such as sulfur and nitrogen that are also present in each fraction. Each refinery has a final product specification which dictates the volume and quality of each desired end product (e.g., *X* barrels

dx.doi.org/10.1021/es3018682 | *Environ. Sci. Technol.* XXXX, XXX, XXX−XXX

of gasoline with Y% sulfur). A combination of input crudes is selected and process units are operated to satisfy such specifications.

Crude quality and refinery configuration affect GHG emissions related to processing a particular crude. Crude quality is defined by physical and chemical properties (e.g., the hydrogen content of the crude fractions) that determine the amount and type of processing needed to transform the crude into final products. The technologies employed, as well as how they are combined in operation in a refinery, will require different types and amounts of energy inputs and will produce different types and amounts of energy byproducts (e.g., coke) and final products (e.g., gasoline). For example, heavier crudes generally require more energy to process into final products than lighter crudes due to their need for additional conversion processes and their low hydrogen content.

Two prominent North American life cycle (LC) tools are now forming the basis of regulation as opposed to their original objective of informing policy: Natural Resource Canada's GHGenius[13] and Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET).[14] The GREET model and the CA-GREET version, used as the basis of CA-LCFS, do not account for the effects of crude quality at the refinery stage in their calculations (i.e., all crudes will have the same energy requirements and GHG emissions). GHGenius accounts for crude quality by modifying a default energy intensity value using the average API gravity and sulfur content of an entire refinery crude slate (i.e., a combination of crudes blended as they enter the refinery) and a regression model based on historic regional refinery performance data. [15] The LC models' approaches do not decouple the effects of changes in energy requirements due to changes in crude quality and the changes in each refinery's performance (e.g., process unit efficiencies), nor do they develop a consensus on the impact of allocation (how environmental impacts are split across products in a multiproduct industry).[16] It is possible to combine the use of LC-based models and refinery simulators to calculate LC energy use and GHG emissions for a particular crude and refinery;[17] however, this is not a straightforward effort as will be demonstrated by this paper.

Peer-reviewed analysis that investigates energy and GHG implications of shifting to heavier crudes in refineries has only recently started to appear (since 2010).[18,19] However, these studies did not explore differences in emissions intensity of selected technologies nor investigate the full range of different qualities of crudes derived from the OS operations. Three nonpeer reviewed studies, conducted using a LC framework, have investigated OS crude quality effects on refinery GHG emissions.[17,20−22] However, these studies have used proprietary refinery models limited in the transparency needed to understand the boundaries, assumptions, and data used as well as the ability to evaluate alternate scenarios or pathways.[23] The literature does not present a transparent tool nor recommend a method that predicts GHG emissions with the ability to capture the impact of crude quality and refinery configuration (see Supporting Information (SI) for detailed review of the literature).

This paper (1) provides an overview of the development of the Petroleum Refinery Life-cycle Inventory Model, PRELIM, including model structure and crude assay inventory as well as calculations and assumptions; (2) applies the model to assess the impact of crude quality and refinery configuration on energy use and GHG emissions including a comprehensive set of OS products and conventional crudes; (3) explores the most influential parameters in the model for determining energy use and GHG emissions through scenario analysis; and (4) compares results from previous studies with those from the application of PRELIM.

■ METHOD

PRELIM is a stand-alone, spreadsheet-based model built using a LC approach by employing refinery linear programming modeling methods to represent a range of possible configurations reflecting currently operating refineries in North America. The LC/systems-level approach provides the structure to obtain a tool of wide applicability (i.e., not specific to any one refinery but capable of representing a wide variety of refinery configurations) in the assessment of refinery LC energy use and GHG emissions for crudes of different quality, and allows for the easy incorporation of model results into Well-To-Wheel analyses (WTW). WTWs are a variant of LCAs focused on transportation fuels. The refinery linear programming modeling methods[24] allow for process unit and overall refinery mass balances. These methods overcome the lack of crude specificity of previous LC models[16,25,26] and facilitate exploration of alternative LC inventory allocation methods at the refinery subprocess (i.e., process unit) level. Because the model structure allows for the investigation of two key LCA concepts (i.e., functional unit and allocation[27−29]) as recommended by the International Standard ISO 14041,[30] the model has been called the Petroleum Refinery Life-cycle Inventory Model.

Model Structure and Key Assumptions. Scheme S.1 in the SI presents a basic flow diagram of the overall refinery model structure and how the process units are connected. PRELIM can simulate up to ten specific refinery process configurations. All refinery configurations include crude distillation, hydrotreating, and naphtha catalytic reforming processes. The configurations are differentiated by whether or not the following conversion technologies are present: gas oil hydrocracking, fluid catalytic cracking (referred to hereafter as FCC), delayed coking, and residual hydrocracking. Supporting unit processes such as steam methane reforming (SMR) and acid gas treatment are also included.

Each configuration requires a different amount of energy to process a crude and produces a different slate (i.e., volume and type) of refinery final products including transportation fuels (i.e., gasoline, kerosene, and diesel) as well as heavy fuel oil, hydrogen from the naphtha catalytic reforming process, refinery fuel gas (i.e., gas produced as a byproduct in process units within the refinery), and the possible production of coke or hydrocracking residue. To run the model, a user must select the crude, the configuration, and the allocation method desired through the spreadsheet-based interface. Default values can be used to represent the crude properties and energy requirements of each process unit. Crude properties can be represented by selecting a crude from the crude assay inventory in the model. Alternatively, a user can input a new crude assay and/or can modify any of the process unit model parameters either by selecting a value from the range of parameter values available in the model or by inputting their own parameter value(s). To characterize the whole crude and its fractions, a total of 62 parameters are input to the model, accounting for five crude oil properties: crude distillation curve (i.e., information about mass and volume yields of each fraction, and individual fraction characteristic boiling point), API gravity, sulfur content, hydrogen content, and carbon residue. Supporting information describes how these crude properties affect the refinery energy use and GHG emissions estimates. Two additional crude properties, aromatic content and crude light ends content, impact refinery GHG emissions estimates and are modeled indirectly in PRELIM. PRELIM uses information about the quantity and type of energy required by an individual refinery process unit and assumes that the process energy requirements (electricity, heat, and steam) are linearly related to the process unit's volumetric feed flow rate.[31] This assumption is key to differentiate the energy required to refine crudes with different distillation curves (and therefore different volumes of each fraction that will pass through each process unit). Justification is provided in the SI.

PRELIM calculations include the upstream energy use and GHG emissions associated with the energy sources (i.e., electricity and natural gas).[32] Fugitive GHG emissions from a refinery tend to be an order of magnitude lower than combustion emissions[33] and are not considered in the current version of PRELIM.

The data available in the model for process unit energy requirements are presented as a default as well as a range of plausible values for each parameter derived from the literature.[24,34−37] The data were compared with confidential information and evaluated in consultation with experts from industry to verify that the values and their ranges are appropriate. PRELIM default values for process unit energy requirements are mostly from Gary et al.[35,38]

PRELIM can calculate overall refinery energy use and GHG emissions on a per barrel of crude or per megajoule (MJ) of crude basis, as well as energy use and GHG emissions attributed to a particular final product on a per MJ of product basis (e.g., per MJ of gasoline). For the latter type of functional unit, refinery energy use is allocated to final products at the refinery process unit level (SI details PRELIM allocation procedures, available options in the model, and the implications of different allocation methods). Summing the energy use across all refinery final products on a mass flow rate basis, and comparing to the total energy requirements summed across all process units, verifies the energy balance in the system (all results are reported on a lower heating value basis).

Differences in hydrogen content among crude feedstock and refinery final products are important factors that drive refinery CO_2 emissions.[19] In PRELIM, a global hydrogen mass balance method[39] is used to determine hydrogen requirements for each hydroprocessing unit (hydrotreating and hydrocracking) as well as byproduct hydrogen production from the naphtha catalytic reforming process unit. The method accounts for differences in the hydrogen content of different crudes and the assumption that all crudes are to be processed to meet intermediate and final product hydrogen specifications. Accurately estimating hydrogen requirements is one of the most critical model components (see SI for a more detailed discussion).

PRELIM uses correlations to determine yields of intermediate and final refinery products for each process unit. All correlations used in PRELIM are based on Gary et al.[35] The SI details assumptions about product yields for each process unit.

PRELIM Crude Assay Inventory. The PRELIM crude assay inventory is developed to allow a user the option to select from a predetermined list of crude assays. The current inventory includes publicly available data representing 22 Western Canadian crudes tracked by the Canadian Crude Quality Monitoring Program (CCQMP).[40] Also, the inventory includes seven additional assays from confidential sources to characterize a comprehensive range of qualities for OS-derived products (i.e., bitumen, diluted bitumen, SCO). Currently, there are at least two crude assays representing each category of crude (e.g., bitumen, diluted bitumen, and SCO are all categories of crudes). Western Canadian Conventional crudes are well-characterized using the data available in the public realm. Due to data availability we do not include a full suite of conventional crudes in our analysis. However, preliminary analysis of international crudes shows that the range of emissions presented for Canadian conventional crudes provides a rough approximation of the range of refinery emissions for light crudes globally. However, further analysis is required to confirm this and provide a complete LC comparison.

PRELIM requires characterization of the properties for nine crude fractions (see Scheme S.1). The method of separating the crude into nine fractions is selected to allow the flexibility needed to model different refinery configurations. CCQMP assays must be transformed to obtain the complete set of information needed. The SI details the transformation methods and the results of an evaluation of the methods used. In PRELIM, each particular crude assay is run individually, as opposed to running a crude slate. A crude-by-crude analysis was also suggested and tested in ref 22, and the impact of this simplification on emissions estimates is expected to be small.

Model Evaluation. PRELIM reduces the level of complexity in modeling refinery operations compared to the models used by the industry to optimize their operations. Confidential data (associated with crude assays, operating conditions, and energy requirement estimates) and consultation with refining experts were necessary to assess the validity of PRELIM input data and assumptions. In addition, sensitivity analyses and/or alternative logic calculations to estimate particular parameters were conducted. Finally, a covalidation exercise was conducted by comparing PRELIM's outputs with those of a more detailed refinery model to assess PRELIM's performance, identify any improvements required, and specify the level of accuracy that can be expected when using the model to inform policy.

The covalidation shows that the PRELIM model is capable of replicating the estimates of CO_2 emissions from a more complex model with a reasonable range of error/variability. Overall, the margin of deviation in the emissions estimates due to both assay data quality and the modeling approach is below 10% in almost all cases, which is within the error bounds of typical LC inventories.[41−43] Deviations in energy requirements, which lead to emissions deviations, are mainly associated with estimates for the hydrogen required which is also an uncertain variable in actual refinery operations.[39,44] The deviations are also explained in part by flexibility exhibited by real refinery operating conditions as well as assumptions in modeling. The SI details methods and results of this exercise.

Model Application. A scenario analysis[45] is used to explore the effects that crude quality and refinery configuration have on refinery energy use and GHG emissions estimates.

The starting point for the analysis is a "Base Case Scenario" (referred to hereafter as base case): a set of conditions (e.g., different crudes, emission factors, process unit energy intensities, allocation assumptions) to determine the refinery energy use and GHG emissions of a crude in a "default" refinery configuration. The purpose of the base case is to explore plausible scenarios in which only energy use and GHG emissions associated with the minimum processing capacity needed to transform each crude into transportation fuels or

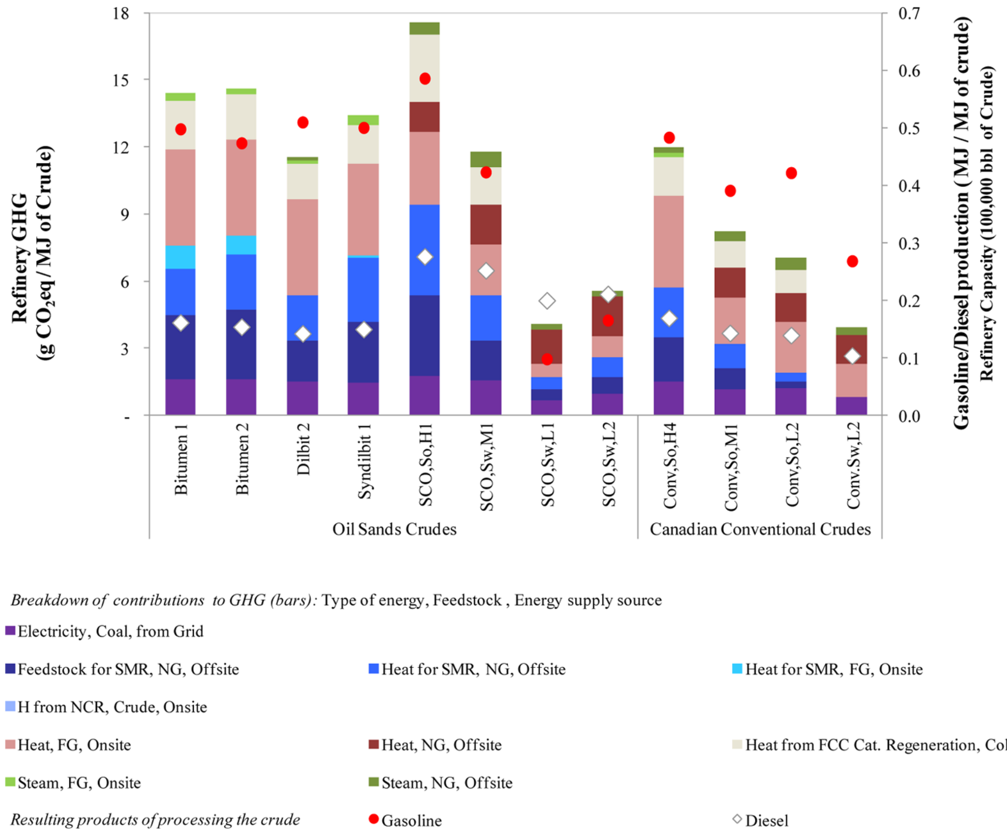


Figure 1. Base case greenhouse gas (GHG) emissions estimates and gasoline and diesel production from refining 100 000 bbl of different crudes. Major assumptions about base case: (1) Refining configuration is based on API and sulfur properties of the whole crude for both crude categories Conventional and OS-derived crudes: API (light API > 32, medium 32 > API > 22, heavy API <22) and sulfur content (S) (sweet S < 0.5 wt %, sour S > 0.5 wt %). Sweet light crudes (Sw, L) are run in a hydroskimming refinery; sour light (So, L), sweet medium (Sw, M), and sour medium (So, M) crudes are run in a medium conversion refinery; and heavy crudes (H: conventional, bitumen, dilbits) are run in a full conversion refinery. (2) Upgrading process units for the medium conversion refinery include a fluid catalytic cracking (FCC) process unit, and upgrading process units for full/deep conversion refinery include FCC and delayed coking process units. (3) A float case is assumed where crude properties and the refinery configuration (i.e., level of refining) determine the amount of gasoline and diesel produced. (4) Energy sources: hydrogen (H) via steam methane reforming (SMR) of natural gas (NG); refinery fuel gas (FG) from the crude and refining process units (RP) offsets NG consumption. FG is allocated through prioritizing the different NG requirements in the refinery (i.e., heat for processing, heat for steam, heat for SMR, and SMR feedstock) based on its heating value until it is exhausted. Heating values: 46.50 MJ/kg RFG low heating value (LHV) on mass basis and 47.14 MJ/kg NG LHV on mass basis.[58] Byproducts such as H via naphtha catalytic reforming (NCR) and coke deposited on FCC catalyst offset energy requirements as well. FCC regeneration must burn off the coke deposited on FCC catalyst to restore catalyst activity, which releases heat that satisfies most of the heat requirements of the FCC. FCC regeneration coke burned to complete combustion (coke yield 5.5 wt % FCC feed[35] and coke carbon content 85 wt %).[59] (5) Combustion GHG emissions factor is assumed the same for NG and FG combustion (56.6 g CO_2eq/MJ). H via NCR does not have any share of emissions due to allocation method employed. Electricity 100% coal-fired power (329 g CO_2 eq/MJ).[58] SI shows GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

other final products is taken into account. In PRELIM, the default refinery configuration is set based on a set of three broad refinery categories: hydroskimming refinery, medium conversion refinery, and deep conversion refinery[46] as suggested by Marano.[47] All 10 refinery configurations in PRELIM fit into one of these three categories. The base case assigns each crude (OS and conventional) to the appropriate default refinery category, using API gravity and sulfur content of the whole crude as the criteria. Default process energy requirements are represented by literature values. A float case is assumed where crude properties and the refinery configuration determine the final product slate. When the alternative functional units are explored, refinery emissions are allocated to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios. The SI details additional assumptions.

Four possible alternative refinery operating scenarios are created from a screening of parameters through sensitivity analysis and a collection of a range of plausible values for each parameter. These scenarios explore the impact of different refinery configurations available in PRELIM (crudes will not always end up in the default refinery configuration); variations in process energy requirements (greater efficiencies are possible than currently represented by the default values used); and, variations in fuel gas production calculations (a parameter that greatly varies throughout the industry).

Results are presented for a total of 12 assays out of the 29 present in PRELIM's assay inventory, selected to represent a range of qualities of crude for each category of crude (Table 1). For example, diluted bitumen is represented by "dilbit 2" and "syndilbit 1". These two assays are selected as they represent the highest and lowest overall refinery GHG emissions estimates respectively from the eight assays of diluted bitumen

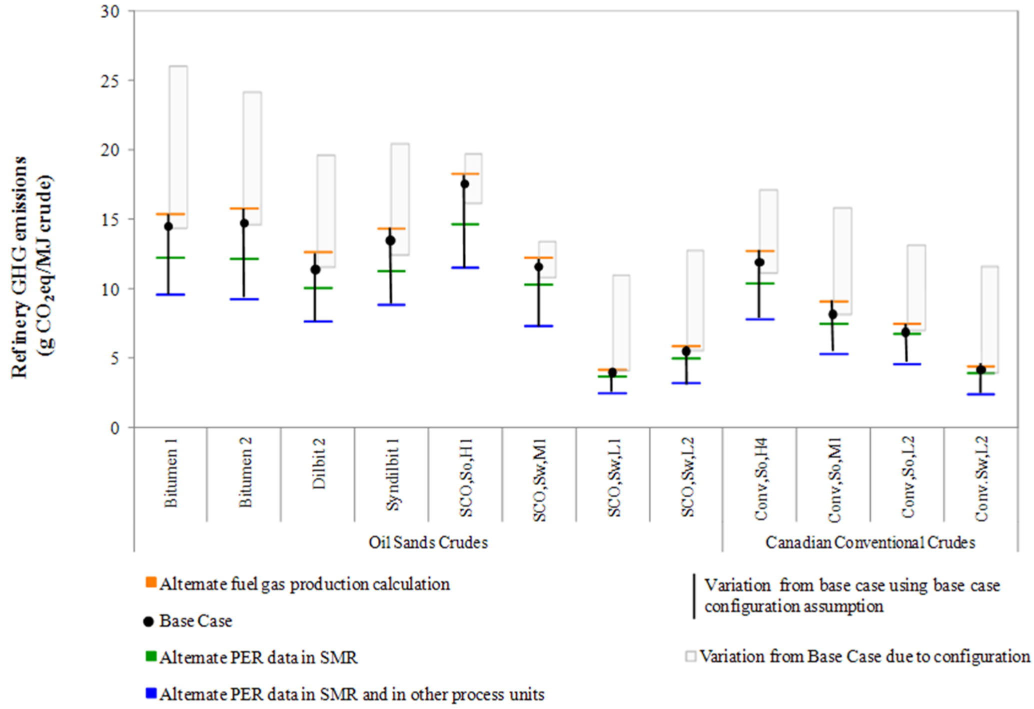


Figure 2. Scenario analysis overall refinery greenhouse gas (GHG) emissions. Scenarios: The base case represents the assumptions presented in Figure 1. Alternate process energy requirements (PER) data in steam methane reforming (SMR) uses a 91% energy efficiency as MJ hydrogen produced/MJ net energy use; energy use accounts for steam production inside SMR that is exported to other process units.[26] Alternate PER in SMR and in other process units simulate additional improvements on energy requirements in other refinery process units based on process energy use confidential data (overall efficiency improvement of approximately 30%). Alternate fuel gas production calculation assesses increasing refinery fuel gas production using an alternative calculation method to determine fuel gas production in hydrotreating process units. PRELIM uses a simple method to determine the amount of refinery fuel gas. The alternative calculation is based on hydrogen requirement specific to each crude while holding other base case assumptions constant that ends in high estimates in the amount of refinery fuel gas (average increase of 2.5% across all process units); variations in emissions are mainly associated with the hydrogen content of the total amount of refinery fuel gas. Variation from Base Case due to configuration defines range of GHG estimates associated with use of different refinery configurations while holding other base case assumptions constant. The SI shows scenario analysis estimates of GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

in the assay inventory. Publicly available assay data are used for all OS assays with the exception of raw bitumen which is currently not processed directly in a refinery so data are not publicly available. The publicly available assays are streams or blends of crudes of different qualities flowing through pipelines in Canada. These streams were used to represent specific crude categories (e.g., diluted bitumen, SCO) through consultation with industry and academic experts to ensure that they represent an accurate range of characteristics for each category of OS-derived crudes. Conventional crudes are presented for the purposes of comparison. Table 1 provides a summary of all 12 assays, current production volumes of each crude category, source of data, and properties of the whole crude.

■ RESULTS

Base Case Results. Under the base case assumptions, total refinery energy use ranges from 0.06 to 0.24 MJ/MJ of crude (340−1400 MJ/bbl of crude). A detailed discussion of energy use is presented in SI. As expected, energy use has a positive linear relationship with the GHG emissions. The resulting GHG emissions of processing crudes of different qualities can vary widely, mainly due to differences in hydrogen requirements. Total refinery GHG emissions range from 4 to 18 g CO_2eq/MJ of crude being processed (23−110 kg CO_2eq/bbl of crude). For the 12 crudes considered in the base case, the supply of hydrogen contributes from 0 to 44% of refinery emissions, process heating contributes 26−71%, FCC catalyst regeneration contributes 0−17%, steam contributes 2−7%, and electricity contributes 10−21%. Up to 48% of the emissions associated with hydrogen requirements result from the chemical transformation of natural gas into hydrogen in the SMR process unit. Zero emissions from hydrogen supply are possible where hydrogen requirements are low enough to be met by coproduction of hydrogen via naphtha catalytic reforming. This form of hydrogen is considered to be a byproduct and therefore a CO_2eq emissions-free stream as the base case assumes that emissions are allocated only to final refinery products. Generally, the GHG emissions estimates from each energy type are proportional to their contribution to overall energy use with the exception of electricity, for which emissions are determined by the emissions intensity of electricity production (further discussion in SI).

Figure 1 shows that the amount of gasoline and diesel produced from the same amount of input (i.e., 100 000 barrels of crude) also varies with crude quality, but to different extents (further details in SI).

Alternative Scenario Results. Figure 2 presents the base case GHG emissions (also presented in Figure 1) for each crude as well as variation from the base case due to changes in assumptions regarding refinery configuration, process energy requirements, energy use for production of hydrogen via SMR, and refinery fuel gas production.

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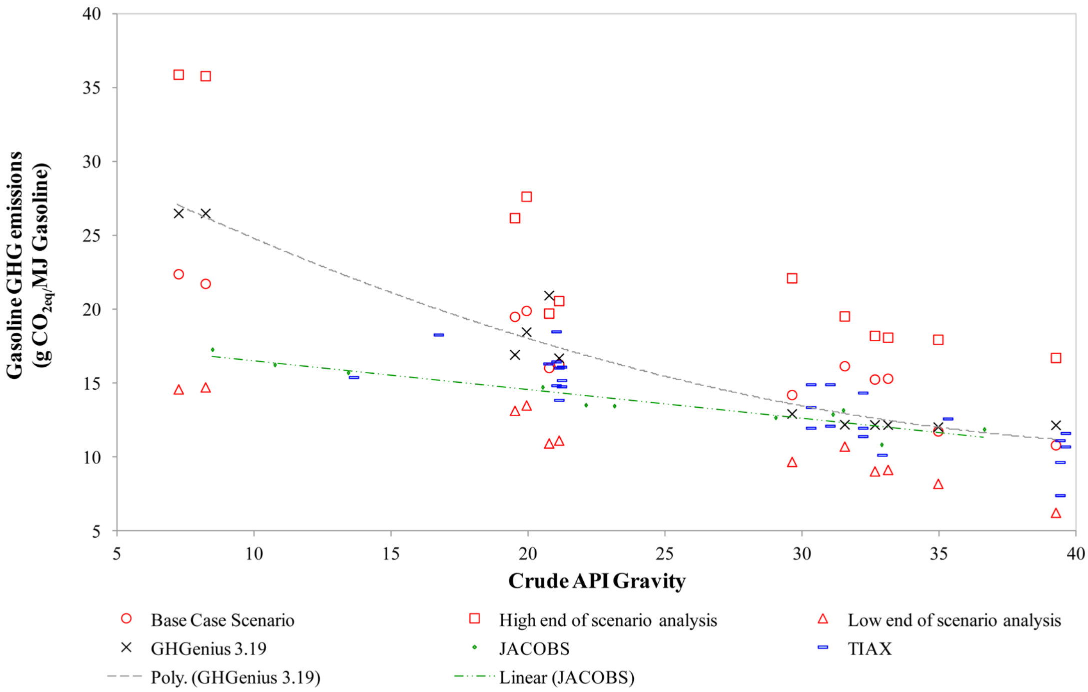

Figure 3. Comparison of GHGenius, JACOBS, TIAX, and PRELIM gasoline greenhouse gas (GHG) estimates. Base case estimates and variation from the scenario analysis presented in Figure 1. Variation from base case can be compared with variation in TIAX estimates;[17] TIAX study accounted for alternative configurations and/or energy efficiencies (i.e., different U.S. production regions). If PRELIM uses the same configuration as JACOBS[22] while holding other assumptions to base case constants, PRELIM replicates similar linear regression as JACOBS results suggest. GHGenius[60] estimates are from default GHGenius v.3.19 assumptions while varying API gravity and sulfur of crude using PRELIM assay inventory (polynomial regression built in GHGenius from crude slates of API > 25.4 and using Canadian industry forecast data). The GREET model emissions estimates are not included in the figure as there is no variation presented due to crude quality (the default gasoline carbon intensity is estimated at 10.5 g CO2eq/MJ of gasoline). Gerdes model estimates[25] and recent GHGenius estimates[61] using a linear relationship approach (which are not included in the figure) are also in the range of gasoline GHG emissions estimates resulting from the low end of the scenario analysis and TIAX as illustrated by Brandt.[49] These estimates are not included in the figure as they are either duplications of the same data or present very similar trends and ranges.

The magnitude of the impact on results from varying the refinery configuration is crude-specific but in general this factor has a greater impact than any other individual factor considered. When the full range of refinery configurations are run for each crude, the emissions can change as much as 12 g CO_2eq/MJ of crude (71 kg/bbl of Bitumen1) or up to 190% (Conv,Sw,L2: conventional sweet light crude 2 as indicated in Figure 2). Lighter and sweeter (lower in sulfur) crudes have increased GHG emissions above the base case since the base case assumes a simple hydroskimming configuration, and for heavier crudes (OS and conventional) there are deep conversion configurations in which the GHG emissions are higher or lower than those estimated in the base case. Therefore, the method used in the base case for assigning crudes to a default or "ideal" level of conversion is incomplete if the goal is to predict the full range of potential GHG emissions associated with refining a particular crude (as a crude could be processed in a variety of refineries with different configurations). Therefore, the specific refinery configuration and the associated process units play an important role.

Process unit energy requirements, as well as refinery fuel gas production, can vary significantly and collectively; this variation can result in a wide range of emissions estimates, implying that attention has to be placed on these assumptions and their implications for policy. Improving energy use in hydrotreating, FCC, naphtha catalytic reforming, delayed coking, and SMR process units (represented by real refinery operating data with higher levels of efficiency than the literature data used in the base case—overall efficiency improvement of approximately 30%) decrease GHG emissions by 34% (5 g CO_2eq/MJ of Bitumen1) to 43% (2 g CO_2eq/MJ of SCO,Sw,L2). Increasing the estimated production of refinery fuel gas (average increase of 2.5% across all process units) can increase GHG emissions by as little as 1% (0.02 g CO_2eq/MJ of SCO,Sw,L1) or as much as 10% (0.8 g CO_2eq/MJ of Conv,So,M1; up to 1 g CO_2eq/MJ of Bitumen 1). The SI details results of other scenarios.

As a whole, Figure 2 illustrates that a wider range of GHG emissions estimates is seen for OS products (2.5−26 g CO_2eq/MJ of crude) compared to conventional crudes (2.4−17 kg CO_2eq/MJ of crude). Generally, the highest estimates are for bitumen (9.3−26 kg CO_2eq/MJ of crude). This represents potential cases such as dilbit being sent to a refinery and the diluent being separated and returned to the OS operation. GHG emissions from refining diluted bitumen range between 7.6 and 20 g CO_2eq/MJ of crude. The SCOs represent one of the highest and the lowest GHG emissions of all crudes considered. The heavy SCO crude category can have GHG emissions as high as 20 g CO_2eq/MJ of crude. Light sweet SCO can have GHG emissions as low as 2.5 g CO_2eq/MJ of crude. Light/heavy crude differentials may provide an incentive for the production of light SCO; however, this differential can decrease in a market with increasing supply of heavy oil and refineries increasing their capabilities to manage that feedstock. The SI discusses PRELIM's SCO refinery GHG emissions estimates in detail. It is important to note that the high and low ends of the GHG emissions for OS crudes represent the cases of recycling of diluent (bitumen as a feedstock) and upgrading the bitumen prior to entering the refinery (high quality SCO) which have upstream processing requirements quite different from conventional crudes and will have different implications on a full LC basis.[48]

Alternative Functional Units. Given recent regulations such as the CA-LCFS, there has been increased interest in representing LC emissions on a per product basis. This requires allocation of total refinery emissions to each product. Assuming GHG emissions are allocated only to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios, conventional crudes' gasoline GHG emissions estimates range from 6.2 to 22 g CO_2eq/MJ of gasoline, and OS products' GHG emissions estimates range from 9.0 to 36 g CO_2eq/MJ of gasoline. Diesel GHG emissions estimates for conventional crudes and OS products range from 2.3 to 26 g CO_2eq/of MJ of diesel and 3.3 to 36 g CO_2eq/MJ of diesel, respectively. Figure S5 illustrates gasoline and diesel GHG emissions estimates for the scenario analysis. The implications of different allocation methods are explored in the SI.

Overall refinery GHG emissions (i.e., per bbl or MJ of crude) will be greatly influenced by the refinery configuration employed. However, for some crudes, when the emissions are calculated on a per product basis (e.g., per MJ gasoline) the impact of the configuration can play a lesser role as the significant differences in emissions between configurations are tempered by the differences in the amount of product produced (Figure S5). For example, if light sweet SCO is processed in a deep conversion refinery instead of a hydroskimming refinery, it will undergo more intense processing and therefore result in both higher overall emissions as well as a higher volume of gasoline produced. This difference has implications in terms of potentially providing an incentive for one action (e.g., sell SCO to hydroskimming refinery) if the crude is being evaluated on an overall crude basis (i.e., all products) and a second action if it is evaluated on an individual product basis (e.g., sell SCO to deep conversion refinery).

Comparison with Other Studies. In the absence of a public-domain refinery modeling tool, the use of regression models based on sulfur content and API gravity of the whole crude is being generalized for the purposes of modeling crude quality effects on refinery GHG emissions.[49] Some studies assume a linear relationship[18,22,25] while others assume a quadratic relationship[15] for the regression model, and consensus has not yet been reached. The results reported by previous refinery models/studies are within the ranges calculated by the PRELIM model (Figures S6–S7). Figure 3 demonstrates that the degree of correlation between the gasoline GHG emissions estimates from refining and the whole crude API gravity is affected by assumptions about configuration and process energy requirements. This is also true for diesel (Figure S8). In addition, sulfur does not make a large contribution to predicting GHG emissions. PRELIM can replicate the results of previous studies when similar assumptions are made. However, the figure shows that previous studies do not provide the full range of emissions possible.

■ DISCUSSION

PRELIM goes beyond public LC-based modeling approaches by adding the detail required to evaluate the impact of crude quality and refinery configuration on energy use and GHG emissions of refining while remaining a transparent spreadsheet-based tool. The model is based on public data but is validated by confidential operating data and expert review. This approach allows for improved confidence in the model results while providing the detail required for users to replicate the results and make use of the framework. It provides more detailed calculations (e.g., includes a hydrogen balance at a process unit level) than current LC models but with less detail (thereby increasing manageability/transparency) than proprietary refinery energy optimization models. PRELIM is capable of replicating the findings from more complex models with an overall margin deviation below 10% in almost all cases, which is within the bounds of typical LC inventories.[41−43] PRELIM provides a data framework that can be integrated as a module in Well-To-Wheel models and used by academia, industry, and government to develop a consistent reporting structure for data in support of GHG emissions modeling for policy purposes.

Further model development should include the establishment of a statistical relationship between hydrogen content, aromatic hydrocarbon content, and the emissions intensity of processing a specific crude. The current assumption of processing all crudes to the same intermediate product specification may overestimate energy requirements for high quality crudes in medium and deep conversion refineries. Also, it is recommended that opportunities to improve the accuracy of hydrogen requirement estimates be explored. The inclusion of modeling crude input slates instead of individual crudes, economic data, and other environmental impacts, as well as tools for decision-making analysis such as Monte Carlo simulation, will enhance model capabilities.

The PRELIM application presented in this paper demonstrates that crude quality and the selected process units employed (i.e., the refinery configuration), as well as the energy efficiency of the process units, all play important roles in determining the energy requirements and emissions of processing a crude. The unique amount of hydrogen required to process each crude is dictated by the quality of the crude entering the refinery. It can be the major contributor to refinery energy use and GHG emissions for every crude. Therefore, this should be a key parameter used in estimating emissions. Emissions associated with providing the hydrogen required should also be the focus of emissions reductions at refineries.

This analysis provides insights that can help to inform emissions reductions decisions at refineries. Based on this analysis, the top three ways to reduce GHG emissions at refineries processing heavier crude will be to (1) reduce the amount of hydrogen consumed, (2) increase hydrogen production efficiency (and/or lower GHG emissions intensity of hydrogen production), and (3) capture CO_2 from the most concentrated, highest volume sources (i.e., FCC and SMR). All of these alternatives involve several technologies that require further study and can be included as new modules in future versions of PRELIM. Moreover, the results suggest that there may be a "preferred" configuration to process a specific crude. Opportunities for reductions in GHG emissions such as processing high quality crudes in low complexity refineries (hydroskimming and medium conversion) instead of deep conversion refineries could be investigated. However, these opportunities will be limited by the decreasing number of low complexity refineries in North America available to process these types of crude feedstocks. This serves as a reminder that the range of refinery emissions for OS products, as for other crudes, is linked to refining industry investments made over the next decade.

This analysis substantiates the claim that more accurate assessments of refinery emissions are required to better inform LC-based policies and avoid potential unintended consequences. Putting the refinery emissions variations into context, the variability in GHG emissions in the refining stage that results from processing crudes of different qualities is as significant as the magnitude expected in upstream operations (e.g., in this paper, the variability is up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 CO_2eq/MJ of diesel—based on the full range of base case crudes). If crudes are run through the same configuration, refinery performance (defined by efficiency of energy use) introduces important variation. The PRELIM application demonstrated up to 43% deviation in the GHG emissions burden attributed to a crude solely by varying the efficiency of the process units in one configuration. This implies that impacts of crude quality and refinery configuration should be modeled in the refining stage of LC analyses of petroleum-based fuels. Also, climate policies based on LCA should equally engage both parts of the supply chain (i.e., crude production/processing/transport and refining stages) to encourage the most cost-effective GHG emissions mitigation pathways. Directives such as the current High Carbon Intensity Crude Oil (HCICO) provision in the CA-LCFS that do not explicitly include these differences in the definition and principles/goals could lead to unintended consequences.[50,51]

The results also show that API gravity and sulfur content of the whole crude are not sufficient to characterize the refinery energy use and GHG emissions specific to a crude. The use of these simple metrics within policies that are intended to differentiate the LC emissions of different crudes can also lead to unintended consequences. Energy efficiency of the process units and refinery configuration play a large role in explaining the variation in possible estimates. Ideally, the assay data like those presented in PRELIM should be collected and used as it improves accuracy beyond whole crude properties. However, since these data tend to be highly proprietary, we recommend that at minimum the crude distillation curve and the hydrogen content of the crude fractions be accounted for. Future efforts should focus on striking the balance between reporting the best data in a transparent way and protecting sensitive information. A starting point could be exploring the use of refining industry data and methods such as the Nelson index and/or Solomon energy efficiency index to simplify the characterization of refinery configurations;[52−55] however, an innovative approach will also be needed to represent crude quality parameters.

The PRELIM application shown in this paper demonstrates the strengths of detailed process modeling for understanding and assessing petroleum refinery GHG emissions sources with the ultimate goal of more informed decisions regarding the increased use of heavy oil in North America.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Details on literature review, methods, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

■ ACKNOWLEDGMENTS

We thank Natural Resources Canada, Alberta Innovates-Energy and Environment Solutions, and Oil Sands Industry Consortium for financial support and insights helpful to the research. We also thank Damien Hocking (MEG Energy), Nicolas Choquette-Levy (University of Calgary), and Prof. Heather MacLean, Jennifer McKellar, and Diana Pacheco (University of Toronto) for helpful feedback on the research. Any opinions, findings, and recommendations expressed in this material are those of the authors.

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Attachment 18

Toxic and fine particulate emissions from U.S. refinery coking and cracking of 'tar sands' oils

Greg Karras (2015).*

Emissions of toxic and criteria air pollutants from delayed coking units (DCUs) and catalytic cracking units (CCUs) were assessed for scenarios in which 20–50% of current US refinery crude oil feed might be replaced by diluted bitumen (dilbit) oils. Refinery- and process-level data for feedstock properties, process capabilities, and emissions were compared across the US industry to estimate changes in processing needed to maintain transport fuels production from the changing feedstock, and in resultant emissions. The shift from mid-barrel to denser and more contaminated oils from crude distillation of dilbits could swing hydrocracking to diesel and jet fuel and would increase DCU and CCU feed rates and coke yields. Volatile emissions from DCUs could increase by 14–47% and coke combustion emissions from CCUs could increase by 14–25% in +20–50% dilbit scenarios. Condensable particulate matter emissions from CCUs could increase by 500–1,300 metric tons per year (t/y) in the +20% dilbit scenario and 900–2,400 t/y in the +50% dilbit scenario. Benzene emissions from DCUs, though poorly measured, might increase by 46–95 t/y, and 150–320 t/y, in the respective scenarios. These industry-wide estimates for US DCUs and CCUs assume a plausible but elective crude oil switch without mitigation, and are limited by a paucity of measurements for most of the >100 toxic chemicals found in emissions from these units. Future work might focus on feedstock-driven changes in storage tank, hydroprocessing, and coker byproduct emissions.

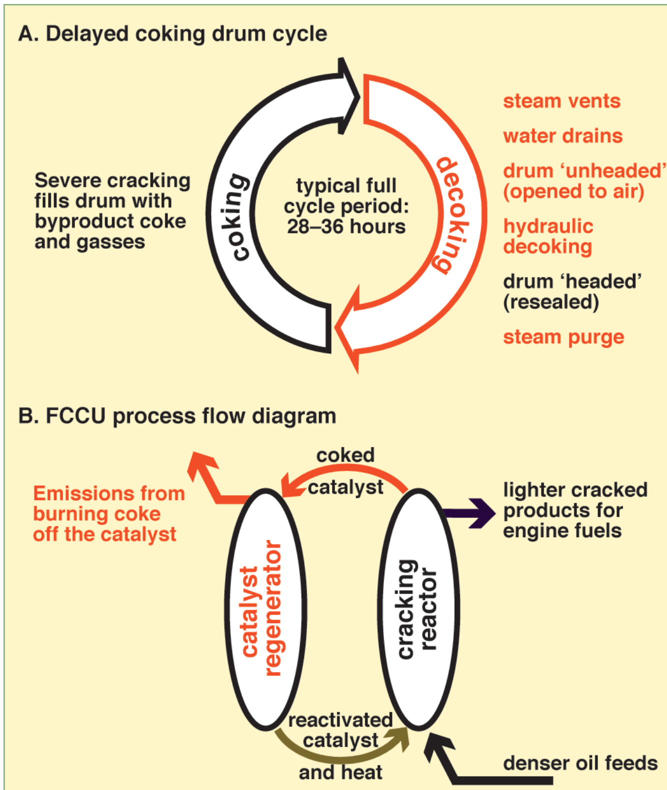

Figure 1. Delayed coking coke drum cycle (A); and fluid catalytic cracking process flow diagram (B). Primary direct emission sources are shown in red.

Introduction

US refineries have gradually shifted to denser, more contaminated, lower quality crude feeds over three decades[1] and have begun to exploit vast potential supplies of still denser and more contaminated heavy oil and bitumen.[2, 3] Bitumen—'tar sands' oil—is fundamentally different from conventional crude.[3] Processing lower quality oil is known to increase oil refining pollution intensity by increasing the pass-through of toxic elements in the oils,[4] the fuel combustion for energy needed to refine them[5–10] and the frequency and magnitude of plant upsets, spills, fires and flaring.[11–13] However, relatively little has been done to characterize feedstock-driven emissions from some high-emitting refinery processes—including the delayed coking and catalytic cracking processes.

Delayed coking units (DCUs) account for ≈95% of U.S. refining capacity to thermally crack residuum (resid),[14] the densest and most contaminated fraction (cut) of crude from atmospheric or vacuum distillation. DCUs perform severe thermal cracking at ≈415–515 ºC and ≈15–90 psi for hours to yield liquid oils and contaminated byproducts that are typically burned as fuels, including hydrocarbon gasses, and petroleum coke that can be 9–12% volatile chemicals.[15–18] This is a batch process that must interrupt feed to each reactor vessel (drum) to remove the coke, so DCUs typically have 2–8 drums in order to process resid semicontinuously. Decoking involves venting the drum, draining quench water from it, opening it to drill out the coke, and purging the drum after it is resealed—and all of that can introduce volatile chemicals to the atmosphere. *See* Figure 1. Direct measurements suggest that this inherently polluting design may place DCUs among the largest sources of volatile organic compounds such as benzene in refineries.[19]

Catalytic cracking units (CCUs) account for ≈83% of US refinery capacity to crack heavy gas oil (HGO).[14] HGO distills at ≈343–566 ºC and is the second densest, second most contaminated cut of whole crude after resid.

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Famously developed and deployed to convert HGO into high-octane gasoline, the process also can run resid,[15–17] cycling the resid back into the reactor along with fresh feed, and many CCUs use this 'recycle' capacity.[14, 20] Cracking occurs at ≈480–540 ºC and ≈10–20 psi in the presence of a catalyst to yield naphtha (gasoline feedstock), distillates (diesel and jet fuel feedstock), and byproduct gasses and coke.[15–17, 21] The process is continuous. High-boiling hydrocarbons condense to deposit coke on the catalyst continuously, the catalyst cycles between the reactor and a 'regenerator' that reactivates the catalyst by burning the coke off of it continuously, and coke burn-off also heats the process. *See* Figure 1. Coke is high-emitting fuel. CCU 'catalyst' coke accounts for ≈99% of coke burned in US refineries.[22] CCUs are among the highest emitting refinery sources of combustion products such as condensable particulate matter (cPM).[23, 24]

Bitumen is tar like or semi-solid petroleum that requires ≈2–3 times more energy to extract, and to refine for engine fuels, than conventional crude, making it inherently high-emitting oil.[5–10] Too viscous to transport by itself, bitumen is mixed with diluent oils such as naphtha in commercially exploited crude streams, and these diluent/bitumen blends are called dilbits. Distillation properties of dilbits differ markedly from those of the crude slate most US refineries were designed to process efficiently or process now. Figure 2 illustrates these differences. Dilbit distillation yield is low for HGO, especially low for mid-barrel distillates, and especially high for resid compared with the current average US crude slate and the Strategic Petroleum Reserve (SPR). Dilbit HGO and resid cuts also are very dense (low API) and high in sulfur. Distillates are diesel and jet fuel feedstocks, while resid is fed to DCUs and CCUs to produce additional HGO that is added to CCU and hydrocracker feeds to produce distillate as well as naphtha. In other words, refining these high-resid, low-distillate oils means more DCU and CCU feedstock and more need for DCU and CCU products.

Process controls that are added onto the basic process design can capture or avoid a substantial part of process emissions, but technically feasible controls might not be deployed comprehensively, effectively, or at all, and in any case can control only a percentage of emissions generated by an inherently polluting design.[18–20, 24–26] At any given level of such add-on controls, emissions are ultimately a function of process air pollutant generation. An example is increasing coke burn rate with increasing CCU feed rate, illustrated by data from a California plant in Figure 3: federal limits on PM emitted *per ton* coke burned in this CCU would not address its emissions from burning tons *per day* more coke. By increasing total DCU decoking cycle throughput, increasing CCU coke generation and burn-off, or both, changes in process feedstock associated with refining more dilbit would have the potential to increase emissions.

The work reported here compares publicly reported oil quality, processing, and emissions data to estimate refining sector-level changes in DCU and CCU processing, and emissions of toxic air pollutants and cPM, that could result from adding more dilbit oils to the US crude slate.

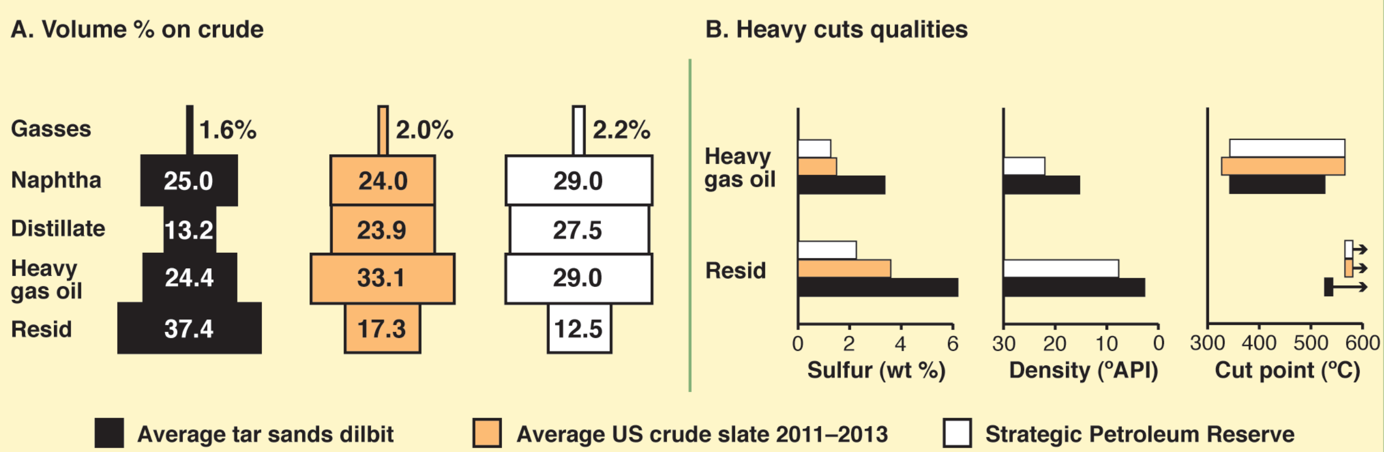

Figure 2. Distillation properties of dilbit, the current US refinery crude slate, and the US Strategic Petroleum Reserve. Data from Crudemonitor (2014); The ICCT (2013); and DOE (2002). *See* Supplemental Information, tables S1 and S2 for details. Heavy cut densities were not reported by The ICCT (2013) and were not available for the US Crude slate.

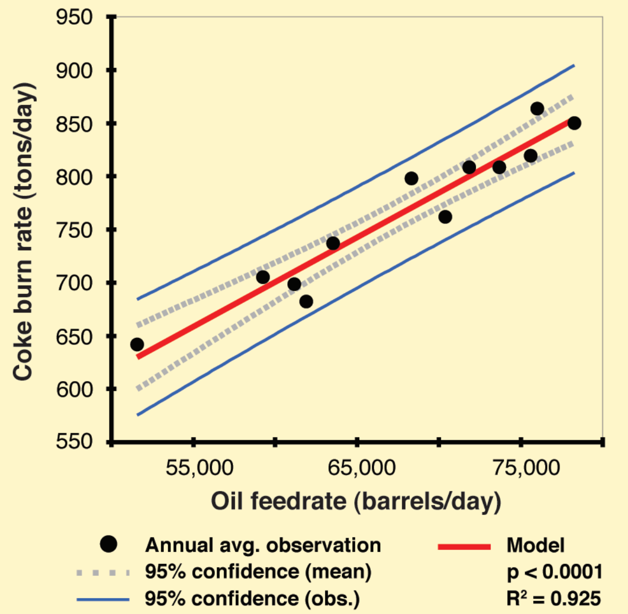

Figure 3. CCU coke burn *v.* feedrate, Chevron Richmond refinery. Coke burn increases in proportion to feed, consistent with the lack of change to feed quality reported during the period shown. Data from BAAQMD. See Reference 24.

Data and methods

Feedstock data for diluted bitumen (dilbit) oils and for the current average US refinery crude blend (slate) during 2011–2013 were reported by the oil industry, the International Council on Clean Transportation (ICCT), and the US Geological Survey, Department of Energy, and Energy Information Administration (EIA).[1, 3, 27–33] *(Data summarized here are provided, along with methods details, in the Supplemental Information (SI).)*

Crude density, sulfur content, and distillation properties varied little among dilbits,[27] reflecting the intentional blending of these oils, and supporting the calculation of the 'average' dilbit shown in Figure 2. Properties of the current average US refinery crude slate were based on whole crude volume, density and sulfur content in 2013 reported by the EIA[1, 30] and distillation yields estimated for 2011 by The ICCT.[28] EIA did not report distillation yield for the US crude slate, but did report US refinery operating data that supported the ICCT estimate. These values for 2013 reported by EIA were within 0.2%, 2.2%, 0.0%, and 1.2% of the ICCT estimate for whole crude density, whole crude sulfur content, HGO distillation yield processed in downstream units, and resid yield processed downstream, respectively. *(SI Table S2.)*

Potential changes in distillation yields were calculated as weighted averages for barrel-for-barrel replacement of the current average US crude slate with 20%, and 50%, more of the average dilbit. Results confirmed the potential for changes in the volume, density, and sulfur content of distillate, HGO, and resid yields from crude distillation that are suggested in Figure 2. See Table 1.

Processing data for the conversion of resid and HGO into feedstocks for gasoline, diesel and jet fuel finishing (naphtha and distillate) were reported by the EIA and the petroleum engineering literature.[15–17, 21, 31–34] Observed process capacities and oil feed rates confirmed the dominance of DCUs and CCUs among US refinery conversion (cracking) processes, and also the significant role played by hydrocracking units (HCUs).[31, 33, 34] HCU capacity to crack gas oil was 1.297 million barrels/day (MMb/d), or 64% of total US HCU capacity, in 2014. *(SI Table S4.)* The HCU process differs from those of DCUs and CCUs in its use of hydrogen addition rather than carbon subtraction chemistry to accomplish cracking,[15–17] and in its ability to 'swing' between naphtha (gasoline) and distillate (diesel and jet fuel) production targets.[21] That ability would be important in addressing the loss of distillate from crude distillation of dilbits revealed in Table 1. For these reasons, gas oil HCUs were included in the analysis of conversion process changes that could result from adding more dilbit to the US crude slate.

Comparisons of +20–50% dilbit scenario distillation yields with current process capacities and rates revealed limited capacity to convert the additional resid into lighter feedstocks unless CCUs processed some of this resid or new coking capacity was built. *(SI tables S3–S7.)* While both solutions are technically feasible and each likely would be used in some cases, it was judged more likely overall that existing capacity would generally be used first before adding new capacity. Thus processing of resid in both DCUs and CCUs, with feed recycling to improve conversion in CCUs, was analyzed for these scenarios. Greater densities and sulfur contents of unit feeds containing more dilbit-derived resid is one important implication for processing in these scenarios.

Process design and operating data showed that, while product yields vary with unit design and operating details, when other factors were optimized, denser and higher sulfur feeds reduce liquid yields and increase coke yields from DCUs and CCUs. *(SI Table S5.)* Conversion process yield data that were found to best represent current and +20–50% dilbit scenario average process capacities and feeds are summarized in Table 2.

The DCU yields shown in Table 2 for 8.2 °API, 3.4% sulfur feed were applied to both the current slate and the +20–50% dilbit slates. However, dilbit-derived resid (Figure 2) is denser than 8.2 °API and exceeds 3.4% sul-

Table 1. Potential changes in distillation yields from 20–50% more dilbit in the US crude slate.

		Current (2011-13)	20/80 dilbit/current scenario		50/50 dilbit/current scenario	
		Crude slate	Crude slate	Change (Δ)	Crude slate	Change (Δ)
Crude						
Volume	(MMb/d)	15.312	15.312	None	15.312	None
Density	(kg/m^3)	872	883	Denser	899	Denser
Sulfur	(wt. %)	1.4%	1.9%	More sulfur	2.6%	More sulfur
Yield volumes						
Gasses	(MMb/d)	0.306	0.295	–0.011	0.279	–0.027
Naphtha	(MMb/d)	3.675	3.707	0.032	3.754	0.079
Distillate	(MMb/d)	3.660	3.332	–0.328	2.840	–0.820
HGO	(MMb/d)	5.068	4.801	–0.267	4.399	–0.669
Resid	(MMb/d)	2.649	3.264	0.615	4.188	1.539

Data from references 1 and 27–33. *See* SI Table S3 for details.

fur. If actual DCU yield in the dilbit scenarios is closer to that shown in Table 2 for the 4°API, 5.3% sulfur feed, this analysis might underestimate DCU and CCU feed rate increments in those scenarios. Similarly, although CCU yield data for the lighter feed shown in Table 2 was applied in the current baseline while that for the denser, 15.1 °API (3.3 % sulfur) feed was applied in the dilbit scenarios, CCUs would feed denser, higher sulfur resid derived from dilbit in those scenarios. If actual yields in the dilbit scenarios are lower than this 15.1 °API, 3.3% sulfur feed data estimate for light liquids, or if they are higher for coke, or both, this might underestimate CCU feed rate increments and coke-burn emissions in those scenarios. The use of these process yields for dilbits thus represents a conservative assumption.

These process yield data were applied to the crude distillation volume changes shown in Table 1 to estimate the changes in DCU, CCU, and gas oil HCU process feeds and rates that would be needed to maintain naphtha and distillate production in the +20–50% dilbit scenarios. The estimates were further constrained by an additional objective to use existing DCU and CCU capacity before adding conversion capacity. As stated, this approach used existing CCU capacity for resid as well as HGO feed. Gas oil HCU 'swing' capacity was used to balance naphtha and distillate production so that both fuel feedstocks were maintained at current production volume. Other approaches are feasible but the cost of new capacity and value of motor fuel products was judged to support this approach. A check on this approach showed that, without changing CCU feeds, substantially more coking capacity was needed to approach current product yields even in the +20% dilbit scenario *(SI Table S7),* and growing or stable US refinery production rates with growing exports of these key products *(SI Table S8)* also supported this approach. Various changes in equipment (e.g., pumps, distillation internals) and product shifts among plants would be needed in any case.

Emissions were estimated relative to current conditions in percent, and as mass-rates for selected pollutants. The incremental emissions from DCUs were based on the volume of volatile material processed in the coke drums

Table 2. Representative conversion process yields by unit feed quality or product target.

		Delayed coking[a]		Catalytic cracking[b]		Gas oil hydrocracking[c]	
Product target		——	——	——	——	naphtha	distillate
Feed quality							
density	(°API)	8.2	4.0	20.1	15.1	22	22
sulfur	(wt. %)	3.4	5.3	0.5	3.3	2.5	2.5
Process yields							
naphtha	(vol. %)	19	24	58	51	90	29
distillate	(vol. %)	——	——	18	21	——	69
HGO	(vol. %)	45	30	——	——	——	——
coke	(wt. %)	25	35	7.0	10.3	——	——

(a) Data from reference 15. (b) Data from reference 17. (c) Data from reference 21. *See* SI Table S5 for details.

and thus exposed to the atmosphere during decoking. This was estimated as the increase in DCU feed volume rate for each dilbit scenario by the analysis of process changes described above. Incremental emissions from CCUs were based on the mass of coke burned in CCUs. This was estimated from the increments for CCU coke yield (wt. %), feed vol./day, and feed density (current HGO ≈ 922 kg/m^3; dilbit resid ≈ 1,055 kg/m^3) found by the analysis of process changes. *(SI Table S6.)*

Mass emission rates were estimated by applying these relative increments to available measurements of specific pollutants in current 'baseline' DCU and CCU emissions.

Direct measurements of emissions were reported by Chambers et al.,[19] US EPA,[20] the Bay Area Air Quality Management District,[35, 36] and Sánchez de la Campa et al.[37] Some 114 toxic chemicals were found in emissions from DCUs, CCUs, or both.[20] *(SI Table S9.)* But only a handful of these pollutants were measured above method detection levels (MDLs) consistently at multiple plants.[20]

DCU source tests for a 2011 Information Collection Request (ICR) used sampling methods for other sources that often collected too little sample for analysis.[20] Source tests were reported for 5 DCUs. Multiple tests were below MDLs in all runs for nearly every analyte except VOC, methane, and benzene (measured in 5, 5, and 4 of the tests, respectively). Emissions/barrel DCU feed reported for VOC, methane and benzene ranged by more than two orders of magnitude, but only DCU vents—not coke drilling or other decoking steps—were measured.[20]

Direct measurements of DCU decoking emissions by differential absorption light detection and ranging (DIAL)[19] found VOC and benzene emissions that exceeded the ICR vent emissions maxima by 1–2 orders of magnitude. *(SI Table S12.)* These DIAL measurements were validated and close to the median results from 16 other refineries.[19] Based on these data, vent tests alone may understate DCU emissions substantially. The DIAL data were judged more representative of DCU emissions, but only one unit was measured and ≈ half of its emissions were from coke water handling. DIAL data were scaled to the minimum decoking frequency for DCUs and minimum decoking emission period measured, and coke water emissions were removed from the lower bound values, in the estimate derived from these data. *(SI tables S11, S12.)* This estimate, shown in Table 3, was judged to be the most conservative available based on the limited data from direct measurements of total decoking emissions. A check against benzene emissions in the Toxic Chemical Release Inventory (TRI) that were self-reported by refiners *(SI Table S15)* found that this estimate accounted for 60% of total TRI benzene emissions from US refineries at the lower bound and 125% of them at the upper bound, suggesting DCUs are a strong source, and that either TRI emissions are underestimated, or that US refiners handle coke water differently from the refinery tested by DIAL.

Table 3. Delayed coker emission rates estimate.

Emissions per barrel (b) of coker feed

	Lower bound	Upper bound
Benzene (mg/b)	390	810
Methane (grams/b)	38	78
C_{2+} VOC (grams/b)	63	130

Upper bound estimates include emissions from coke water handling. Data from reference 19 and SI tables S11, S12.

Source tests of 11 refiners' CCUs were reported.[20, 35, 36] Emissions were measured above MDLs in one or more test runs at 10 of these CCUs for cPM, 6–8 CCUs for various metals, and 8 CCUs for hydrogen cyanide (HCN). *(SI Table S14.)* Data distributions suggested that median values may better represent the central tendency of the emissions data than arithmetic averages. *(Id.)* However, correlationships among pollutants and operating parameters that were consistent with cPM-boosting effects of ammonia injection, together with the potential that the small data set may under-represent high emitting units, supported 90th Percentile values as an upper bound on emissions estimated from these data. *(Id.)* A check against self-reported TRI emissions *(SI Table S15)* supported this estimate for metals but suggested the possibility that the source tests might not accurately represent average CCU emissions of HCN. Other data show that CCUs are strong emission sources of various pollutants including cPM and metals.[23, 37] Table 4 shows the CCU 'baseline' emission rates estimate for cPM and metals.

Table 4. Catalytic cracking unit (CCU) current 'baseline' emission rates estimate.

Emissions per barrel (b) of CCU feed

		Lower bound	Upper bound
Fine particulate	(g/b)	2.04	5.28
Chromium	(µg/b)	158	243
Lead	(µg/b)	130	284
Manganese	(µg/b)	275	580
Nickel	(µg/b)	481	3,630
Mercury	(µg/b)	22.8	66.1

Lower bound: median value; upper bound: 90th Percentile. Data from references 20, 35, 36 and SI Table S14.

Results

US refining sector-level conversion processing changes needed to maintain naphtha and distillate production in the +20–50% dilbit scenarios are shown in Table 5.

Generally, Table 5 shows changes in oil feed flows and process rates for conversion of the additional resid from distillation of the crude slates containing more dilbit into enough gas oil and distillate to maintain gasoline, diesel, and jet fuel production despite the shortfalls in GO and distillate from crude distillation of the dilbit. Incremental changes from current ‘baseline’ are shown.

In the +20% dilbit (20/80 dilbit/current slate) scenario, coking rate increases to 98% of capacity, producing 0.065 million barrels/d (MMb/d) of additional naphtha and 0.153 MMb/d of gas oil—not enough GO to erase the deficit from crude distillation, but resid feed to CCUs increases more than GO feed drops. Recycling this new resid feed the equivalent of 0.86 times boosts the CCU recycle rate by 0.235 MMb/d, or 5.5 vol. % of total CCU fresh feed. Together with the overall increase in fresh feed (0.161 MMb/d), the net CCU feed rate increment is 0.396 MMb/d. Assuming the CCU yield on this increment for 15.1 ºAPI, 3.3 % sulfur feed in Table 2, these coking and CCU changes boost naphtha to 0.299 MMb/d above baseline while distillate remains 0.245 MMb/d below baseline, allowing HCUs to swing from naphtha to distillate production and make up those differences. This swings 0.355 MMb/d or 27% of GO HCU capacity from naphtha to distillate production.

Net changes in processing for this 20/80 dilbit/current crude slate scenario boost coking and CCU feed rates by an estimated 0.340 and 0.396 MMb/d, respectively, but both processes remain within their nominal capacities while those rate increments achieve essentially zero net change in gasoline, diesel, and jet fuel feedstock.

In the +50% dilbit (50/50 dilbit/current slate) scenario, processing changes follow the same pattern but are larger with coking and CCU feed rates increasing by 1.138 and 0.723 MMb/d, respectively, and achieve similar net-zero changes in naphtha and distillate production, but at a coking rate that exceeds current capacity.

Total utilization of 2014 coking capacity is 128% for the 50/50 dilbit/current crude slate scenario in Table 5. This suggests that new conversion capacity would be built in the +50% dilbit scenario. That finding is consistent with refinery engineering knowledge—and, in fact, the coking capacity of US refineries has doubled since 1987.[34]

Results indicating < 100% utilization of capacity should be interpreted in the context of the capacity ‘optimization’ approach discussed in the methods section. New capacity could be built for various reasons, and if built, could be used at rates greater than those conservatively estimated in Table 5. For example, plants that lack DCU, CCU, or HCU capacity may build it instead of transferring intermediate products to other plants that have these capacities. Also, lower yields from boosting CCU recycle rates may force new capacity for the increased fresh feed rates needed to meet product targets. In any case, the differences in distillation properties from a switch to 20–50% more dilbit in the crude slate could require changes to pumps, exchangers, distillation unit internal configurations and piping, and other refinery equipment.

CCU coke yield increments estimated in Table 5 reflect increased feed rate *and* the increase in coke burn rate per barrel of CCU feed that would be driven by the lower quality of the new dilbit resid feed increments processed in CCUs. These increments represent a coke burn rate of ≈ 17.3 kg/b, based on the coke yield of 10.3 wt. % in Table 2 and the average density of the dilbit resid (1,055 kg/m^3; *SI Table S1*). This compares with ≈ 10.3 kg/b for current ‘baseline’ coke yield (7 wt. %) and HGO feed (≈ 922 kg/m^3; *SI Table S2*). Thus, the dilbit scenarios would result in burning ≈ 68% more catalyst coke per barrel for the new feed processed by CCUs. Emissions per barrel of the new CCU resid feed would be greater than baseline emissions per barrel by this amount, on average. Emission per barrel estimates applied to the new CCU resid feed increments are shown in Table 6.

Results for emission increments in the dilbit scenarios are summarized in Table 7. Volatile pollutant emissions from decoking operations exposing larger throughputs to the atmosphere at DCUs in US refineries could increase by ≈ 14% in the +20% dilbit scenario and by ≈ 47% in the +50% dilbit scenario. This estimate is based on the 0.340–1.138 MMb/d increments over the 2.303 MMb/d current feed rate shown in Table 5, conservatively scaled downward to the portion of total coking capacity represented by DCUs (94.6%). Estimated average benzene and volatile organic compound (VOC) emission increments for US refinery DCUs are based on these scaled increments applied to the DCU emission-per-barrel rates in Table 3. Benzene emissions from the DCUs could increase by an estimated 46–95 metric tons per year (t/yr) in the +20% dilbit scenario and by 150–320 t/yr in the +50% dilbit scenario. VOC emissions from the DCUs could increase by an estimated 7,400–15,300 t/yr in the +20% dilbit scenario and by 24,700–51,100 t/yr in the +50% dilbit scenario. These pollutant-specific DCU increments are based on a conservative interpretation of

Table 5. Estimated changes in conversion processing to maintain US gasoline, diesel and jet fuel production in scenarios with 20–50% more dilbit entering the current US crude slate.

Values in millions of barrels per day (MMb/d) or as noted

	20/80 dilbit/current scenario	50/50 dilbit/current scenario
Change in crude dist. unit (CDU) yield		
Naphtha, change from crude distillation	0.032	0.079
Distillate, change from crude distillation	–0.328	–0.820
Gas oil, change from crude distillation	–0.267	–0.669
Resid, change from crude distillation	0.615	1.538
Changes in coking rate and yield		
Net change in coking feed rate	0.340	1.138
Change in coker naphtha yield	0.065	0.216
Change in coker gas oil (GO) yield	0.153	0.512
Change in GO from CDU + coking	–0.114	–0.157
Change in resid from CDU + coking	0.275	0.400
Changes in CCU rate and yield		
Change in CCU fresh feed input	0.161	0.243
Change in CCU recycle rate	0.235	0.480
New resid feed % of total CCU fresh feed	5.5%	7.9%
Equivalent times new resid feed is recycled	0.86	1.20
Net change in CCU total feed rate	0.396	0.723
Change in CCU naphtha yield	0.202	0.369
Change in CCU distillate yield	0.083	0.152
Change in CCU coke yield (MM kg/day)	6.84	12.5
Change in CDU+coking+CCU naphtha	0.299	0.664
Change, CDU+coking+CCU distillate	–0.245	–0.668
Changes in GO-HCU rate and yield		
Net change in HCU GO feed input	0.000	0.000
Δ in GO-HCU feed input for naphtha	–0.355	–0.970
Δ in GO-HCU feed input for distillate	0.355	0.970
Change in GO HCU naphtha yield	–0.216	–0.592
Change in GO HCU distillate yield	0.245	0.669
Net changes in processing and key yields		
Coking capacity in 2014 (MMb/cd)	2.687	2.687
Coking feed rate in 2013 (MMb/d)	2.303	2.303
Net Δ in coking feed rate (MMb/d)	0.340	1.138
Total utilization of 2014 capacity (%)	98%	128%
CCU capacity in 2014 (MMb/cd)	5.616	5.616
CCU feed rate in 2013 (MMb/cd)	4.811	4.811
Net Δ in CCU feed rate (MMb/d)	0.396	0.723
Total utilization of 2014 capacity (%)	94%	98%
GO-HCU capacity, 2013 (MMb/cd)	1.297	1.297
GO-HCU feed swung to distillate (%)	27%	75%
Naphtha (gasoline feedstock)		
Net Δ from CDU, coking, CCU and HCU	0.082	0.072
Net Δ *v.* baseline CDU yield (%)	2%	2%
Distillate (diesel, jet fuel feedstock)		
Net Δ from CDU, coking, CCU and HCU	0.000	0.001
Net Δ *v.* baseline CDU yield (%)	0%	0%

Data from tables 1 and 2, except current process capacities and rates from refs. 31, 33, 34. *See* SI Table S1–S7 for details.

Table 6. Catalytic cracking unit (CCU) potential emission rates estimate for dilbit oil increments.

Emissions per barrel (b) of CCU feed

		Lower bound	Upper bound
Fine particulate	(g/b)	3.43	8.89
Chromium	(μg/b)	266	409
Lead	(μg/b)	219	478
Manganese	(μg/b)	463	976
Nickel	(μg/b)	810	6,110
Mercury	(μg/b)	38.4	111

Based on data from Table 4, 10.3 wt. % coke yield for denser 1,055 kg/m^3 resid feed; rates for resid feed increments only.

the limited available data from direct measurements of DCU emissions and are subject to the caveats regarding the available DCU data discussed in the methods section.

CCU emissions from US refineries could increase by an average of ≈ 14% in the +20% dilbit scenario and by an average of ≈ 25% in the +50% dilbit scenario. These increments are based on burning more coke in CCUs and are estimated based on the coke yields in Table 5 and that calculated from the baseline data cited above at the 4.811 MMb/d baseline feed rate in Table 5. *(SI Table S6.)* Changes in CCU feed volume and coke yield account for ≈ 59% and 41% of these increments, respectively. *(Id.)* CCU emission increments for specific pollutants are based on the emission-per-barrel rates in Table 6 and the CCU dilbit scenario feed rate increments in Table 5.

Average US refinery CCU emissions of condensable particulate matter could increase by 500–1,300 t/yr in the +20% dilbit scenario and by 900–2,400 t/yr in the +50% dilbit scenario. For metals, these estimates suggest that average US refinery CCU emissions could increase, in the +20% and +50% scenarios, respectively, by 38–59 and 70–110 kg/yr for chromium, by 32–69 and 58–130 kg/yr for lead, by 67–140 and 120–260 kg/yr for manganese, by 120–880 and 210–1,600 kg/yr for nickel, and by 5.5–16 and 10–29 kg/yr for mercury.

Because they are based on changes in the processes generating volatile chemical emissions from DCUs and coke combustion product emissions from CCUs, the relative percent increments in Table 7 also apply to the (large) subsets of those pollutants that are not yet quantified well by direct measurements of these emissions. At least 114 toxic chemicals have been identified in DCU emissions, CCU emissions, or both. *(SI Table S9.)*

Discussion

This work confirms that replacing more of the current US refinery crude slate with 'tar sands' dilbit oil has the potential to increase emissions of air pollutants that have local and regional environmental health implications from delayed coking and catalytic cracking units. DCUs and CCUs would process denser and lower quality oils in greater amounts, boosting the amounts of volatile chemicals entering the air from decoking and the amounts of combustion products from burning more coke in CCUs.

Table 7. Potential increase in delayed coking and catalytic cracking unit emissions estimated for scenarios in which 20–50% of the baseline US crude slate is replaced by tar sands dilbit oil.

Increments in percent and mass rate

		20/80 dilbit/current scenario	50/50 dilbit/current scenario
Delayed Coking			
Emission increment	%	+ 14 %	+ 47 %
Benzene	tons/yr	46 — 95	150 — 320
Volatile organic carbon (C_{2+})	tons/yr	7,400 — 15,300	24,700 — 51,100
Catalytic Cracking			
Emission increment	%	+ 14 %	+ 25 %
Particulates (condensable)	tons/yr	500 — 1,300	900 — 2,400
Chromium	kg/yr	38 — 59	70 — 110
Lead	kg/yr	32 — 69	58 — 130
Manganese	kg/yr	67 — 140	120 — 260
Nickel	kg/yr	120 — 880	210 — 1,600
Mercury	kg/yr	5.5 — 16	10 — 29

Total increments from these units at U.S. refineries—individual plant emissions will vary. DCU increments from greater decoking throughputs. CCU increments from greater coke-burn rates caused by increased feed rates and coke yields. *See* SI for details.

Direct measurement data are limited, especially for DCUs, but available data suggest that these emission increments would be significant. Benzene increments estimated for the US fleet of DCUs are 9–18% of benzene emissions reported from all US refinery sources by the Toxic Chemical Release Inventory *(SI Table S15)* in the +20% dilbit scenario and 29–62% of that TRI estimate in the +50% dilbit scenario. Emission increments reported here are US averages—individual plant emissions will vary—but if these VOC and cPM increments were realized at a 'notional' refinery with a 50,000 b/d DCU and 80,000 b/d CCU *(SI Table S16),* the resultant emissions could exceed the environmental significance thresholds applied in the San Francisco Bay Area (10 short tons/yr) for both pollutants.

Future work should consider feedstock-driven emissions from other refinery sources. The diluents in dilbit could boost volatile 'fugitive' emissions from crude oil storage tanks in amounts that, DIAL measurements suggest,[19] may be underestimated by traditional emission modeling. Substantial CO_2 emission from hydrogen production for the extra gas oil hydrocracking and hydrotreating needed to process bitumen has been documented,[6–10] but flaring from gas oil hydroprocessing warrants more attention. This exothermic, high pressure, hard-to-control process[21] can dump sulfur-rich gasses in amounts that overwhelm flare gas recovery systems when reactors depressure during upsets. Feedstock-driven expansion of gas oil hydroprocessing could thus increase the frequency and magnitude of flare emission incidents at refineries.

Emissions associated with DCU byproducts also warrant more attention. Most of the coke yield from DCUs is burned after it leaves the refinery gate,[22] much of it is exported overseas *(SI Table S8),* and coke by-production rises predictably as denser, higher sulfur crude is processed *(SI Table S17),* but the resultant emissions often are ignored by refinery and fuel cycle assessments. The byproduct gasses that are collected before venting starts in the decoking part of the DCU drum cycle are burned as fuel gas throughout refineries, and these coker gasses contain sulfur compounds that are uniquely resistant to the amine scrubbing typically used by refinery fuel gas systems.[23] Emissions from increased by-production of this 'dirtier' fuel gas as cokers process more resid should be considered in assessments of refining dilbit oils.

Ultimately, there are alternatives to refining bitumen, and the most important uncertainty in estimates of future emissions from refining more of this 'tar sands' oil involves public policy choices among these alternatives.

Acknowledgments

Funding for this work was provided by the Natural Resources Defense Council (NRDC). Brenda Shine and Eric Goehl of the US EPA generously assisted the author in accessing relevant public information.

Supporting Information Available

Data and details of methods; 34 pages including references and 17 annotated tables.

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Supplemental Information (SI) *for*

Toxic and fine particulate emissions from U.S. refinery coking and cracking of 'tar sands' oils

Greg Karras (2015)*

Thirty-four (34) pages including references and seventeen (17) annotated tables:

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Table S1. Feedstock quality data for diluted bitumen ('dilbit') oils.

Dilbits	**WCS**	**AWB**	**BHB**	**CDB**	**CL**	**KDB**	**Average**
Whole crude							
Density (kg/m^3)	929	923	925	924	928	927	926
Sulfur wt. %	3.5%	3.9%	3.7%	3.9%	3.8%	3.9%	3.8%
Distillation vol. fraction							
Gasses	0.024	0.015	0.016	0.012	0.016	0.015	0.016
Naphtha IBP–190C	0.197	0.279	0.276	0.274	0.230	0.246	0.250
Distillate 190–343C	0.174	0.113	0.107	0.123	0.152	0.122	0.132
Gas oil 343–527C	0.263	0.237	0.247	0.246	0.226	0.242	0.244
Resid 527+ °C	0.366	0.371	0.369	0.356	0.392	0.390	0.374
Cuts density (kg/m^3)							
Naphtha IBP–190C	690	688	681	687	688	672	684
Distillate 190–343C	880	882	892	880	883	892	885
Gas oil 343–527C	955	964	976	964	958	966	964
Resid 527+ °C	1,055	1,062	1,061	1,059	1,052	1,039	1,055
Cuts sulfur (wt. %)							
Naphtha IBP–190C	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	ND	<0.1%
Distillate 190–343C	1.3%	1.4%	1.5%	1.3%	1.6%	1.5%	1.4%
Gas oil 343–527C	2.9%	3.5%	3.6%	3.3%	3.3%	3.5%	3.4%
Resid 527+ °C	5.6%	6.5%	6.5%	6.2%	6.3%	6.0%	6.2%

Table S1 notes: Data shown were reported publicly by the Canadian oil industry for these crude streams, which are commercially available to US refiners. Dilbits, shown in the table by their acronyms, are: Western Canadian Select (WCS), Access Western Blend (AWB), Borealis Heavy Blend (BHB), Christina Dilbit Blend (CDB), Cold Lake (CL), and Kearl Lake (KDB). Data for distillation cuts are averages of the two most recent assays for each stream reported, where available; data for whole crude are averages for the most recent five-year period reported. *See* reference RS1, and Figure 2 in the main report for a graphic illustration of these data.

The densities, sulfur contents, and distillation yields of these oils are similar, reflecting the intentional blending of diluents—lighter cuts—with bitumen to facilitate transport of these commercial crude streams. Thus, differences from the average US crude slate (Table S2) would exist for these oils individually as well as on average. Blending with diluent also moderates the extreme density, contamination, and dearth of light yields from crude distillation that characterize the average pure bitumen (*RS2*). Volume expansion on distillation is ≈ 1%. Sulfur data were converted from wt. % to mass in calculating the weighted averages shown (this is because the same wt. % sulfur is a different mass of sulfur in an oil of different density).

Table S2. Feedstock data for the US refinery crude slate with comparisons to the Strategic Petroleum Reserve and observed feedstock processing.

	Current US crude slate	Strategic Pet. Reserve		Observed in 2013	
	Estimate (Est.)[a]	Data[b]	Δ from Est.	Data[c]	Δ from Est.
Whole crude					
Density (kg/m^3)	873	853	–2.3%	872	–0.1%
Sulfur wt. %	1.41%	0.89%	–36%	1.44%	–2.1%
Distillation vol. fraction					
Gasses	0.020	0.022	+10%		
Naphtha IBP–190C	0.240	0.290	+21%		
Distillate 190–327C	0.239	0.275	+15%		
Gas oil 327–566C	0.331	0.290	–12%	0.331	0.0%
Resid 566+ ºC	0.173	0.125	–28%	0.171	–1.1%
Cuts density (kg/m^3)					
Gas oil 327–566C	NR	922			
Resid 566+ ºC	NR	1,017			
Cuts sulfur (wt. %)					
Gas oil 327–566C	1.5%	1.3%	–13%		
Resid 566+ ºC	3.6%	2.3%	–36%		

Table S2 notes:

(a). The International Council on Clean Transportation (ICCT, 2013; *RS3*) estimated the current US crude slate for the year 2011 based on reported data for the major crude streams processed. The ICCT reported including data for domestic crude from the Bakken, Eagle Ford, Alaska, California and other sources; Canadian conventional and oil sands light, medium and heavy crude; and Mexican, Atlantic Basin, and rest-of-world light, medium, and heavy crude in this analysis *(Id.)*. Cut points shown in the table (e.g., 327–566 ºC for gas oil) are for the current US crude slate estimate *(Id.)*.

(b). The US Department of Energy (DOE) reported assays for pooled crude blends of the Strategic Petroleum Reserve (SPR) in 2002 *(RS4)*. Weighted averages of these 'pools' data are shown. Oils in SPR blends assayed included Isthmus, Iranian Light, Maya, Gulf of Suez Blend, Dubai Fateh, Arab Light, Alaska North Slope, Oman, Gabon Mandji, Ninian, Es Sider, Forties, Brent, Zarzaitine, Kole Marine, Sitica, Palanca, Oseberg, US Naval Reserve California (Stephens Zone), Bonny Light, Forcados, Ecofisk, Escravos, and Saharan Blend *(Id.)*.

The SPR oil appears lighter and lower in sulfur than the ICCT estimate for the current US refinery crude slate. In general, SPR crude quality is specified and managed for the ability of most US refiners to process it efficiently when needed *(Id.)*. The ongoing trend to denser, higher-sulfur crude feeds *(RS5)*, and refiners' incentive to run price-discounted lower quality oil when it can be processed efficiently, could explain these results suggesting a denser and higher-sulfur crude slate now than the blends acquired for the SPR before these 2002 DOE assays.

(c). The US Energy Information Administration (EIA) reported the volume (15.312 MMb/d; *RS6*), density (*RS5*), and sulfur content (*RS5*) of crude processed by US refiners in 2013. These data are used as current 'baseline' data herein. EIA does not report distillation properties of the US crude slate directly, however, it reports actual feed rates of 'downstream' processes that feed the gas oil and resid cuts from the crude slate actually processed. 'Observed' gas oil and resid fractions are based on these downstream feed observations for the US industry *(RS7–RS9)*. The sum of fresh feed inputs to delayed and fluid cokers (2.303 MMb/d; *RS7*) and production of asphalt and road oil (representing resid that is not converted in cokers; 0.322 MMb/d; *RS8*) in 2013 provides an indication of resid distillation yield.[1] Similarly, the sum of catalytic cracking and gas oil hydrocracking fresh feed (4.811 and 1.297 MMb/d; *RS7 and RS9*) minus gas oil yield from coking resid (≈ 1.036 MMb/d) provides an indication of 2013 gas oil distillation yield.[2] The 1.036 MMb/d subtracted is from coking, not distillation yield, and is estimated at the coker gas oil yield from Table S5 for resid feeds that are closest in density and sulfur content to the ICCT and SPR averages (45% vol. on coker feed; see Table S5).

The estimate values for properties of the 2011 US crude slate by the ICCT compare well to the observed values for actual operations in 2013 reported by EIA. See Table. Measured as percent change from the ICCT values, observed values are within ≈ 0.1% for crude density (872 v. 873 kg/m^3), within ≈ 2.1% for crude sulfur content (1.44 v. 1.41 wt. %), identical within ≈ 0% for gas oil distillation yield (0.331 volume fraction on crude), and within ≈ 1.1% for residuum yield (0.171 v. 0.173 vol. fraction). This close agreement of estimated and observed values supports the ICCT distillation properties estimate as reasonably representative of the current (2011–2013) 'baseline' US crude slate.

[1] Calculated as (2.303 + 0.322) / 15.312 = 0.171 (the volume fraction of 2013 crude input for resid yield).
[2] Calculated as (4.811 + 1.297 – 1.036) / 15.312 = 0.331 (the vol. fraction of 2013 crude for gas oil yield).

Table S3. Estimation details for crude slate blends and potential changes in crude distillation yields in 20/80 and 50/50 dilbit/baseline blend scenarios.

Volume in millions of barrels per day (MMb/d)

	Baseline slate[a]		Dilbit[b]	20/80 dilbit/ baseline[c]			50/50 dilbit/ baseline[c]		
	fraction	MMb/d	fraction	dilbit	base	slate	dilbit	base	slate
Crude vol.	1.000	15.312	1.000	3.062	12.250	15.312	7.656	7.656	15.312
d (kg/m^3)	872	872	926	926	872	883	926	872	899
sulfur (wt %)	1.44%	1.44%	3.8%	3.8%	1.44%	1.9%	3.8%	1.44%	2.6%
Cuts vol.									
Gasses	0.020	0.306	0.016	0.050	0.245	0.295	0.126	0.153	0.279
Naphtha	0.240	3.675	0.250	0.767	2.940	3.707	1.917	1.837	3.754
Distillate	0.239	3.660	0.132	0.404	2.928	3.332	1.010	1.830	2.840
Gas oil	0.331	5.068	0.244	0.746	4.055	4.801	1.865	2.534	4.399
Resid	0.173	2.649	0.374	1.145	2.119	3.264	2.863	1.325	4.188

Table S3 notes:

Crude slate volume (15.312 MMb/d) is reported 2013 US volume *(RS6)*. (a) Current US crude slate fractions from Table S2 are applied to 100% of crude slate volume to derive these 'baseline' values. (b) Average dilbit fractions from Table S1 are applied to 20% and 50% of this crude volume in the 20/80 and 50/50 dilbit/baseline scenarios, respectively. (c) The remaining volume of the current crude slate is 80% and 50% in the 20/80 and 50/50 dilbit/baseline scenarios, respectively. These columns in the table show the resultant volumes of dilbit and current crude that are added together to arrive at the cut volumes for each scenario, and the distillation yield of the total crude slate in each scenario. The +20–50% dilbit scenario crude densities (kg/m^3) and sulfur contents (wt. %) are weighted averages calculated from the 'dilbit' and 'base' column crude data for each scenario.

Some of the volumetric differences in yields indicated in the table are dramatic. Distillate yields are ≈328,000–820,000 barrels/day lower than the current US crude slate yield and resid yields are ≈615,000–1,538,000 b/d higher than that baseline yield in the +20–50% dilbit scenarios. Crude distillation naphtha yields are ≈32,000–79,000 b/d higher, and gas oil yields from crude distillation are ≈267,000–669,000 b/d lower in the +20–50% dilbit scenarios. Supplying current product markets at rate despite these large differences in distillation yield would require changes to process operations and equipment in many and perhaps virtually all parts of existing refineries. Conversion (cracking) processes, the focus of this analysis, are addressed in tables S4–S7.

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The data in Table S3 may represent a conservative estimate of actual distillation differences, in part because of differences between dilbit and current slate data with regard to the cut points used to generate the available distillation data. *See* tables S1 and S2. Using identical crude distillation cut points would likely further amplify the difference in distillation yields, especially for mid-barrel distillates, which have a more generous cutpoint range in the dilbits data reported than in the US crude slate data reported.

Table S4. Oil feed capacities and actual feed rates reported for US coking, catalytic cracking, and hydrocracking units, 2011–2014.

Volume in millions of barrels/day (MMb/d)

	2011		2012		2013		2014	
	CD[a]	SD[a]	CD[a]	SD[a]	CD[a]	SD[a]	CD[a]	SD[a]
Coking[b–d]								
Delayed coking cap.	2.307	2.487	2.410	2.578	2.451	2.692	2.542	2.773
Fluid coking capacity	0.145	0.159	0.145	0.159	0.145	0.159	0.145	0.159
Delayed & fluid cap.	2.453	2.646	2.555	2.737	2.596	2.851	2.687	2.932
Fresh feed input	2.094		2.177		2.303		NR	
Catalytic cracking[b,c]								
Fresh feed capacity	5.794	6.220	5.611	6.032	5.682	6.089	5.616	6.032
Recycle capacity		0.096		0.085		0.084		0.076
Fresh feed input	4.952		4.901		4.811		NR	
Hydrocracking[b–d]								
Distillate feed capacity	0.484	0.540	0.543	0.596	0.559	0.621	0.633	0.686
Gas oil feed capacity	1.081	1.170	1.070	1.161	1.230	1.337	1.297	1.400
Resid feed capacity	0.123	0.145	0.094	0.122	0.098	0.122	0.105	0.122
Total HCU capacity	1.688	1.855	1.707	1.879	1.887	2.080	2.035	2.208
Fresh feed input	1.467		1.529		1.670		NR	

Table S4 notes: (a) Capacities are shown in two ways: stream day (SD) capacity is the amount of input that can be processed in 24 hours when running at full capacity under optimal crude and product slate conditions with no allowance for downtime. Calendar day (CD) capacity is the amount that can be processed under usual operating conditions in 24 hours, accounting for the capabilities of a refinery's interconnected processing (e.g., "bottlenecks"), the types and grades of inputs processed, environmental constraints, and downtime. (b) Observed fresh feed input rates were reported through 2013 by the US Energy Information Administration (EIA), in its *U.S. Downstream Processing of Fresh Feed Input (RS7)*. (c) Catalytic cracking capacity data, and stream-day capacities for the other processes are from EIA's *U.S. Number and Capacity of Petroleum Refineries (RS10)*. (d) Calendar-day coking and hydrocracking capacities are from EIA's *Refinery capacity data by individual refinery as of Jan. 1 (RS9)*.

Delayed coking units (DCUs) and catalytic cracking units (CCUs) dominate US refinery conversion capacity. DCU capacity is ≈ 17 times fluid coking capacity, and CCU capacity is 4–5 times hydrocracking (HCU) capacity for gas oil feeds. Process capacity is not fully utilized. Comparisons of 2014 unit capacities with 2013 unit input baseline conditions indicate that 0.384

MMb/d, 0.805 MMb/d, and 0.365 MMb/d of available coking, CCU, and total HCU calendar-day capacity, respectively, is currently not utilized.

Note that the CCU recycle capacity data in Table S4 are incomplete. At least 25 CCUs were reported to EPA as having CCU resid recycle capacity *(RS11)* that were still operating in 2014 as reported to EIA *(RS9)* but were not reported to EIA as having any recycle capacity *(RS9)*. The resid recycle capacity for those 25 CCUs reported to EPA *(RS11)* but not to EIA in 2014 *(RS9)* (≈ 0.174 MMb/d) exceeds the *total* CCU recycle capacity EIA reported that year. Taken together, these data suggest a current CCU recycle capacity of ≈ 0.250 MMb/d,[3] however, publicly reported EPA data do not include recycle rates for many CCUs, and some of those units report recycle capacity to EIA, so this (250 MMb/d) figure also may underestimate total current US recycle capacity.

[3] Based on the *additional* EPA CCU reports, EIA 2014 data, and 0.076 + 0.174 = 0.250 MMb/d.

Table S5. Design capacity data for delayed coking unit (DCU), catalytic cracking unit (CCU), and gas oil hydrocracking unit (HCU) oil feeds and yields.

Delayed coking[a]

Feed API and wt % sulfur	17.1 API, 0.5%	12.8 API, 0.6%	8.2 °API, 3.4%	4 °API, 5.3%
Yield (vol. fraction)				
LPG	0.11	0.10	0.14	0.16
Naphtha	0.22	0.21	0.19	0.24
Gas oil	0.52	0.60	0.45	0.30
Coke	0.15	0.09	0.22	0.30

Catalytic cracking[b]

Feedstock	UR	UR	UR	UR	HGO	UR	UR	HGO	UR
Density (°API)	24.1	22.8	22.3	21.3	20.1	19.2	18.2	15.1	13.4
Sulfur (wt. %)	0.8	NR	1.0	NR	0.5	NR	1.1	3.3	1.3
Yield (vol. %) (wt. %)									
Naphtha	61	59	60	57	58	56	49	51	46
Distillate	17	16	17	15	18	16	20	21	19
Gas oil/heavy cycle oil	5.6	6.2	6.6	9.0	NR	9.6	5.9	NR	11
Resid	NR	NR	NR	NR	7.2	NR	NR	9.7	NR
Coke	7.1	8.4	7.8	9.1	7.0	10.8	5.9	10.3	7.6

Gas oil hydrocracking[c]

	Feedstock: 340–550 °C Straight-run vacuum gas oil; 22°API, 2.5 wt. % sulfur		
HCU product objective:	Naphtha	Jet Fuel	Diesel
Yield (vol. % fresh feed)			
Butanes	11	8	7
Pentanes	25	18	16
Naphtha	90	29	21
Distillate	—	69	77

Table S5 notes: (a) Available delayed coking unit (DCU) data are from Meyers, 1986 *(RS12)*. Mass/volume yield conversions used naphtha and gas oil API reported by Meyers and densities of 539 and 967 kg/m^3 for LPG and coke, respectively, from Karras, 2010 *(RS13)*. DCU yields follow the expected trend of increasing byproducts (gasses and coke) and decreasing liquids (naphtha+gas oil) with increasing feed (resid) density and sulfur. Sulfur content of the 8.2 °API feed shown (3.4%) is close to that of resid in the baseline shown in Table S2 (3.6%), and its density (8.2 °API ≈ 1,013 kg/m^3) is close to that of resid in the average SPR crude (1,017 kg/m^3). The 8.2 °API, 3.4% sulfur yield was chosen as representative for the analysis herein. This results in conservative coker yield estimates because the baseline crude slate is denser than the SPR average, and dilbit resid density and sulfur content are greater still.

(b) Available catalytic cracking unit (CCU) yield data are from Speight, 2013 *(RS14)*. UR: Unspecified resid feed. HGO: Heavy gas oil with an initial boiling point of 370 ºC. Yields shown in red are in wt. %. CCU yields also follow expected trends with feed quality; naphtha yields generally decline and coke yields increase as CCU feed becomes denser and higher in sulfur. Data for the 20.1 API/0.5% sulfur and 15.1/3.3% sulfur yields are more complete then those for the other yields (which lack feed cut-point, and in many cases, sulfur content data), and are the most representative of US refineries on average, because unlike the other data, these data are for fluid catalytic cracking *(RS14)*. FCCUs are the most common type of CCU in the US.

Sulfur in the 20.1 API feed (0.5%) is lower than in GO distilled from the baseline crude slate shown in Table S2 (1.5%), but its density (20.1 API ≈ 933 kg/m^3) is high relative to GO distilled from the average SPR crude shown in Table S2 (922 kg/m^3), and a portion of current US CCU feed is pretreated to lower its sulfur content *(RS11)*. Thus, the 20.1 API/0.5% sulfur yield shown provides the most representative available data for baseline average US CCU yield. The 15.1 API (≈ 965 kg/m^3), 3.3% sulfur feed is very close to the average GO distilled from dilbits (964 kg/m^3, 3.4 wt. % sulfur). The data for this HGO feed are the most representative available for CCU yield from US refining of additional dilbit, and are used in the scenario analysis herein. This results in conservative estimates of potential CCU yield because CCUs would process more resid blended with HGO in these scenarios, there is relatively little CCU *resid* pretreatment capacity in the US, and this relatively high CCU distillate yield (21 vol. %) may underestimate the processing impacts of low distillate yield from dilbit crude distillation (*see* tables S1, S2).

(c) Available hydrocracking unit (HCU) data are from Robinson and Dolbear, 2007 *(RS15)*. First, note the volume expansion from aggressive hydrogen addition in the cracking process (yields substantially exceed 100% of feed volume). Equally important, different HCU yields result from the same HGO feed when the HCU is operated for different product objectives. This ability to 'swing' from making naphtha for gasoline to making distillate for diesel or jet fuel is used to supply seasonally changing product demand and explains in part why substantial HCU capacity has been built despite its relatively high capital and operating costs *(RS15)*. Indeed, investment in HCU capacity has been called a 'stay in business' cost for some refiners *(Id.)* HCU capacity to swing from naphtha to distillate production would be used to mitigate the low crude distillation distillate yield from replacing more of the US crude slate with dilbit (Table S3), especially since DCU and CCU capacity is available to make up the lost HCU naphtha yield (tables S4, S5). The HCU 'Jet Fuel' yield estimate in Table S5, which conservatively minimizes the amount of HCU naphtha yield lost in such a swing, is used by the analysis herein.

Table S6. Estimate calculation for changes in DCU and CCU feed rate and CCU coke burn in 20/80 and 50/50 dibit/baseline US crude feed scenarios.[a]

Scenario	20/80 dilbit/baseline crude blend	50/50 dilbit/baseline crude blend
Change in DCU cycle number, volume, or both		
Baseline feedrate (MMb/d)[b]	2.303	2.303
Feed increment (MMb/d)[a,c]	0.340	1.138
DCU increment (MMb/d)[d]	0.322	1.076
DCU rate increase (%)	14%	47%
Change in CCU yield and combustion of catalyst coke		
2013 fresh feed (MMb/d)[b]	4.811	4.811
2013 recycle feed (MMb/d)[b]	0.084	0.084
Baseline feedrate (MMb/d)	4.895	4.895
Feed increment (MMb/d)[a,c]	0.396	0.723
CCU coke burned		
2011–2013 (M tons/d)[e]	50.2	50.2
Feed increment (M t/d)[e]	6.84	12.5
Cokeburn rate increase (%)	14%	25%

Table S6 notes: (a) Based on cracking process changes due to dilbit scenario shifts in crude distillation from distillate and gas oil (GO) to resid that would be needed to maintain gasoline, diesel, and jet fuel feedstock production at the current baseline crude rate, and the data in tables S1–S5 and S7. Scenario process flows and rates are detailed and tabulated in the main report. Briefly, available conversion capacity (Table S4) would be utilized before building new capacity; DCUs would convert more resid to naphtha and GO (Table S5); CCUs would convert more resid and GO to naptha and distillate (*Id.)*; and the new DCU and CCU naphtha would allow GO HCUs to swing from naphtha to distillate (*Id.)* until these rate changes and shifts produce naphtha and distillate at baseline volume rates from the new crude blend.

(b) Feed rates for DCU and CCU fresh feed and CCU recycle feed in 2013 from Table S4.

(c) Additional DCU fresh feed resid and CCU fresh feed and recycle feed gas oil and resid increments under scenario conditions described in note "a" and detailed and tabulated in the main report. Crude distillation yields at current crude rate are ≈ 0.328–0.820 MMb/d and 0.267–0.669 MMb/d lower in distillate and gas oil, respectively, and ≈ 0.032–0.079 and 0.615–1.538 MMb/d higher in naphtha and resid, respectively, in the +20–50% dilbit scenarios. (Table S3.) Even after swinging 27% of gas oil HCU capacity to distillate yield, coking must run near capacity on increased resid and shift 0.275 MMb/d of resid (≈ 5% of CCU runs) to be blended into CCU feed; and CCU rate increases to 94% of capacity, recycling an additional 5% of CCU feed, to maintain naphtha and distillate production in the +20% dilbit scenario. In the +50% dilbit scenario 75% of GO HCU capacity swings to distillate, coking rate exceeds current capacity by ≈ 28%, and recycling 0.48 MMb/d more CCU feed than in the baseline (recycling new CCU resid feed ≈ 1.2 times) increases total CCU feedrate to ≈ 98% of 2014 CCU capacity.[4] These estimates are based on the changes in crude distillation yields from Table S3 stated above, the unit rate and capacity baselines from Table S4, and the conversion yields from Table S5.[5] Process rate and feed/product flows maintaining the scenario crude and product slate conditions as described in note "a" are detailed and tabulated in the main report.

(d) DCU portion of the total coking capacity as of 2014 (94.6%) from data in Table S4.

(e) Coke yield per barrel CCU feed would increase because dilbit GO and resid is denser and more contaminated (tables S1, S2), and CCUs would run more recycle resid of even lower quality (this table). The 7 wt. % (baseline) and 10.3 wt. % (scenarios) feed-related coke yields from Table S5 are applied to the amount of CCU throughput equal to the baseline, and to the incremental CCU throughput exceeding the baseline, respectively. The total throughput amount up to baseline (4.895 MMb/d) is further assumed to remain at baseline density as represented by the SPR average from Table S2 (922 kg/m^3) while only the portion of the new CCU resid feed in the increment exceeding baseline is represented by the dilbit resid from Table S1 (1,055 kg/m^3). Thus, the coke yield/barrel increase is conservatively applied only to the new increments of CCU feed. This estimate is conservative, also, because the resid that CCUs would run in greater amounts is of lower quality than the gas oil the 0.7–10.3% coke yield data are based upon, so that running this additional resid throughput could further boost CCU coke yield. This estimate implies adjusting baseline emissions per barrel CCU feed by a factor of ≈ +0.69.

CCU feed rate change and coke-burn (mass/b) change components account for ≈ 59% and 41%, of the estimated potential CCU coke combustion emissions increments, respectively.

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[4] Note that HCU rate could increase instead of CCU rate, but at greater capacity addition cost, as explored in Table S7 below.

[5] Table S5 yields, as vol. % on feeds: DCU yields, 19% and 45% for naphtha and gas oil; CCU yields, 51% and 21% for naphtha and distillate; HCU yields (accounting for capacity swung from naphtha to distillate production target), –61% and +69% for naphtha and distillate, respectively.

Table S7. Estimate of additional conversion capacity costs to maintain US gasoline, diesel, and jet fuel production by a coking and *hydrocracking* alternative.

Values in millions of barrels per day (MMb/d) or percent (%)

Scenario	**20/80 dilbit/baseline crude blend scenario**	
Case	**A: Use existing capacity 1st**	**B: DCU & GO HCU alternative**
Change in crude dist. unit (CDU) yield[a]		
Naphtha, change from crude distillation	0.032	0.032
Distillate, change from crude distillation	–0.328	–0.328
Gas oil, change from crude distillation	–0.267	–0.267
Resid, change from crude distillation	0.615	0.615
Changes in coking rate and yield		
Net change in coking feed rate[b]	0.340	0.615
Change in coker naphtha yield[c]	0.065	0.117
Change in coker gas oil (GO) yield[c]	0.153	0.277
Change in GO from CDU + coking	–0.114	0.010
Change in resid from CDU + coking	0.275	0.000
Changes in CCUs rate and yield		
Change in CCU fresh feed input[b]	0.161	—
Change in CCU recycle rate[d]	0.235	—
New resid feed (% total CCU fr. feed)[d]	≈5.5%	—
Eq. times new resid feed is recycled[d]	0.855	—
Net change in CCU total feed rate[d]	0.396	0.000
Change in CCU naphtha yield[c]	0.202	—
Change in CCU distillate yield[c]	0.083	—
Change in CDU+coking+CCU naphtha	0.299	0.149
Change, CDU+coking+CCU distillate	–0.245	–0.328
Changes in GO-HCU rate and yield		
Net change in HCU GO feed input[e]	0	0.010
Δ in GO-HCU feed input for naphtha[e]	–0.355	–0.465
Δ in GO-HCU feed input for distillate[e]	0.355	0.475
Change in GO HCU naphtha yield[c]	–0.216	–0.284
Change in GO HCU distillate yield[c]	0.245	0.328
Net changes, processing and key yields		
US coking capacity in 2014 (MMb/cd)[f]	2.687	2.687
US coking feed rate in 2013 (MMb/d)[f]	2.303	2.303
Net Δ in coking feed rate (MMb/d)	0.340	0.615
Total utilization of 2014 capacity (%)	98%	109%
US CCU capacity in 2014 (MMb/cd)[f]	5.616	5.616
US CCU feed rate in 2013 (MMb/cd)[f]	4.811	4.811
Net Δ in CCU feed rate (MMb/d)	0.396	0.000
Total utilization of 2014 capacity (%)	94%	86%
US HCU capacity in 2014, (MMb/cd)[f]	2.035	2.035
US GO-HCU capacity, 2013 (MMb/cd)[f]	1.297	1.297
Net Δ in GO-HCU feed rate (MMb/d)	0	0.010
Δ in GO-HCU feed swung to distillate	0.355	0.465
Naphtha (gasoline feedstock)		
Net Δ from DCU, coking, CCU and HCU	0.082	–0.135
Net Δ *v.* baseline CDU yield (%)	2%	–4%
Distillate (diesel, jet fuel feedstock)		
Net Δ from DCU, coking, CCU and HCU	0.000	0.000
Net Δ *v.* baseline CDU yield (%)	0%	0%

Figures may not add due to rounding. *See* Table S7 notes, *next page.*

Table S7 notes:

(a) Data from Table S3. (b) Cokers and CCUs process resid; CCUs and GO HCUs process gas oil. The change in CCU fresh feed is the net change from CDUs and coking, minus any new GO fed to HCUs. (c) From yields on feed vol. identified in Table S5: DCU naphtha (19%) and gas oil (45%); CCU naphtha (51%) and distillate (21%); GOHCU (naphtha/dist–'jet' / swing to distillate 'jet'): naphtha (90% / 29% / –61%) and distillate (0% / 69% / +69%).

(d) These Case A CCU rate increments are based on replacing naphtha production lost from CDUs (after coker yield is accounted for) and from GO HCUs that swing to distillate; future CCU recycle rates are not objectively known. However, the CCU process has the capability to feed resid and clearly would recycle some of its residue and GO to crack more light product. (*RS12–RS15.*) Case 'A' recycle rates are ≈ 5.5% and 7.9% of CCU fresh feed in the +20% and +50% dilbits scenarios, respectively, and represent recycling ≈ 16–17% more of the *new* resid feed volume back into CCUs the equivalent of 0.86–1.2 times in the +20–50% dilbit scenarios. The recycle rate increments appear reasonable—and may be achievable without capacity addition in the +20% dilbit scenario, based on public reports that each omit recycle data from some CCUs.[6] In any case, total (fresh+recycle) feed is 94%–100% of 2014 CCU fresh feed capacity in Case A +20–50% dilbit scenarios, supporting these results.

(e) In Case A, GO HCUs stay below current capacity but make more GO into distillate instead of naphtha, and achieving baseline distillate volume drives this swing (while CCU rate increases to balance naphtha at baseline, accounting for changes in CDU+coker+HCU yield. In Case B, there is no change in CCU operation or feed, and GO HCUs increase rate *and* swing from naphtha to distillate production seeking to balance naphtha and distillate at baseline (accounting for changes in CDU+coker+HCU yield).

(f) Fresh feed calendar-day capacities as of January 2014 from Table S4. Stream-day capacities are greater than calendar-day capacities, and CCU fresh+recycle feed capacities are greater than fresh feed capacities (Table 4). For this reason, from the standpoint of estimating potential needs for capacity additions, the capacity utilization results shown in the table based on fresh feed and c/d capacities may be conservative. Also note that 'net change' rates for CCUs,

[6] Based on 0.235 MMb/d (Table S7) *v.* 0.250 MMb/d based on two sources of incomplete data noted in Table S4.

including fresh *and* recycle feed changes, are compared with CCU fresh feed capacity that does not include recycle feed capacity,[7] so CCU capacity utilization results are conservative in this respect for another reason as well. Total coking capacity, including delayed and fluid coking, is shown; the scale of resid yield changes versus current coking capacities in some cases or scenarios strongly suggests all types of coking could increase rate in these scenarios, and in any case, data were not available to calculate DCU-specific capacity utilization in the US (e.g., EIA did not report DCU feed inputs publicly). Capacity for fresh feed of *gas oil* to hydrocracking (GO-HCU; ≈ 64% of total 2014 HCU capacity in Table 4) is used instead of total HCU capacity. In essence, this makes the assumption that HCUs designed for other types of feed (*esp.* hydrocracking of distillate feed; ≈ 31% of total 2014 HCU capacity in Table 4), would not be able to switch over or would not switch over to gas oil feeds—another potentially conservative assumption in the analysis. EIA did not report US feed rates for GO-HCUs publicly, so capacity utilization for GO-HCUs (separately from all HCUs) were not available.

Results support the 'analysis' case (Case A) as it may achieve product targets within existing DCU, CCU and HCU capacities while the HCU alternative (Case B) nearly achieves product targets only by clearly adding to existing coking capacity, even in the less extreme, +20% dilbit scenario. Because Case B assumes no change in CCU operation, coking must expand to run the excess resid from crude distillation of dilbit and to convert enough of the resid to GO so that GO-HCUs can make distillate *and* naphtha. But even coking all of the excess resid in the +20% dilbit scenario provides only ≈ 10,000 b/d more gas oil feed to the HCUs, not quite enough extra feed to meet both the distillate and the naphtha baseline targets in the Case B +20% scenario. In sum, adjusting all three types of conversion capacity provides more flexibility to convert the new crude slate, and it does not seem plausible that refiners would forego that existing flexibility and commit additional capital to capacity expansions that would not achieve superior product yields.

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[7] Data suggest CCU recycle capacity is underestimated and poorly quantified (<u>*see*</u> Table S4 notes, note 'd' above).

Table S8. US production and export data for selected refined products.

Annual data in thousands of barrels per day (Mb/d)

	Finished mtr. gasoline		Kerosene jet fuel		Distillate fuel oil		Petroleum coke	
	Production	Export	Production	Export	Production	Export	Production	Export
1983	6,338	10	817	5	2,456	64	420	195
1984	6,453	6	919	7	2,680	51	439	193
1985	6,419	10	983	12	2,686	67	455	187
1986	6,752	33	1,097	16	2,796	100	506	238
1987	6,841	35	1,138	23	2,729	66	512	213
1988	6,956	22	1,164	27	2,857	69	544	231
1989	6,963	39	1,197	23	2,899	97	542	233
1990	6,959	55	1,311	39	2,925	109	552	220
1991	6,975	82	1,274	39	2,962	215	568	235
1992	7,058	96	1,254	33	2,974	219	596	216
1993	7,304	105	1,309	43	3,132	274	619	258
1994	7,181	97	1,410	16	3,205	234	622	261
1995	7,459	104	1,407	23	3,155	183	630	277
1996	7,565	104	1,513	46	3,316	190	664	285
1997	7,743	137	1,554	35	3,392	152	689	306
1998	7,892	125	1,525	24	3,424	124	712	267
1999	7,934	111	1,565	29	3,399	162	713	242
2000	7,951	144	1,606	32	3,580	173	727	319
2001	8,022	133	1,529	29	3,695	119	767	336
2002	8,183	124	1,514	8	3,592	112	781	337
2003	8,194	125	1,489	20	3,707	107	798	361
2004	8,265	124	1,547	40	3,814	110	836	350
2005	8,318	136	1,546	53	3,954	138	835	347
2006	8,364	142	1,481	41	4,040	215	848	366
2007	8,358	127	1,448	41	4,133	268	823	366
2008	8,548	172	1,493	61	4,294	528	818	377
2009	8,786	195	1,396	69	4,048	587	799	391
2010	9,059	296	1,418	84	4,223	656	812	449
2011	9,058	479	1,449	97	4,492	854	843	499
2012	8,926	409	1,471	132	4,550	1,007	853	503
2013	9,234	373	1,499	156	4,733	1,134	871	524

Table S8 notes: Refinery and blender net production (*RS16*) and US exports (*RS17*) of finished motor gasoline, kerosene jet fuel, distillate fuel oil, and petroleum coke from US EIA. Production continues to grow or is stable, and exports have grown, especially in recent years, helping to explain continued production growth despite lower domestic demand for some of these products. While it is not possible to know future international demand or market conditions, these data support *forecasting* scenarios with the potential for stable US refinery gasoline, diesel, and jet fuel feedstock production.

Table S9. Toxic pollutants detected in EPA ICR source tests of DCUs and CCUs.

Pollutant	Detected from	Pollutant	Detected from
1,2–Dibromoethane	DCU and CCU	Fluorene	DCU and CCU
2,2,4–Trimethylpentane	DCU	Formaldehyde	DCU and CCU
2,4–Dimethylphenol	DCU and CCU	Hexane	DCU and CCU
2–Methylnaphthalene	DCU and CCU	Hexavalent chromium	CCU
2–Methylphenol	CCU	Hydrogen chloride	CCU and CCU
2–Nitropropane	DCU and CCU	Hydrogen cyanide	DCU & CCU
3–Methylcholanthrene	DCU	Hydrogen fluoride	CCU
Acenaphthalene	DCU and CCU	Hydrogen sulfide	DCU
Acenaphthene	DCU and CCU	Indeno(1,2,3–cd)pyrene	DCU and CCU
Acetaldehyde	DCU and CCU	Lead	DCU and CCU
Acetone	DCU and CCU	m&p–Xylenes	DCU
Acetonitrile	CCU and CCU	Manganese	DCU and CCU
Acrolein	DCU and CCU	Mercury (elemental)	DCU and CCU
Acrylonitrile	CCU	Mercury (oxidized)	DCU and CCU
Ammonia	CCU	Mercury (total)	DCU and CCU
Aniline	DCU and CCU	Methanol	DCU and CCU
Anthracene	DCU and CCU	Methyl iso–Butyl Ketone	DCU
Antimony	DCU and CCU	Methyl t–Butyl Ether (MTBE)	DCU
Arsenic	DCU and CCU	Methylene Chloride	DCU and CCU
Benzene	DCU and CCU	Naphthalene	DCU and CCU
Benzo(a)anthracene	DCU and CCU	Nickel	DCU and CCU
Benzo(a)pyrene	DCU and CCU	Nitric oxide	DCU
Benzo(b)fluoranthene	DCU and CCU	Nitrobenzene	DCU and CCU
Benzo(e)pyrene	DCU and CCU	o–Toluidine	DCU
Benzo(ghi)perylene	DCU and CCU	o–Xylene	DCU
Benzo(k)fluoranthene	DCU and CCU	Particulates (condensible)	DCU and CCU
Beryllium	DCU and CCU	Particulates (filterable)	DCU and CCU
Biphenyl	DCU and CCU	Particulates (total PM)	DCU and CCU
Cadmium	DCU and CCU	Pentane	DCU
Carbon disulfide	CCU	Perylene	DCU and CCU
Carbon monoxide	DCU and CCU	Phenanthrene	DCU and CCU
Chlorine	CCU	Phenol	DCU and CCU
Chlorine gas	DCU	Propanal	DCU and CCU
Chlorobenzene	DCU	p–Xylene	DCU
Chromium	DCU and CCU	Pyrene	DCU and CCU
Chrysene	DCU and CCU	Selenium	DCU and CCU
Cobalt	DCU and CCU	Styrene	DCU
Cresols	DCU and CCU	Sulfur dioxide	DCU and CCU
Cumene	DCU	Tetrachloroethane	DCU
Dibenzo(a,e)pyrene	DCU	Toluene	DCU and CCU
Dibenzo(a,h,)anthracene	DCU	PCBs (total)	CCU
Dibenzofuran	DCU and CCU	PCBs (dioxins)	CCU
Ethylbenzene	DCU	PC dibenzo–*p*–dioxins	CCU
Fluoranthene	DCU and CCU	PC dibenzofurans (dioxins)	CCU

Table S9 notes: Data from DCU and CCU source tests reported to and summarized by EPA in its ICR public data reports (*RS11; see* esp. Goehl, 2012 summaries of delayed coking unit and fluid catalytic cracking unit emission source test reports). Pollutants reported as detected in one or more test runs are included: note, however; the vast majority of pollutants detected were not measured above method detection limits in some—and typically most—of the total DCU or CCU source tests. 'Dioxins' listings in this table includes 29 polychlorinated dibenzo–*p*–dioxin, dibenzofuran, and biphenyl compounds with dioxin-like activity (binding to dioxin receptor). Including these 29 dioxins, 114 toxic chemicals were detected in these source tests.

Table S10. VOC, methane, and benzene emissions measured from DCU vents.

Site[a]	Marathon Garyville LA	BP-Husky Oregon OH	ExxonMobil Baytown TX	Houston Refining Houston TX	Hovensa St. Croix VI
Coker drums[a]	2	2	4	4	4
Unit capacity (Mb/d)	44.00[a]	27.00[a]	51.50[b]	82.87[c]	73.60[b]
Test rate (Mb/d)	38.00[d]	24.30[a]	46.35[e]	74.58[a]	59.66[a]
Full cycle hours[a]	34	33	28.25	22	40
Cycles/yr (all drums)[a]	515	531	1,240	1,593	876
VOC emissions					
Data flags[a]	—	—	—	—	—
kg/hour (avg.)	3.39	10.4	1.59	0.573	51.9
lb/day (avg.)	179	548	83.9	30.3	2,748
short tons/year	32.7	100	15.3	5.53	502
lb/Mb feed	4.72	22.6	1.81	0.407	46.1
lb/drum cycle[a]	127	377	24.7	6.95	1,145
Methane emissions					
Data flags[a]	—	—	—	—	—
kg/hour (avg.)	7.01	8.83	4.84	0.423	99.0
lb/day (avg.)	371	467	256	22.4	5,239
short tons/year	67.7	85.2	46.7	4.09	956
lb/Mb feed	9.77	19.2	5.52	0.300	87.8
lb/drum cycle[a]	263	321	75.3	5.13	2,183
Benzene emissions					
Data flags[a]	DLL	DLL	DLL	DLL	BDL
kg/hour (avg.)	0.0203	0.0522	0.0219	0.0010	< 0.5
lb/day (avg.)	1.07	2.76	1.16	0.05	< 26
short tons/year	0.196	0.504	0.211	0.010	< 5
lb/Mb feed	0.0282	0.114	0.0250	0.0007	< 0.4
lb/drum cycle[a]	0.760	1.90	0.341	0.0120	< 11

Table S10 notes:

BDL: Analyte below method detection level in all test runs; data not used in statistical analysis for comparison of these measurements of delayed coking (DCU) vent emissions with measurements of emissions from the decoking cycle. DLL: Analyte below method detection level in one or more test runs and above MDL in one or more runs; data used in comparison.

(a) Data from ICR source test; for emission data _see_ esp. Goehl (2012) summary of delayed coking unit emission source test reports (*RS11*). (b) Data from ICR 'Component 1' Non-CBI data tables (*RS11*). (c) Data from US EIA for this facility's b/cd delayed coking capacity in 2011 (*RS9*). (d) Estimated based on ICR Source Test Report at page 2-3 (*RS11*). (e) Estimated at 90% of capacity based on EPA ICR protocol requirement to test at a minimum of 90% capacity. Note that the ranges of emissions expressed on a per-barrel basis are generally similar to or smaller than those expressed on a per-cycle basis. This result was expected because coke cycle volume can affect emissions per cycle. VOC, methane, and benzene results of all ICR source tests reported are shown (only five source tests of DCUs were reported) and VOC, methane, and benzene were detected in 5, 5, and 4 of these tests respectively. Only DCU vent emissions were reported in the ICR data, however, volatile chemicals also emit during coke cutting and byproduct handling; when the coke drum is opened, when the coke is 'cut' from the drum, and when the coke, which can be 9–12% volatile chemicals, as well as the cutting and quench water, is handled (*RS18–RS20*).

Table S11. VOC, methane, and VOC emissions measured from DCU decoking.

Site	Canadian refinery[a,b]	Canadian refinery[a,b]
Coker drums[a]	2	2
Coker capacity (Mb/d)[b]	7.5	7.5
Test rate (Mb/d)[c]	7.5	7.5
Full cycle hours[d]	32 (range: 22–40)	32 (range: 22–40)
Cycles/yr (all drums)[d]	548 (range: 438–796)	548 (range: 438–796)
Emission sources	venting, coke cutting & coke water handling	venting and coke cutting
C_{2+} VOC (grams/b)		
Lower bound[e]	132	63.4
Median[f]	206	99.1
Upper bound[g]	480	231
Methane (grams/b)[h]		
Lower bound[e]	77.9	37.6
Median[f]	122	58.7
Upper bound[g]	283	137
Benzene (mg/b)[h]		
Lower bound[e]	810	391
Median[f]	1,266	610
Upper bound[g]	2,945	1,421

Table S11 notes: (a) Chambers et al., 2008 reported direct measurements of hydrocarbon emissions from a delayed coker at a Canadian refinery using differential absorption light detection and ranging (DIAL) technology. All parts of the decoking cycle were measured; samples were 2–3 hours each; at least 12 samples of the coking area are described (<u>*see*</u> Chambers Table 5); and validation demonstrations (+5% to –15%) and closeness of the results to the median from 16 other refinery DIAL surveys support their accuracy (*RS20*). C_{2+}VOC, methane, and benzene emissions from the coker venting, cutting and water handling operations averaged 206, 122, and 1.27 kg/hr, respectively (*RS20; <u>see</u>* also note h below). (b) Data from *Oil & Gas Journal* 'Worldwide Refining Survey' (*RS21*). These data (*RS21*) indicate that the only Canadian refinery operating at the crude and product capacities described by Chambers et al. (*RS20*) during their survey and publication had 7,500 b/cd of DCU capacity.[8] Note that the refinery measured used injection wells to handle some of its wastewater (*RS20*). Typical US refinery operations may differ from that approach; this difference is explored by breaking out water handling emissions from other DCU decoking emissions in Table S11. (c) Measurement during operation at 100% capacity is conservatively assumed. (d) Typical cycle times range from 28–36 hours (*RS18*) but the entire range from ICR data (22–40 hrs., median 32 hrs; *RS11*)

[8] <u>*See*</u> *RS21* data for Petro-Canada Products Ltd. Edmonton listing during 2005–2008.

is conservatively assumed. Emitting activities (vents, water drains, unheading, hydraulic decoking 'drilling' and purging) are also conservatively assumed—at the low emitting end of this range—to last only 4 hours, which is the lowest assumption consistent with Chambers et al.'s samples of venting *and* coke drilling samples at 2-hour-minimum sampling times (*RS20*). (e) Based on 40-hour cycle or 438 cycles/year with emission during 4 hours/cycle. (f) Based on 32-hour cycle or 548 cycles/year with emission during 5 hours/cycle. (g) Based on 22-hour cycle or 796 cycles/year with emission during 8 hours/cycle. (h) Methane and benzene emissions fractions from venting, coke cutting, and coke water handling based on VOC emissions breakdowns reported by Chambers et al. (*RS20*).

Table S12. Benzene, methane and VOC emissions measured from delayed coker units (DCUs).

Emissions per barrel (b) of coker oil feed

	Coker vents[a]		Vents & coke cutting[b]		Vents, cutting & proc. H_2O[b]	
	median	(range)	median	(range)	median	(range)
Benzene (mg/b)	19	(<1–52)	610	(390–1,400)	1,270	(810–2,900)
Methane (g/b)	11	(<1–40)	59	(38–140)	122	(78–280)
C_{2+} VOC (g/b)	7	(<1–21)	99	(63–230)	206	(130–480)

Table S12 notes: Data summarized from tables S10 and S11. Decoking emissions estimated from direct measurements of vents, coke cutting, and coker process water handling exceed those estimated from ICR source tests of vents alone by ≈ 1–2 orders of magnitude, especially for benzene. These results demonstrate the inaccuracy of relying solely on the vent emission measurements from the ICR source tests (Table S10) to estimate emissions of volatile chemicals from DCUs. Only a single DCU is represented, however, very conservative assumptions for the low-end and median emissions (Table S11) notes d–g compensate for this weakness in the data to the extent possible—especially for in the case of 'venting and coke cutting' estimates, which do not assume similar water handling emissions by the average US refinery DCU operation.

The low end of the 'vents & coke cutting' emissions, and the low end of the 'vents, cutting & process water' emissions (e.g., 390 and 810 mg/barrel, respectively, for benzene) are conservatively chosen to represent lower bound and upper bound DCU emissions herein.

Table S13. Concentrations of selected elements measured in a CCU emission stack.
Stack concentrations in micrograms per cubic meter (μg/m^3)

Antimony	0.41	Lanthanum	865
Arsenic	1.63	Lead	6.41
Beryllium	0.15	Nickel	819
Cadmium	2.92	Selenium	0.58
Cesium	0.04	Thorium	2.14
Chromium	962	Uranium	0.55
Cobalt	24.8	Vanadium	145

Table S13 notes: Data from Sánchez de la Campa et al., 2011 (RS22). Concentrations of beryllium, chromium, lanthanum, and uranium in the stack of this CCU in were the highest of those in any stack measured by this survey of a Spanish refinery and petrochemical complex (*Id.*) Metals in CCU emissions originate from both CCU catalysts (e.g., lanthanum; nickel) and from the oils fed to the CCUs (e.g., nickel; vanadium). Indeed, vanadium, nickel and lanthanum have been used tracers for CCU particulate emissions. This information provides ancillary support for the ICR source tests of CCU metal emissions.

Table S14. Emission data for toxic pollutants detected in source tests of multiple CCUs, with calculations for median and 90th Percentile emissions/barrel—page 1 of 2.

Site	ExxonMobil Torrance CA[a]	Chevron Kapolei HI[a]	Marathon Robinson IL[a]	BP Whiting IN[a]	Citgo Lake Charles LA[a]	Motiva Norco LA[a]	Flint Hills Rosemount MN[a]
Feed HTU	102 Mb/d[c]	0%[d]	0%[d]	89.1 Mb/d[c]	0%[d]	0%[d]	100%[d]
PM control	ESP[d]	ESP[d]	WS[d]	ESP & Inj.[d]	venturi/WS[d]	venturi/WS[d]	ESP[d]
Coke burn	NR	169[a]	310[d]	NR	314[a]	960[d]	451[a]
Capacity	83.5 Mb/d[f]	21.0 Mb/d[f]	54.45 Mb/d[d]	115 Mb/d[g]	49.0 Mb/d[d]	118.8 Mb/d[d]	81.0 Mb/d[d]
Test rate	75.15 Mb/d[h]	18.9 Mb/d[h]	49.01 Mb/d[h]	103.5 Mb/d[h]	52.42 Mb/d[a]	106.9 Mb/d[h]	74.23 Mb/d[a]
PM flags	no flags	no flags	no flags	no flags	no flags	no flags	NR
PM (lb/h)	22.1	6.13	31.2	22.7	4.23	43.5	
PM (g/b)	3.20	3.53	6.94	2.39	0.88	4.42	
cPM flags	no flags	no flags	no flags	no flags	no flags	no flags	NR
cPM (lb/h)	20.8	1.68	8.53	9.49	2.61	21.8	
cPM (g/b)	3.01	0.969	1.89	1.00	0.542	2.22	
PM lb/t coke		0.873	2.42		0.323	1.09	
cPM/PM (%)	94%	27%	27%	42%	62%	50%	
NH_3 flags	no flags	no flags	no flags	no flags	no flags	no flags	no flags
NH_3 (lb/h)	5.49	0.120	0.723	0.450	0.639	0.270	5.50
NH_3 (mg/b)	795	69.1	161	47.3	133	27.5	807
Cr flags	no flags	no flags	BDL	no flags	DLL	no flags	NR
Cr (lb/h)	1.09E-03	4.07E-04		2.44E-03	1.11E-03	7.30E-04	
Cr (μg/b)	158	234		257	231	74.3	
Pb flags	DLL	no flags	no flags	no flags	DLL	BDL	NR
Pb (lb/h)	4.64E-04	1.50E-04	1.15E-03	3.11E-03	6.27E-04		
Pb (μg/b)	67.2	86.4	255	327	130		
Mn flags	no flags	no flags	no flags	no flags	no flags	no flags	NR
Mn (lb/h)	7.54E-04	9.88E-04	2.40E-03	9.46E-04	7.70E-04	3.84E-03	
Mn (μg/b)	109	569	533	99.5	160	391	
Ni flags	DLL	no flags	no flags	no flags	no flags	no flags	NR
Ni (lb/h)	6.08E-04	1.63E-02	4.61E-03	3.33E-03	2.18E-03	1.14E-02	
Ni (μg/b)	88.1	9,390	1,020	350	453	1,160	
oHg flags	BDL	DLL	DLL	no flags	DLL	BDL	NR
oHg (lb/h)		1.50E-05	7.24E-05	6.78E-05	1.54E-06		
oHg (μg/b)		8.64	16.1	7.13	0.320		
eHg flags	BDL	DLL	no flags	BDL	DLL	no flags	DLL
eHg (lb/h)		3.00E-05	1.04E-04		3.86E-05	2.42E-05	2.73E-05
eHg (μg/b)		17.3	23.1		8.02	2.46	4.00
HCN flags	no flags	no flags	no flags	no flags	no flags	BDL	no flags
HCN (lb/h)	12.0	5.36	2.07	0.460	32.2		3.33
HCN (mg/b)	1,740	3,090	460	48.4	6,690		488

KEY Feed HTU: CU feed hydrotreating in percent or Mb/d. ESP: electrostatic precipitator. WS: wet scrubber Inj.: ammonia injection. Coke burn rate in short tons/calender day. PM: total particulate matter. cPM: condensable particulate matter. NH_3: ammonia. Cr: chromium. Pb: lead. Mn: manganese. Ni: nickel. oHg: oxidized/organic mercury. eHg: elemental mercury. HCN: hydrogen cyanide. DLL: detection level limited; analyte was below method detection level in one or more test runs. BDL: analyte was below MDL in all test runs; data not used quantitatively.

Table S14 (continued). Emission data for toxic pollutants detected in source tests of multiple CCUs, with calculations for median and 90th Percentile emissions/barrel—page 2 of 2.

Site	Sunoco Philadelphia PA[a]	Valero Port Arthur TX[a]	Hovensa St. Croix VI[a]	Chevron Richmond CA[b]	Number of the 11 CCUs where analyte was positively detected	Median emissions per barrel for CCUs where analyte was detected	90th Percentile emissions per barrel for CCUs where analyte was detected
Feed HTU	0%[d]	95%[d]	0.4%[d]	80%[e]			
PM control	venturi/WS[d]	venturi/WS[d]	venturi/WS[d]	ESP & Inj.[e]			
Coke (t/d)	879[a]	570[a]	782[a]	812[b]			
Capacity	90.0 Mb/d[g]	73.5 Mb/d[d]	160 Mb/d[d]	80.0 Mb/d[e]			
Test rate	79.29 Mb/d[a]	52.21 Mb/d[a]	113.1 Mb/d[a]	76.02 Mb/d[b]			
PM flags	no flags	no flags	no flags	DLL			
PM (lb/h)	116	8.51	38.2	78.0			
PM (g/b)	16.0	1.77	3.68	11.2	10	3.60	11.7
cPM flags	no flags	no flags	no flags	no flags			
cPM (lb/h)	34.2	2.29	22.8	73.4			
cPM (g/b)	4.70	0.477	2.19	10.5	10	2.04	5.28
PM lb/t coke	3.17	0.358	1.17	2.31			
cPM/PM (%)	29%	27%	60%	94%			
NH_3 flags	BDL	no flags	no flags	no flags			
NH_3 (lb/h)		0.522	9.85	12.8			
NH_3 (mg/b)		109	948	1,830	10	147	1,040
Cr flags	NR	no flags	no flags	NR			
Cr (lb/h)		4.21E-04	1.40E-03				
Cr (μg/b)		87.8	135		7	158	243
Pb flags	NR	no flags	no flags	NR			
Pb (lb/h)		2.16E-04	1.90E+03				
Pb (μg/b)		45.0	183		7	130	284
Mn flags	NR	no flags	no flags	NR			
Mn (lb/h)		6.71E-04	6.30E-03				
Mn (μg/b)		140	606		8	275	580
Ni flags	NR	no flags	no flags	NR			
Ni (lb/h)		1.11E-03	5.30E-03				
Ni (μg/b)		231	510		8	481	3,630
oHg flags	NR	no flags	no flags	NR			
oHg (lb/h)		1.90E-05	2.92E-05				
oHg (μg/b)		3.96	2.81		6	5.55	12.4
eHg flags	no flags	BDL	no flags	NR			
eHg (lb/h)	7.09E-04		2.55E-04				
eHg (μg/b)	97.3		24.5		7	17.3	53.7
HCN flags	BDL	no flags	no flags	NR			
HCN (lb/h)		42.0	105				
HCN (mg/b)		6,540	10,100		8	2,410	7,710

KEY Feed HTU: CU feed hydrotreating in percent or Mb/d. ESP: electrostatic precipitator. WS: wet scrubber Inj.: ammonia injection. Coke burn rate in short tons/calender day. PM: total particulate matter. cPM: condensable particulate matter. NH_3: ammonia. Cr: chromium. Pb: lead. Mn: manganese. Ni: nickel. oHg: oxidized/organic mercury. eHg: elemental mercury. HCN: hydrogen cyanide. DLL: detection level limited; analyte was below method detection level in one or more test runs. BDL: analyte was below MDL in all test runs; data not used quantitatively.

Table S14 notes: (a) Data from EPA ICR source tests; for emission data *see* esp. Goehl (2012) *Summary of fluid catalytic cracking unit emission source test reports* (*RS11*). (b) Data from Bay Area Air Quality Management District (BAAQMD) source tests (*RS23, RS24*). These source tests were performed before EPA revised cPM sampling protocol in 2011 and used a version of the previous protocol; BAAQMD has said it will not enforce cleanup based on these results, however, it has continued to rely upon them in its emissions inventory, and the company has provided source data supporting them as well (*RS25, RS26*). (c). Data from *Oil & Gas Journal* (*RS21*). (d). Data from EPA public data reports for ICR 'Component 1' (*RS11*). (e). Data from Title V air permit issued by BAAQMD to the Chevron Richmond Refinery; BAAQMD: San Francisco, CA (www.baaqmd.gov). (f). Data from US EIA *Refinery Capacity Data by Individual Refinery* for year-2011 (*RS9*). (g). Estimated by the author based on EPA ICR non-CBI data, per. comm. with E. Goehl (Dec. 2014; *RS11*). (h). Test rate estimated at 90% of unit capacity based on EPA ICR source test guidance to test at a minimum of 90% capacity.

Overall, these emissions data do not appear to follow a 'normal' or 'Gaussian' distribution, suggesting that median values may better represent the central tendency of the data.

Note that low cPM/PM ratios tend to occur with high nickel emissions/barrel (Kapolei and Robinson plants), while high cPM/PM ratios occur with high ammonia emissions (Torrance and Richmond plants). Nickel is a typical component of CCU catalyst, and catalyst fines are a source of coarser PM in CCU emissions. Excessive ammonia injection has been linked to high cPM emissions (*RS27, RS28*), and the three highest-NH_3-emitting CCUs measured for cPM (Torrance; St. Croix; Richmond) each emits cPM in excess of the 2.04 grams/barrel median value for this data set. The ten CCUs reporting cPM in the table are a small fraction of all US CCUs, and NH_3 injection is a common practice. If this this practice is underrepresented in the Table S14 data set, the median value for these data may underestimate cPM emissions from US CCUs industry-wide. These observations support carrying forward both the median and the 90th Percentile values (*see* Table S14 final columns) in estimates of potential CCU emissions of cPM.

Note also that the 'baseline' emissions/b in Table S14 would need to be adjusted as shown in Table S6 (+0.69x) to account for the greater density and CCU coke mass yields of CCU feeds in the +20–50% dilbit scenarios.

Table S15. Comparison of DCU and CCU emissions estimated in this work and US refinery Toxic Chemical Release Inventory emissions.

	US refinery emissions from the Toxics Release Inventory (TRI)[a]	Lower bound process[b,c] baseline from this analysis		Upper bound process[b,c] baseline from this analysis	
		Emissions	(% of TRI)	Emissions	(% of TRI)
Benzene (tonnes/y)[b]	514	310	60%	644	125%
Metals (kg/y)[c]					
Chromium	1,064	277	26%	427	40%
Lead	1,941	228	12%	499	26%
Manganese	1,481	483	33%	1,018	69%
Nickel	8,456	845	10%	6,374	75%
Mercury	549	40	7%	116	21%
Hydrogen cyanide[c]					
HCN (tonnes/y)	1,965	4,232	215%	13,539	689%

Table S15 notes:

(a) Stack and fugitive emissions from all US refinery sources as reported by US EPA in the Toxic Chemical Release Inventory; retrieved from www.epa.gov Dec. 2014. Benzene data are the average from 2011–2013. Metals data include all records from 2013 containing the name of the metal (e.g., 'chromium and chromium compounds'). Hydrogen cyanide data are from 2013. Note that TRI emission estimates are generally semi-quantitative at best, and their accuracy and precision should not be assumed or overestimated.

(b) DCU emissions of benzene, calculated based on a 2.18 MMb/d DCU feed rate[9] are compared with total refinery emissions of benzene from the TRI. Lower bound DCU emissions are based on the low end of the range for vents and coke cutting emissions in Table S12; upper bound DCU emissions are based on the low end of the range for vents, cutting and process water handling emissions in Table S12. The upper bound estimate of current DCU emissions based on these data exceeds the refinery wide TRI estimate. This is consistent with the underestimation based on vent emissions alone that is documented in Table S12, especially when one recalls that EPA has published no protocol for estimating DCU emissions of volatile chemicals from the other decoking operations of DCUs (*RS18*). Moreover, protocols for estimating fugitive emissions from other refinery sources (such as hydrocarbon storage tanks) have been shown to result in emission estimates roughly an order of magnitude lower than those found by direct measurements (*RS20*). It is thus reasonable to suspect that the TRI data might underestimate

[9] Table S4 data are scaled to DCU percent of coking capacity (2.303 • 2.542/2.687 = 2.179; rounded to 2.18).

refinery benzene emissions, and even if that were not the case, the lower bound estimate (60% of TRI benzene emissions) would not appear unreasonable for a strong benzene source within refineries, such as DCUs.

(c) CCU emissions of metals and HCN, calculated based on the 2013 CCU feed rate (4.811 MMb/d; Table S4) are compared with total refinery emissions of benzene from the TRI. Lower bound CCU emissions/barrel are based on the median emission values calculated in Table S14; upper bound CCU emissions are based on the 90th Percentile emission/b values in Table S14. The estimates of current CCU metals emissions ranges from 7–33% of refinery wide TRI estimates at the lower bound and from 21–75% of those TRI estimates at the upper bound. These results are generally consistent with a strong metal emissions source within refineries. CCU emissions have been shown to have high metals concentrations relative to other refinery sources (*RS22*), and CCU vents are relatively high-volume refinery process sources (*RS18*).

Hydrogen cyanide (HCN) emissions estimated from the data in Table S14 at 2013 CCU feed rates exceed the 2013 TRI refinery emissions estimate for HCN by 115% at the lower bound of the estimate and by 589% at its upper bound. The reason for this discrepancy is not known: it may be that the TRI underestimates HCN emissions, or that the eight CCUs represented for HCN emissions in the Table S14 source tests overestimate sector wide HCN emissions, or both. Note that the three CCUs in Table S14 reporting results that drive the upper-bound HCN emission estimates are not the same units that drive the upper-bound cPM emission estimates.

Table S16. Comparison of potential emission increments with CEQA thresholds.

Scenario	20/80 dilbit/baseline blend	50/50 dilbit/baseline blend
Notional CCU at a refinery		
Assumed baseline feed rate (Mb/d)	80.0	80.0
Feedstock-related rate increase (%)	8.09%	14.8%
Feedstock-related rate increase (Mb/d)	6.47	11.82
cPM lower bound (g/b)	3.45	3.45
cPM upper bound (g/b)	8.92	8.92
cPM lower bound (kg/day)	22.3	40.7
cPM upper bound (kg/day)	57.8	105
cPM lower bound in short tons (t/yr)	**9**	**16**
cPM upper bound in short tons (t/yr)	**23**	**42**
Air quality significance threshold (t/yr)	**10**	**10**
Notional DCU at a refinery		
Assumed baseline feed rate (Mb/d)	50.0	50.0
Feedstock-related rate increase (%)	14%	47%
Feedstock-related rate increase (Mb/d)	7.00	23.5
VOC lower bound (g/b)	63	63
VOC upper bound (g/b)	130	130
VOC lower bound (kg/day)	441	1,480
VOC upper bound (kg/day)	910	3,050
VOC lower bound in short tons (t/yr)	**177**	**595**
VOC upper bound in short tons (t/yr)	**366**	**1,230**
Air quality significance threshold (t/yr)	**10**	**10**

Table S16 notes: Results from tables S6,[10] S12 and S14 are applied to a notional refinery with a baseline CCU throughput of 80 Mb/d and a baseline DCU throughput of 50 Mb/d. 'Notional' means that this refinery does not necessarily exist, although units run at or near these rates, and the example is therefore reasonable for purposes of illustration. The purpose of this example is to illustrate the potential significance of CCU and DCU emissions in the +20–50% dilbits scenarios at the facility (community) level. The 'air quality thresholds' shown are for fine particulate and VOC emissions and are those recommended by the Bay Area Air Quality Management District (BAAQMD) for determining the significance of potential emissions from operating proposed projects pursuant to the California Environmental Quality Act (CEQA).

[10] Baseline CCU emissions/b were adjusted (+0.69x) for coke-burn mass increments as shown in Table S6 notes.

Table S17. Association of coke yield with crude feed quality details (Table 2 from CBE, 2011).

Table 2. Refinery coke yield observed and California coke yield predicted by crude quality (R^2 0.97).

U.S. data:		*y* observed	*x* (explanatory variable) data observed			coke yield predicted (95% confidence)		
		total coke	crude den-	crude sul-	capacity util-	lower bound	prediction	upper bound
PADD	year	(% yield)	sity (kg/m^3)	fur (kg/m^3)	ization (%)	(% yield)	(% yield)	(% yield)
1	1999	3.1	858.20	8.24	90.9	2.6	3.0	3.4
1	2000	3.0	860.18	8.00	91.7	2.7	3.1	3.4
1	2001	3.3	866.34	7.71	87.2	3.0	3.4	3.8
1	2002	3.1	865.71	7.45	88.9	2.9	3.3	3.7
1	2003	2.9	863.44	7.43	92.7	2.7	3.1	3.5
1	2004	3.1	865.44	7.79	90.4	3.0	3.3	3.7
1	2005	2.9	863.38	7.17	93.1	2.6	3.0	3.4
1	2006	3.0	864.12	7.17	86.7	2.7	3.1	3.5
1	2007	3.2	864.33	7.26	85.6	2.8	3.2	3.5
1	2008	3.3	863.65	7.08	80.8	2.7	3.1	3.5
2	1999	4.2	858.25	10.64	93.3	3.3	3.7	4.0
2	2000	4.3	860.03	11.35	94.2	3.6	4.0	4.4
2	2001	4.3	861.33	11.37	93.9	3.7	4.1	4.5
2	2002	4.1	861.02	11.28	90.0	3.7	4.0	4.4
2	2003	4.2	862.80	11.65	91.6	3.9	4.3	4.6
2	2004	4.3	865.65	11.86	93.6	4.1	4.5	4.9
2	2005	4.5	865.65	11.95	92.9	4.1	4.5	4.9
2	2006	4.4	865.44	11.60	92.4	4.0	4.4	4.8
2	2007	4.3	864.07	11.84	90.1	4.0	4.4	4.8
2	2008	4.3	862.59	11.73	88.4	3.9	4.3	4.7
3	1999	4.8	869.00	12.86	94.7	4.6	5.0	5.4
3	2000	4.8	870.29	12.97	93.9	4.7	5.1	5.5
3	2001	5.3	874.43	14.34	94.8	5.4	5.8	6.1
3	2002	5.7	876.70	14.47	91.5	5.6	6.0	6.4
3	2003	5.7	874.48	14.43	93.6	5.4	5.8	6.2
3	2004	5.9	877.79	14.40	94.1	5.6	6.0	6.4
3	2005	6.0	878.01	14.40	88.3	5.7	6.1	6.4
3	2006	6.2	875.67	14.36	88.7	5.5	5.9	6.3
3	2007	6.0	876.98	14.47	88.7	5.6	6.0	6.4
3	2008	6.0	878.66	14.94	83.6	5.9	6.3	6.7
5	1999	6.1	894.61	11.09	87.1	5.8	6.2	6.6
5	2000	6.3	895.85	10.84	87.5	5.8	6.2	6.6
5	2001	6.0	893.76	10.99	89.1	5.7	6.1	6.5
5	2002	6.0	889.99	10.86	90.0	5.4	5.8	6.2
5	2003	6.2	889.10	10.94	91.3	5.4	5.8	6.2
5	2004	6.1	888.87	11.20	90.4	5.5	5.9	6.2
5	2005	6.2	888.99	11.38	91.7	5.5	5.9	6.3
5	2006	6.0	887.65	10.92	90.5	5.3	5.7	6.1
5	2007	5.8	885.54	11.07	87.6	5.2	5.6	6.0
5	2008	6.1	890.16	12.11	88.1	5.8	6.2	6.6
California data:			data inputs for California predictions					
Cal. avg. 2004		7.4	899.23	11.46	93.0	6.2	6.6	7.0
Cal. avg. 2005		7.7	900.56	11.82	95.0	6.4	6.8	7.2
Cal. avg. 2006		7.4	899.56	11.73	91.5	6.3	6.7	7.1
Cal. avg. 2007		7.1	899.84	11.89	88.3	6.4	6.8	7.2
Cal. avg. 2008		7.4	902.00	12.85	91.0	6.8	7.2	7.6
Cal. avg. 2009		7.6	901.38	11.70	82.9	6.5	6.9	7.2
70/30 HO/CA blend			948.39	22.59	90.8	12.4	13.0	13.5
70/30 NB/CA blend			1001.73	34.98	90.8	19.1	20.0	20.8

Prediction for replacement by heavy oil (HO) and natural bitumen (NB) at avg. 1999–2008 U.S. capacity utilization. 70/30 HO/CA crude feed: 70/30 blend of heavy oil/Calif.-produced crude. 70/30 NB/CA crude feed: 70/30 blend of natural bitumen/Calif.-produced crude. California-produced crude quality is the 2004–2008 average *(Ref. 7 at Table 2-3)*. Avg. heavy oil and natural bitumen qualities are from USGS *(5, 9)*. All other data from *Ref. 7 at Table 2-1*. Total (market & catalyst) coke yield predicted by crude density and sulfur content and refinery capacity utilization; analysis by partial least squares regression on the U.S. (PADDs) data shown.

Table S17 notes: Data from *RS13* and *RS29,* excerpted from comments regarding California's Low Carbon Fuel Standard submitted to the California Air Resources Board in 2011 by Communities for a Better Environment (*RS30*). Both CCU 'catalyst' coke and DCU 'marketable' coke are shown. The table illustrates that a substantial increase in coke production is reasonably predictable from a switch to denser, more contaminated crude feeds, such as bitumen-derived dilbits. DCU 'marketable' coke production, which often is exported by US refineries (Table S8), is typically used as fuel in cement, metals, and electric power production and a fraction of this coke is calcined for manufacturing of carbon products such as graphite and charcoal briquettes. Each of these uses of pet coke is high-emitting, and at least some of them (e.g., power generation; outdoor grilling) place this high-emitting refinery byproduct in competition with less emitting alternatives. However, petroleum fuel cycle analyses do not always account for the emissions 'exported' by refiners with DCU-produced coke—or the potential that these emissions could grow if lower quality refinery feedstock is processed.

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Attachment 19

DEBORAH GORDON

ADAM BRANDT

JOULE BERGERSON

JONATHAN KOOMEY

KNOW YOUR OIL

CREATING A GLOBAL OIL-CLIMATE INDEX

DEBORAH GORDON

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ACRONYMS

AGO — Atmospheric Gas Oil

ANS — Alaska North Slope

API — measure (in degrees) of an oil's gravity or weight

AR — Atmospheric Residue

bbl — Barrel

C-B — Coke Burned

CNR — Catalytic Naphtha Reformer

CO_2 — Carbon Dioxide

CO_2 eq. — Carbon Dioxide Equivalent (including all GHGs)

dilbit — Diluted Bitumen

FCC — Fluid Catalytic Cracking

GHGs — Greenhouse Gases

GIS — Geographic Information System

GO — Gas Oil

GO-HC — Gas Oil-Hydrocracker

GOR — Gas-to-Oil Ratio

HC — Hydrocracker

HVGO — Heavy Vacuum Gas Oil

kg — Kilogram

km — Kilometer

LCA — Life-Cycle Assessment

LSR — Light Straight Run

LTO — Light Tight Oil

LVGO — Light Vacuum Gas Oil

mbd — Million barrels per day, also termed “mbpd”

MJ — Megajoule (unit of energy)

OCI — Oil-Climate Index

OPEC — Organization of the Petroleum Exporting Countries

OPEM — Oil Products Emissions Module

OPGEE — Oil Production Greenhouse Gas Emissions Estimator

PRELIM — Petroleum Refinery Life-cycle Inventory Model

RFG — Refinery Fuel Gas

SCO — Synthetic Crude Oil

SMR — Steam Methane Reformer

SOR — Steam-to-Oil Ratio

tonne — Metric Ton

VR — Vacuum Residue

ACKNOWLEDGMENTS

THIS WORK WOULD not have been possible without support from the blue moon fund, Oak Foundation, William and Flora Hewlett Foundation, ClimateWorks Foundation, and the Rockefeller Family Fund. Support from the Energy Foundation was also timely and helpful. We thank all of these organizations for their generosity. In particular, Dr. Ji-Qiang Zhang, Kristin Tracz, Tyler Gibson, Leslie Harroun, Margarita Parra, Joe Ryan, Anthony Eggert, Charles McElwee, Patty Monahan, Heidi Binko, and Larry Shapiro have provided important insights and encouragement throughout the development of the Oil-Climate Index project.

So many colleagues at the Carnegie Endowment were engaged and helped this project flourish. Thank you to Jessica Tuchman Mathews for her ongoing encouragement and to Ambassador William J. Burns, the new president of the Carnegie Endowment, who arrived just as the first phase of the index was concluding. Eugene Tan (Carnegie junior fellow, 2014–2015) worked tirelessly and provided tremendous project support. To the entire Carnegie communications team, you are amazing. We are indebted to Tom Carver, Tim Martin, Rebecca White, Samuel Brase, Jocelyn Soly, Ilonka Oszvald, Courtney Griffith, Jessica Katz, Lauren Dueck, Nick Parrott, and everyone else on the sixth floor. Oil data was a constant quest throughout the development of the Oil-Climate Index, and the Carnegie Endowment Library staff, Kathleen Higgs, Christopher Lao-Scott, and Keigh Hammond, were incredibly helpful in digging up assays. Julia Judson-Rea, David Livingston, Anisha Mehta, and David Burwell were there from the start and their support was incredibly valuable.

Numerous Stanford University colleagues contributed significantly to the project, including Kourosh Vafi, Sharad Bharadwaj, Yuchi Sun, Jacob Englander, and Zachary Schmidt (Analytics Press). Thank you to our University of Calgary colleagues who provided their continued research support, including Kavan Motazedi and former colleague Jessica Abella, as well as Heather MacLean from the University of Toronto.

We were very fortunate to have Development Seed onboard to create the OCI web tool. The entire team was phenomenal. Thank you to those experts who attended the Carnegie Endowment OCI Workshop in September 2014 and provided excellent feedback on our project, including Andrew Nicholls (Pacific Northwest National Laboratory), Anthony Andrews (Congressional Research Service), Bill Morrow (Lawrence Berkeley National Laboratory), Chris Malins (International Council on Clean Transportation), Erin Flanagan (Pembina Institute), Fabrice Vareille (U.S. Geological Survey), Greg Cooney (Booz Allen Hamilton and National Energy Technology Laboratory), Hassan El-Houjeiri (Shell), Ian Laurenzi (ExxonMobil), Jeremy Martin (Union of Concerned Scientists), Jim Duffy (California Air Resources Board), Michael Wang (Argonne National Laboratory), Nusa Urbancic (Transport & Environment), Quindi Franco (U.S. Government Accountability Office), Matthew McManus (U.S. Department of State, Energy & Natural Resources Bureau), Dean Bears, Trevor Demayo, and Susann Nordrum (Chevron), and Carmen Difiglio and Peter Whitman (U.S. Department of Energy).

Naturally, this report's contents remain entirely the responsibility of its authors.

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SUMMARY

OIL IS CHANGING. Conventional oil resources are dwindling as tight oil, oil sands, heavy oils, and others emerge. Technological advances mean that these unconventional hydrocarbon deposits in once-unreachable areas are now viable resources. Meanwhile, scientific evidence is mounting that climate change is occurring, but the climate impacts of these new oils are not well understood. The Carnegie Endowment's Energy and Climate Program, Stanford University, and the University of Calgary have developed a first-of-its-kind Oil-Climate Index (OCI) to compare these resources.

ALL OILS ARE NOT CREATED EQUAL

- Thirty global test oils were modeled during Phase 1 of the index.
- Greenhouse gas (GHG) emissions were analyzed throughout the entire oil supply chain—oil extraction, crude transport, refining, marketing, and product combustion and end use.
- There is an over 80 percent difference in total GHG emissions per barrel of the lowest GHG-emitting Phase 1 oil and the highest.

- Climate impacts vary whether crudes are measured based on their volumes, their products' monetary values, or their products' energy delivered.
- The GHG emission spread between oils is expected to grow as new, unconventional oils are identified.
- Each barrel of oil produces a variety of marketable products. Some are used to fuel cars and trucks, while others—such as petcoke and fuel oils—flow to different sectors. Developing policies that account for leakage of GHG emissions into all sectors is critical.
- The variations in oils' climate impacts are not sufficiently factored into policymaking or priced into the market value of crudes or their petroleum products.
- As competition among new oils for market share mounts, it will be increasingly important to consider climate risks in prioritizing their development.

NEXT STEPS FOR THE OCI

- In order to guide energy and climate decisionmaking, investors need to make realistic asset valuations and industry must make sound infrastructure plans. Policymakers need to condition permits, set standards, and price carbon. And the public needs information and incentives to make wise energy choices.
- The OCI can shape how these stakeholders address the climate impacts of oil, and the use of the index can foster critical public-private discussions about these issues.
- The most GHG-intensive oils currently identified—gassy oils, heavy oils, watery and depleted oils, and extreme oils—merit special attention from investors, oil-field operators, and policymakers.
- To increase transparency on a greater volume and variety of global oil resources, it will be necessary to expand the OCI. This will require more high-quality, consistent, open-source oil data. This information will facilitate the restructuring of oil development in line with climate realities.

INTRODUCTION

THE CHARACTER OF oil is changing. Consumers may not notice the transformation—prices have fluctuated, but little else appears to have changed at the gas pump. Behind the scenes, though, the definition of oil is shifting in substantial ways. There is oil trapped tightly in shale rock, and oil pooled many miles below the oceans. Oil can be found in boreal forests, Arctic permafrost, and isolated geologic formations. Some oils are as thick as molasses or as gummy as tar, while others are solid or contain vastly more water or gas than normal.

As oil is changing, so, too, is the global climate.

Oil resources were once fairly homogeneous, produced using conventional means and refined into a limited number of end products by relatively simple methods. This is no longer the case. Advancements in technology mean that a wider array of hydrocarbon deposits in once-unreachable areas are now viable, extractable resources. And the techniques to turn these unconventional oils into petroleum products are becoming increasingly complex.

As oil is changing, so, too, is the global climate. The year 2014 ranked as the earth's warmest since 1880. Fossil fuels—oil along with coal and methane gas—are the major culprits.

The only way to determine the climate impacts of these previously untapped resources—and to compare how they stack up against one another—is to assess their greenhouse gas (GHG) emissions at each stage in the oil supply chain: exploration, extraction, processing, refining, transport, and end use. The more energy it takes to carry out these processes, the greater the impact on the climate. And in the extreme case of some of these oils, it may take nearly as much energy to produce, refine, and transport them as they provide to consumers. Moreover, each oil yields a different slate of petroleum products with different combustion characteristics and climate footprints.

The Oil-Climate Index (OCI) is a metric that takes into account the total life-cycle GHG emissions of individual oils—from upstream extraction to midstream refining to downstream end use. It offers a powerful, yet user-friendly, tool that allows investors, policymakers, industry, the public, and other stakeholders to compare crudes and assess their climate consequences both before development decisions are made as well as once operations are in progress. The Oil-Climate Index will also inform oil and climate policy making.

The index highlights two central facts: The fate of the entire oil barrel is critical to understanding and designing policies that reduce a crude oil's climate impacts. And oils' different climate impacts are not currently identified or priced into the market value of competing crudes or their petroleum products. As such, different oils may in fact entail very different carbon risks for resource owners or developers.

Different oils may entail very different carbon risks for resource owners or developers.

Analysis of the first 30 test oils to be modeled with the index reveals that emission differences between oils are far greater than currently acknowledged. Wide emission ranges exist whether values are calculated per barrel of crude, per megajoule of products, or per dollar value of products, and it is expected that these emission ranges could grow as new, unconventional oils are identified.

There are several critical variables that lead to these variations in oils' life-cycle climate emissions. They include how gas trapped with the oil is handled by producers, whether significant steam is required for oil production, if a lot of water is present as the oil reservoir depletes, how heavy (viscous) or deep the oil is, what type of refinery is used, and whether bottom-of-the-barrel products like petroleum coke (known as petcoke) are combusted. Given these factors, the most climate-intensive oils currently identified—gassy oils, heavy oils, watery and depleted oils, and extreme oils—require special attention from investors, operators, and policymakers.

Expanding the index to include more global oils is necessary in order to compare greater volumes of crudes. This requires more transparent, high-quality, consistent, accessible, open-source data. As competition mounts between new oils, information about emerging resources is needed to increase market efficiency, expand choices, leverage opportunities, and address climate challenges.

OIL 2.0

CONCERNS ABOUT OIL scarcity beset the world for nearly half a century, but that may no longer be the overriding worry. Larger questions loom about the changing nature of oil resources, their unknown characteristics, their climate and other environmental impacts, and policies to safely guide their development and use.

Indeed, there are thousands of oils available globally for production and use. The earth is stocked with a surfeit of hydrocarbons. As of 2013, there are an estimated 24 trillion barrels of oil in place, of which 6 trillion barrels are deemed technologically recoverable.

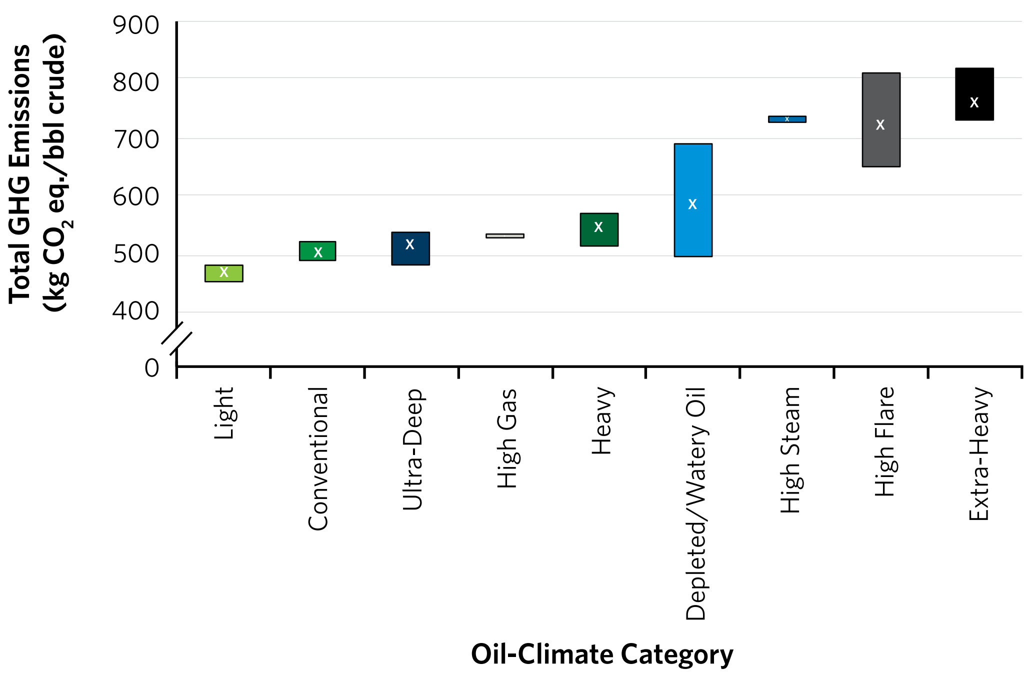
Advancements in technology that have unlocked unconventional hydrocarbon deposits in once-unreachable areas are costly and risky in both private and social terms.

These resources take different forms—from rocky kerogen to sludgy tar to volatile gassy liquids. They exist under vastly different conditions: deep and shallow; onshore and offshore; pooled and dispersed; and in deserts, permafrost, rainforests, and grasslands. An evolving array of techniques must be employed to transform them into a myriad of petroleum products, some more valuable than others, which flow in all directions to every economic sector and most household products.

Advancements in technology that have unlocked unconventional hydrocarbon deposits in once-unreachable areas are costly and risky in both private and social terms. Many of these advancements result in larger GHG emissions than traditional extraction methods, and some oils have more than 80 percent higher emissions per barrel than others (see figure 1).

FIGURE 1

GHG Emission Ranges for 30 Phase 1 OCI Test Oils, by Category



Source: Authors' calculations (calculations will be made available online at CarnegieEndowment.org)

Notes: "X" represents average GHG emissions for OCI test oils in each oil category. Extra-heavy oils include oil sands.

Consider a few examples. For California's Midway Sunset oil field, a sizable portion of the oil's own energy content is used before any of the petroleum products the field ultimately provides reach consumers. This century-old oil field requires large volumes of steam to be injected into the reservoir to loosen the oil and allow it to flow. Generating this steam requires up to one-third of the energy content of the oil itself, in the form of natural gas. The water content of this oil is high and therefore takes extra energy to lift. Much of its oil is very heavy and requires energy-intensive, complex refining techniques. The combination of energy used in extraction and refining means almost half of Midway Sunset's total greenhouse gas emissions are released before the resource even gets to market.

Other oils, such as Norway Ekofisk, fare much better in these regards. This light oil is more easily produced. Extraction operations are tightly regulated by the Norwegian government; as such, the gas produced with the oil is gathered and sold instead of burned (or flared) on-site and wasted. Ekofisk oil is processed by the simplest hydroskimming refinery, and less than 10 percent of its greenhouse gases are emitted before it gets to market.

Oil markets, meanwhile, are durable given the lack of ready substitutes. Oil consumption has marched steadily upward, from 77 million barrels per day (mbd) in 2000 to 92 mbd in 2014, despite a major global economic downturn. Oil dominates the transportation sector, providing 93 percent of motorized transportation energy. Overall, the oil sector is responsible for a reported 35 percent of global GHG emissions.

All actors would be better served by accurate, transparent measures of climate risk associated with different oils.

Parsing oils by their climate impacts allows multiple stakeholders, each with their own objectives, to consider climate risks in prioritizing the development of future oils and the adoption of greater policy oversight of today's oils. While objectives of stakeholders may vary (for example, environmental nongovernmental organizations may have different perspectives than investors), all actors would be better served by accurate, transparent measures of climate risk associated with different oils.

THE MOST CHALLENGING OILS

EVEN WITH THE decline in oil prices that began in August 2014, there remains fierce competition between diverse global oils. A few of them are more challenging in terms of climate change than others.

- Gassy oils: Oil fields typically have some natural gas (or methane) and other lighter gases (ethane and others) associated with them. The more gas that is present, the more challenging and costly it is to safely manage these commodities. When the gas associated with certain gassy oils is not handled properly, usually due to lack of appropriate equipment, the gas is burned or released as a waste byproduct. Both flaring and venting operations are damaging to the climate as they release carbon dioxide, methane, and other GHG emissions. Oils that resort to these practices can result in at least 75 percent larger GHG footprints than comparable light oils that do not flare. Flaring policies vary. For example, it has been illegal to flare associated gas in Norway since the 1970s, making these oils some of the lowest emitting oils produced today.

- Heavy oils: The heavier the oil, the more heat, steam, and hydrogen required to extract, transport, and transform it into high-value petroleum products like gasoline and diesel. These high-carbon oils also yield higher shares of bottom-of-the-barrel products like petcoke that are often priced to sell. The heaviest oils have total GHG footprints that can be nearly twice as large as lighter oils.

- Watery and depleted oils: Depleted oil fields tend to produce significant quantities of water along with the oil. It takes a lot of energy to bring this water to the surface, process it, and reinject or dispose of it. If an oil field has a water-oil ratio of ten to one, that adds nearly 2 tons of water for every barrel of oil produced. Certain depleted oils in California's San Joaquin Valley, for example, produced 25 or 50 barrels of water per barrel of oil. Oils with high water-oil ratios can have total GHG footprints that are more than 60 percent higher than oils that are not so encumbered.

- Extreme oils: Some oils are difficult to access. For example, some oils are buried deeply below the surface, like the Chayvo oil field in Russia's Sakhalin shelf, which is reached by an incredible set of highly deviated wells that are about 7 miles long. How much energy it takes to recover such resources is highly uncertain. Still other oils are located in areas that sequester greenhouse gases like permafrost, boreal peat bogs, and rainforests. Removing these oils disrupts lands that store significant amounts of carbon, releasing substantial volumes of climate-forcing gases. GHG footprints may be significantly larger for oils that are difficult to access or located in climate-sensitive environments, and this merits further investigation.

There is far too little information about the new generation of oil resources.

Whether global oil production returns to record levels, wanes, or fluctuates in the future, there is little doubt that oils will be increasingly unconventional. And there is little doubt that oil extraction, refining, and consumption should be better understood. There is far too little information about the new generation of oil resources.

CREATING AN OIL-CLIMATE INDEX

AS THE CHANGING climate results in higher social costs, the environmental limitations on oil production and consumption will have more significant effects than the industry has heretofore acknowledged.[1] Recent research has shown that to keep the earth from warming more than 2 degrees Celsius from preindustrial times—the limit set in the 2009 Copenhagen Accord as the threshold for "dangerous" human interference in the climate system—at least one-third of the world's oil reserves should not be burned or the carbon from refined oil products' combustion should be safely stored.[2] Investors and companies facing such constraints will need data on the total life-cycle emissions from the exploration, extraction, transportation, refining, and combustion of oil resources, data that do not now exist, at least not in a consistent, transparent, and peer-reviewed way.

The Oil-Climate Index is designed to fill that void by analyzing total GHG emissions (including all co-products) for given crudes using three different functional units, or different metrics, for comparison. The first version of the index includes: emissions per barrel of crude produced, emissions per energy content of all final petroleum products, and emissions per dollar value of all petroleum products sold.

The Oil-Climate Index uses the following open-source tools to evaluate actual emissions associated with an individual oil's supply chain:

- **OPGEE** (Oil Production Greenhouse Gas Emissions Estimator), developed by Adam Brandt at Stanford University,[3] evaluates upstream oil emissions from extraction to transport to the refinery inlet.
- **PRELIM** (Petroleum Refinery Life-Cycle Inventory Model), developed by Joule Bergerson at the University of Calgary,[4] evaluates refining emissions and petroleum product yields.
- **OPEM** (Oil Products Emissions Module), developed by Deborah Gordon and Eugene Tan at the Carnegie Endowment for International Peace's Energy and Climate Program and Jonathan Koomey at Stanford University's Steyer-Taylor Center for Energy Policy and Finance, calculates the emissions that result from the transport and end use of all oil products yielded by a given crude. An overriding goal of the module is to include and thereby avoid carbon leakage from petroleum co-products.

While oil type, production specifications, and geography were initial factors in selecting oils to model in Phase 1 of the Oil-Climate Index, data availability turned out to be the overriding factor. The oils modeled in the first phase are found around the world (see table 1). Oils were analyzed across the entire value chain—the series of transformations and movements from an oil's origin to the consumption of the slate of petroleum products it yields.

TABLE 1
Locations of 30 Phase 1 OCI Test Oils

United States	Canada	Sub-Saharan Africa	Europe	Eurasia	Middle East & North Africa	Latin America & Caribbean	Asia-Pacific
U.S. California Midway Sunset	Canada Midale—Saskatchewan	Nigeria Obagi	UK Brent	Russia Chayvo	Iraq Zubair	Brazil Lula	China Bozhong
U.S. California South Belridge	Canada Syncrude Synthetic (SCO)—Alberta	Nigeria Bonny	UK Forties	Kazakhstan Tengiz	Kuwait Ratawi	Brazil Frade	Indonesia Duri
U.S. California Wilmington	Canada Suncor Synthetic A (SCO)—Alberta	Nigeria Agbami	Norway Ekofisk	Azerbaijan Azeri Light		Venezuela Hamaca	
U.S. Alaska North Slope	Canada Suncor Synthetic H (SCO)—Alberta	Angola Girassol					
U.S. Gulf Mars	Canada Cold Lake (Dilbit)—Alberta	Angola Kuito					
U.S. Gulf Thunder Horse	Canada Hibernia—Newfoundland						

Note: SCO is synthetic crude oil from upgraded oil sands; dilbit is diluted bitumen (a mixture of bitumen and diluent made from natural gas liquids, condensate, and other light hydrocarbons).

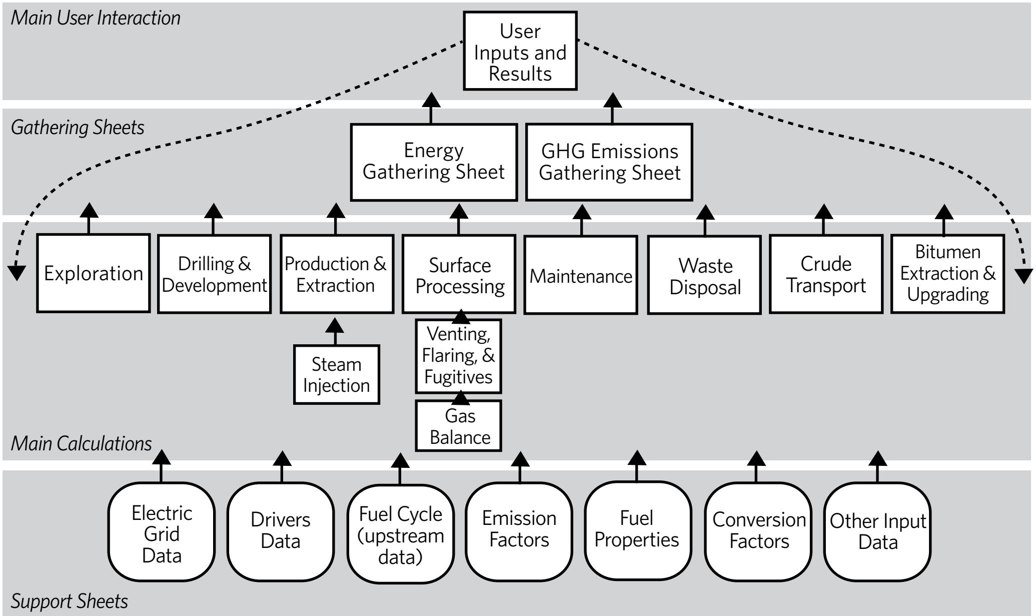
MODELING UPSTREAM OIL EMISSIONS

UNEARTHING OIL AND preparing it for transport to a refinery is the first step in the value chain. The processes involved differ from oil to oil. Together, exploration, production, surface processing, and transport of crude oil to the refinery inlet comprise upstream operations, and the resulting GHG emissions are modeled in OPGEE (see figure 2).

OPGEE PHASE 1 RESULTS

Crudes vary significantly in their upstream GHG impacts. To date, OPGEE has been run on approximately 300 global crudes, many of which are in California and Canada. This represents more upstream crude runs than any other modeling effort, including the National Energy Technology Laboratory's *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels* (twelve crudes in November 2008); the Jacobs Consultancy's *Life Cycle Assessment Comparison of North American and Imported Crudes* (thirteen crudes in 2009); TIAX Consulting's *Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions* (nine crudes in 2009); and IHS Consulting's *Comparing GHG Intensity of the Oil Sands and the Average U.S. Crude Oil* (28 crudes in 2014).

FIGURE 2
OPGEE Model Schematic



Source: Stanford University, Oil Production Greenhouse Gas Emissions Estimator

For the purposes of the Oil-Climate Index, it was critical that data were available to simultaneously model both upstream and midstream emissions. This narrowed the field down to 30 OCI test oils for the first phase.

There is large variation in upstream emissions across the 30 test oils. The oil with the highest emissions intensity has approximately twelve times the emissions of the lowest-intensity oil (see figure 3).

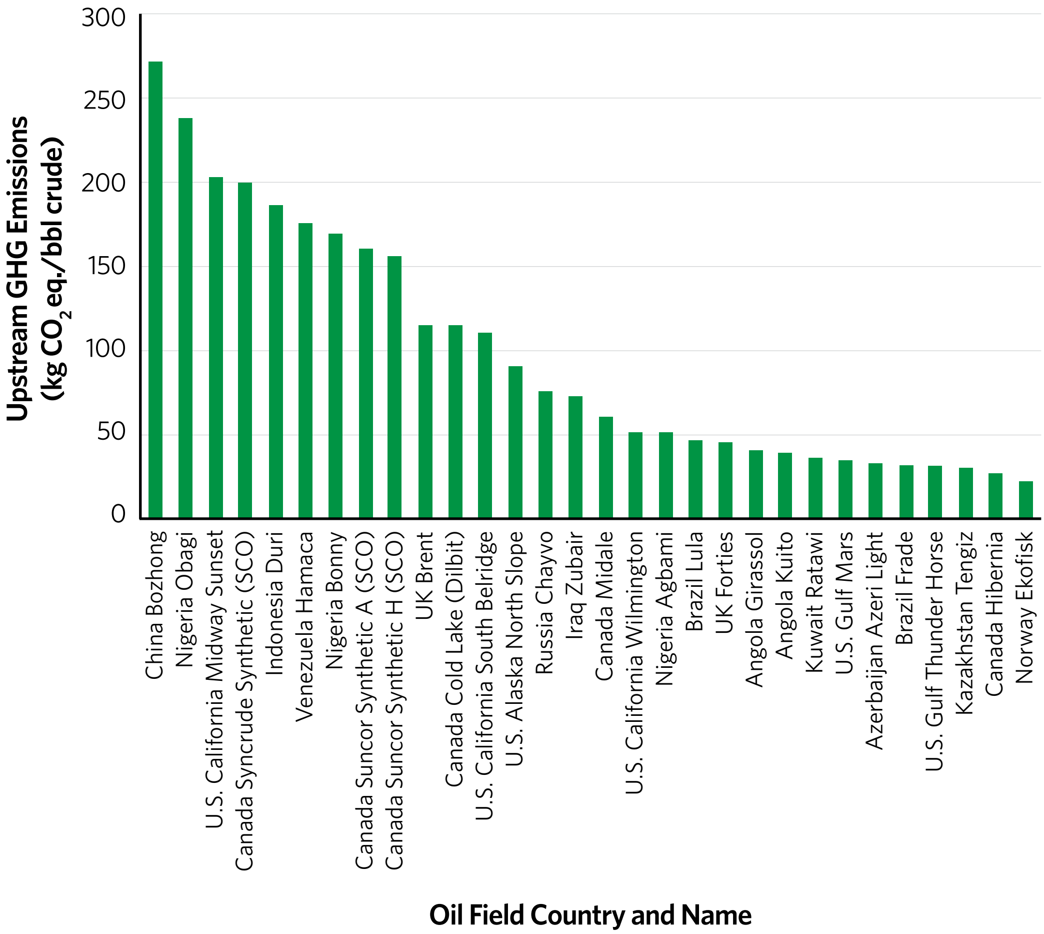
WHAT DRIVES UPSTREAM EMISSIONS?

The emissions from different oils have different origins. UK Brent, for example, emits most of its GHG emissions during surface processing, while California South Belridge emits more due to the steam used during production (see figure 4). Other upstream emissions drivers include the gas produced with the oil that may be flared or vented, depending on local conditions.

Oil location—including geography and ecosystem (such as desert, Arctic, jungle, forest, and offshore)—determines how disruptive extraction is to land use. When oil

FIGURE 3

OPGEE GHG Emission Results for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

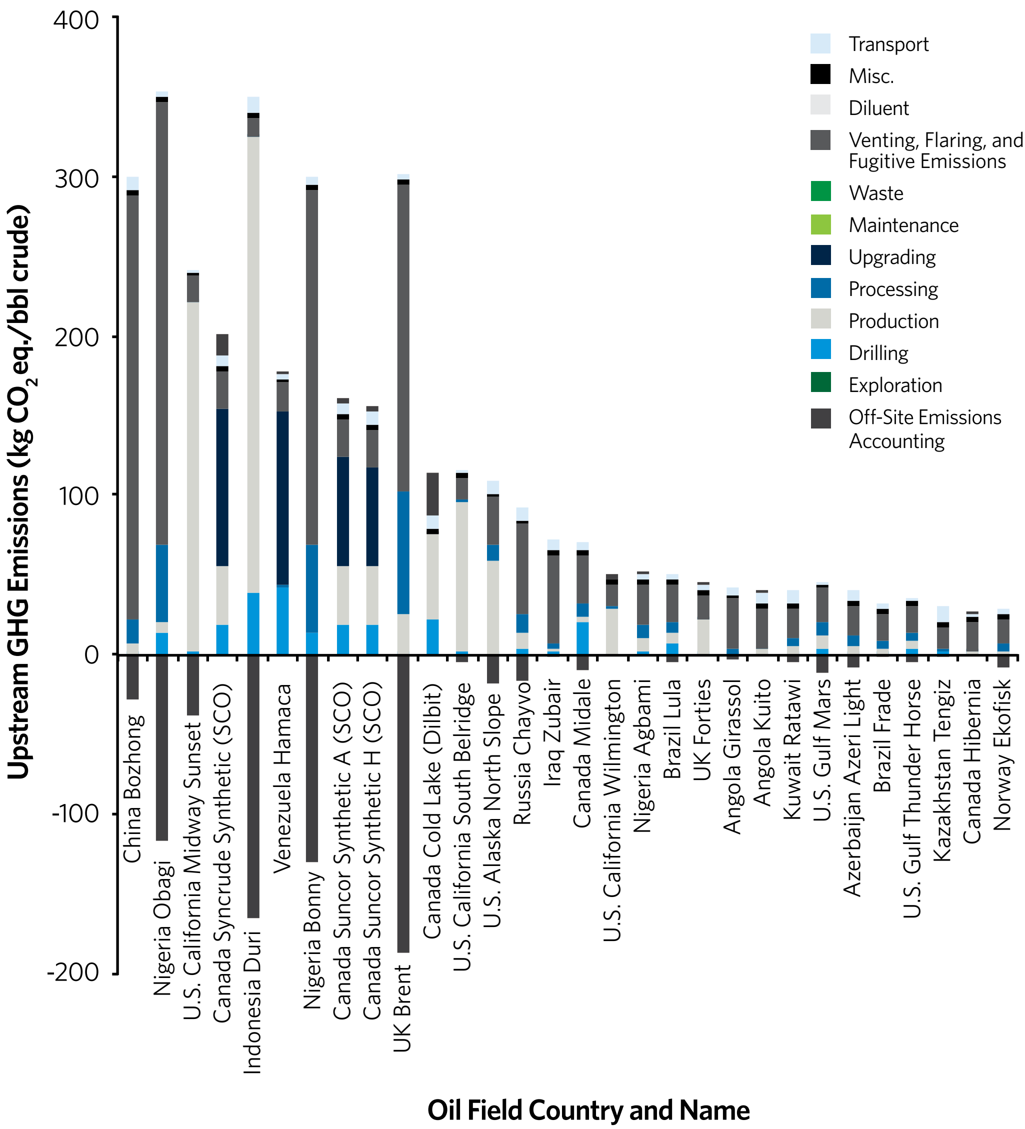
Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil. It is about 75 percent bitumen mixed with diluent to allow it to flow.

development activities change land use, this affects the land's biological (soil and plants) carbon storage capacity. The more naturally stored carbon that is released, the more greenhouse gases are emitted.

An oil field's location, its distance to transport hubs, and refinery selection determine the method that is used to move the resource and the resulting transport emissions. Pipelines, railroads, or trucks are used to ship the oil overland. Barges move oil over inland waterways, and seaborne crude shipments rely on marine tankers. In the first phase of the Oil-Climate Index, it was assumed as a default that all crude is sent to the city of Houston in Texas. As of January 2014, the U.S. states of Texas and Louisiana had more refining capacity than any nation, including China and Russia.[5]

FIGURE 4

Drivers of Upstream GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil. Off-site emissions accounting can be a credit (negative) or debit (positive).

OPGEE analysis points to a number of factors that result in particularly high upstream emissions:

- The methods used to recover extra-heavy (bitumen) and heavy oils often involve putting significant amounts of energy in to heat up resources so they can flow, consuming 10–30 percent of the energy content of the produced crude. These oils also typically have significant water-handling and treatment needs, and pumping water is energy-intensive.
- Ultra-light and light oils that have a high level of associated gas may be flared if gas-handling infrastructure is inadequate or missing. Disposing of this gas through flaring instead of gathering and selling it results in additional carbon dioxide emissions. This wasteful practice produces GHG emissions with no economic benefit.
- Hydraulically fractured oils can vent methane emissions due to gas flowback, which is when vapors return to the surface. This can happen when an oil well has been drilled and the piping and tubing infrastructure that has been put in place for ongoing production cannot adequately contain the gas associated with the oil.
- Conventional oil formations that are depleted and are running out of oil resources can produce significant quantities of water or require increased injection of substances to induce oil production.

OPGEE CHALLENGES

The largest source of uncertainty in OPGEE is the lack of information on global oil fields. Many operators and many regions of the world have few formal data publication requirements. Data quality is also an ongoing issue in modeling upstream emissions (see the appendix for details).

OPGEE utilizes about 50 data inputs, from simple entries like the name of the country where an oil field is located to challenging-to-obtain information such as an oil field's productivity index (expressed in daily production per unit pressure). Substantial research is involved in gathering OPGEE modeling data, which can be obtained from agencies, reports, scientific literature, and industry references.

OPGEE can function with limited data. The model has a comprehensive set of defaults and smart defaults that can fill in missing data. The more data found for a particular field, the more specific and less generic the emissions estimate becomes. All data are used to determine smarter default values over time.

As with all life-cycle assessment (LCA) models, boundaries must be drawn around the analysis. The handling of co-products that cross boundaries along the oil supply chain, from extraction to refining to end use, presents methodological challenges. For example, resulting GHG emissions from condensates of light liquids, like ethane, that can be stripped off and sold before oil is transported to a refinery are not expressly included in OPGEE. Emissions associated with exploration occur at the beginning of an oil field development project and are spread over the life of the field. Extraction emissions that occur routinely are estimated at a point in time and assumed to recur over the lifetime of the oil field.

OPGEE treats liquid petroleum as the principal product of upstream processes. Emissions associated with electricity generated on-site or natural gas produced that is gathered, sold, and not flared is credited back or deducted from total emissions in OPGEE accounting (see figure 4 above).[6] Any emissions from co-products like petcoke that are associated with upgrading heavy oils upstream of the refinery—as can be the case with Canadian bitumen and Venezuelan heavy oils—are not included in OPGEE unless the production process directly consumes petcoke (as in some oil-sands-based integrated mining and upgrading operations). Emissions from net production of petcoke have been included in the OPEM downstream combustion module.

Recent studies have found that uncertainty in OPGEE's results is reduced after learning three to four key pieces of data about an oil field.[7] After learning the ten most important pieces of information about an oil field, there is typically little benefit to learning the remaining data.

Imprecise data reporting introduces additional uncertainty. Errors in applying the model can lead to further uncertainty.

The key variables to enhance model precision include: steam-to-oil and water-to-oil ratios, flaring rates, and crude density (measured as API gravity). Less important variables in the OPGEE model's ability to analyze GHG emissions include gas-to-oil ratios, oil production rates, and depth (except in extreme cases).

MODELING MIDSTREAM OIL EMISSIONS

REFINERIES ARE AKIN to a professional chef's kitchen. Instead of edible organic foodstuff, the ingredients are hydrogen, carbon, oxygen, and a multitude of impurities. Refinery equipment—effectively the stoves, refrigerators, pressure cookers, mixers, and bowls—heats, cleaves, blends, and reconfigures the massive flows of hydrocarbons it is fed.

Refining used to be a relatively simple process that involved applying heat to boil oil and separating it into its main components. But the changing nature of oil demands changes in refineries.

The changing nature of oil demands changes in refineries.

PRELIM is the first open-source refinery model that estimates energy and GHG emissions associated with various crudes processed in different refinery types using different processing equipment. It provides a more detailed investigation into the impacts crude quality and refinery configurations have on energy use and GHG emissions than what has been presented in the public realm to date. PRELIM can run a single crude or a blend of oils, and when combined with OPGEE, the model provides the second of the three components in the improved oil life-cycle assessment.

PRELIM influences the Oil-Climate Index in two important ways. It estimates midstream GHG emissions, and it predicts what petroleum commodities the refinery produces. The type and amount of products vary with a refinery's design.

MATCHING OILS TO REFINERIES

Every refinery is unique in terms of the combination of equipment it uses, the blends of crudes it is optimized for, and ultimately the type and amount of products it sells. Matching oil characteristics with refining infrastructure in order to meet end-use product demand is the midstream goal.

PRELIM attempts to represent many of these possible refinery configurations by including three different types of refinery—hydroskimming, medium conversion, or deep conversion—and ten combinations of processing units within refinery categories (see figure 5). One configuration, for example, employs a coking unit in a deep conversion refinery to reject high levels of carbon in the form of petcoke. Another example is configuring a refinery with hydrotreating for adding hydrogen.

The inputs and outputs of each refinery process unit are estimated using characteristics about individual process units from existing literature and industry-expert input as well as characteristics of the crude or crude blend.

Technically, each crude can be blended and processed in many different refinery configurations, but in practice crude oils are best matched to certain configurations. PRELIM selects the default refinery configuration that best suits a crude oil based on its properties (API gravity and sulfur content). This means that light and sweet (low sulfur) crudes will be processed in simpler refineries and heavy and sour (high sulfur) crudes will be directed to complex deep conversion refineries.

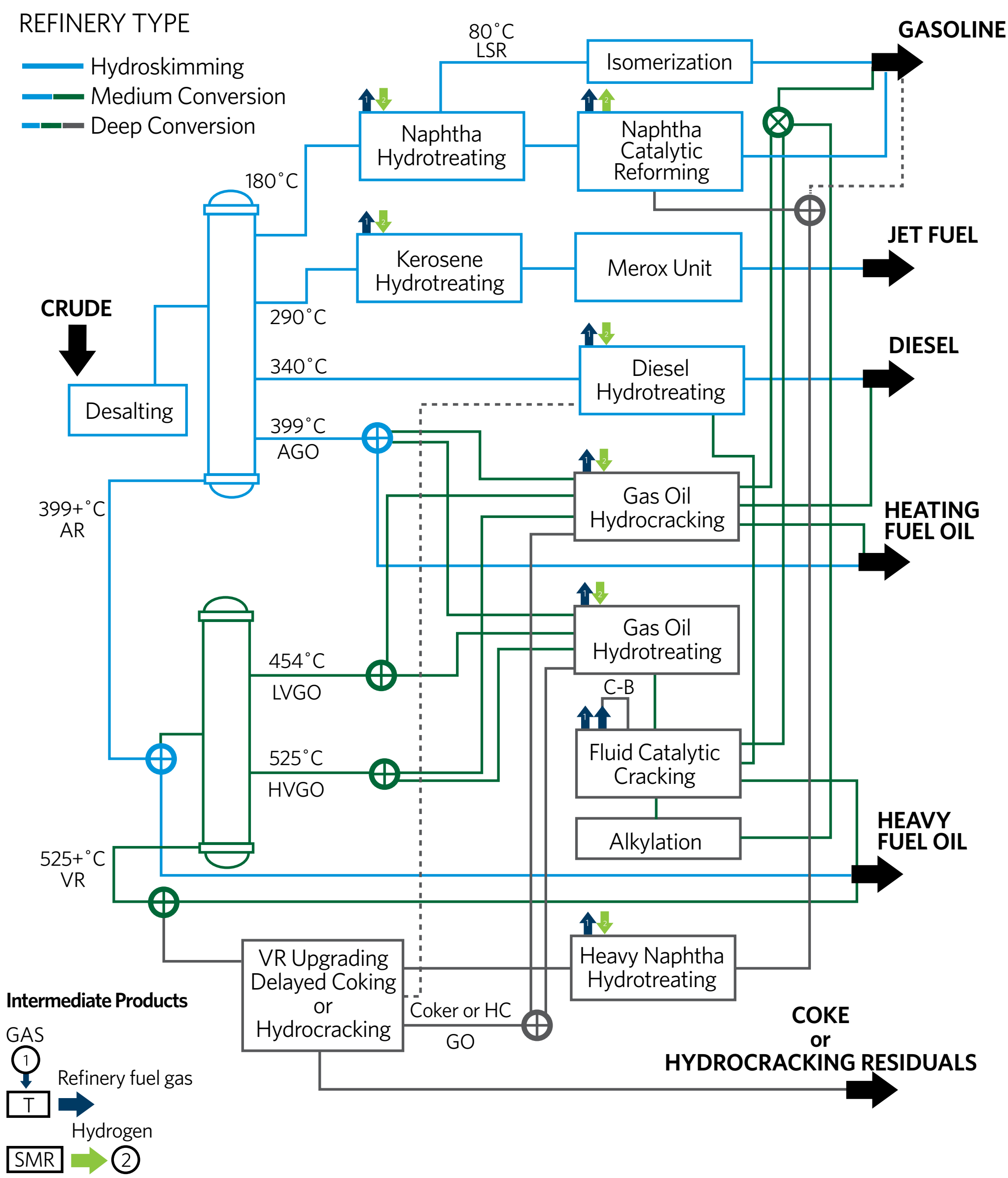
Specifically, PRELIM matches refineries with crudes as follows:

- Deep conversion refinery: heavy crude with any sulfur level
- Medium conversion refinery: medium sweet crude (22 to 32 API, with less than 0.5 percent sulfur content by weight); medium sour crude (22 to 32 API with more than 0.5 percent sulfur content by weight); and light sour crude (over 32 API with more than 0.5 percent sulfur content by weight)
- Hydroskimming refinery: light sweet crude over 32 API and less than 0.5 percent sulfur content by weight

While API gravity and sulfur are good indicators of a default refinery type, they are not sufficient to determine refinery GHG emissions. Therefore, the user of the model can override the default refinery configuration. For example, California Midway Sunset oil, with a reported API gravity as high as 22.6 and as low as the teens, was run through a deep conversion rather than a medium conversion refinery. Once the refinery configuration is selected, detailed information about the particular oil is needed well beyond API gravity and sulfur content of the whole crude.

FIGURE 5

Refinery Configurations in PRELIM



Source: Petroleum Refinery Life-Cycle Inventory Model

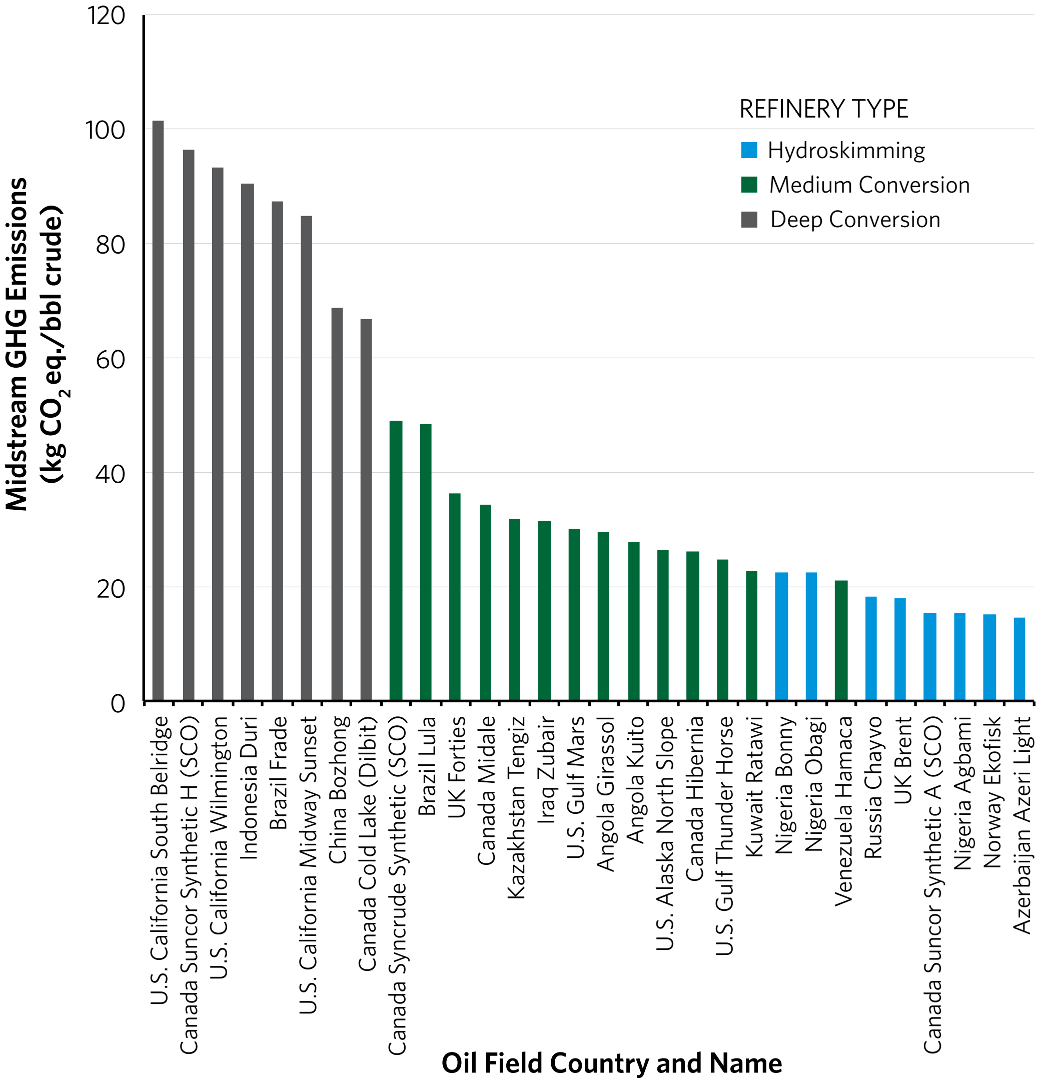
Note: See list of acronyms for more information.

PRELIM PHASE 1 RESULTS

During Phase 1, sufficient data were collected on 57 oils to run through PRELIM using a float case that allows the model to determine petroleum product yields rather than fixing production volumes.[8] The results for those 30 test oils where there was sufficient data to also run OPGEE show that midstream GHG emissions vary by a factor of seven (see figure 6).

FIGURE 6

PRELIM GHG Emission Results for 30 Phase 1 OCI Test Oils



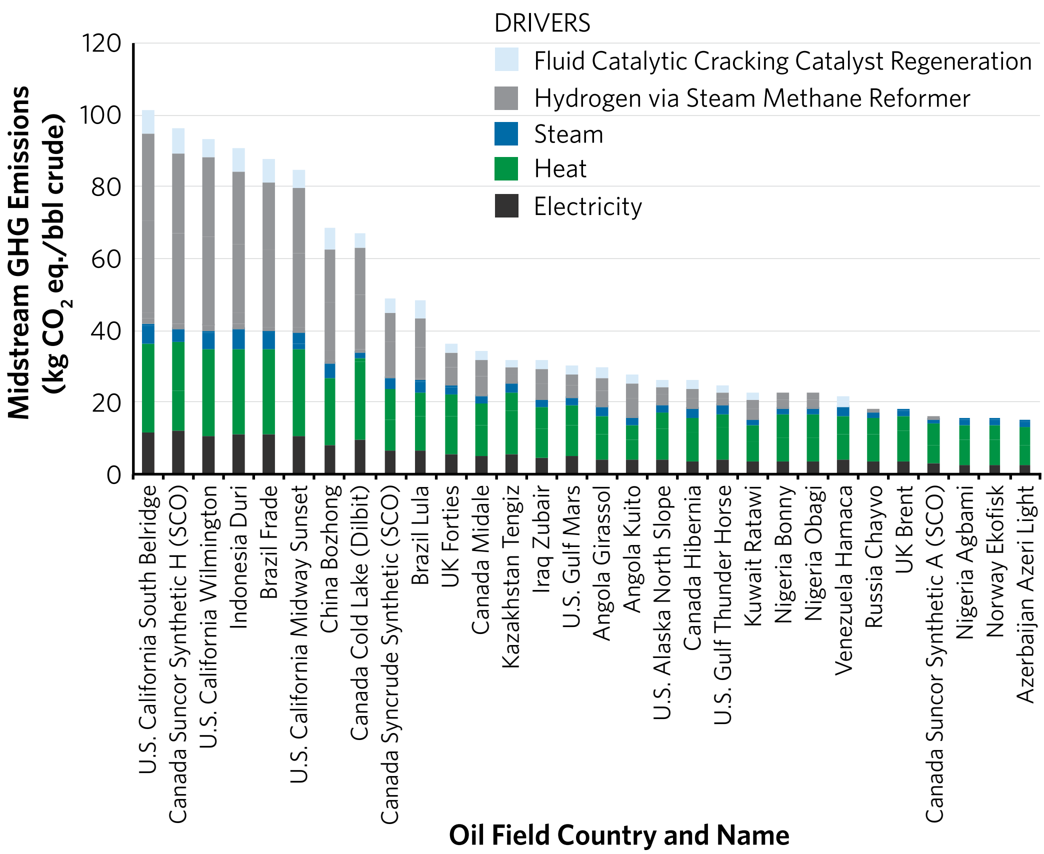
Source: Authors' calculations

Notes: The 30 test oils were run through a delayed coking refinery as well. Hydrocracking facilities are also possible to model in PRELIM. Medium and deep conversion refineries use fluid catalytic cracking (FCC) and gas oil-hydrocracking (GO-HC) processes. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

WHAT DRIVES MIDSTREAM EMISSIONS?

Recent work with PRELIM finds a number of factors that lead to high amounts of emissions during midstream petroleum operations (see figure 7). PRELIM is also useful in identifying where GHG emissions can be reduced in the refining process.

FIGURE 7
Drivers of Midstream GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

Crude quality and the selected process units employed (that is, the refinery configuration), as well as the energy efficiency of the process units, all play important roles in determining the energy requirements and emissions of an individual crude (or a crude blend).

The unique amount of hydrogen required to process each crude is the major driver of refinery energy use and GHG emissions. The amount is dictated by the quality of the crude entering the refinery. Lighter crudes yield more hydrogen when refined, while heavier crudes lack hydrogen and often utilize hydrogen inputs during refining.

Based on this analysis, the top three ways to reduce GHG emissions at refineries that process heavier crude are to reduce the amount of hydrogen consumed, increase hydrogen production efficiency (and/or lower the GHG emissions intensity of hydrogen production), and capture carbon dioxide from the most concentrated, highest volume refinery sources. Those sources include fluid catalytic cracking units used to produce additional gasoline and steam methane reformer units used to make hydrogen on-site from natural gas.[9]

PRELIM CHALLENGES

Many experts think that a crude oil's API gravity and sulfur content are reliable predictors of refinery GHG emissions. This, however, is a fallacy that has long hampered the collection of the full range of data needed to model midstream emissions.

OCI results illustrate this point. Ranking oils by their PRELIM emissions from high to low and plotting them in this order yields little or no correlation with API gravity (see figure 8). A similar mismatch results for sulfur and hydrogen content.

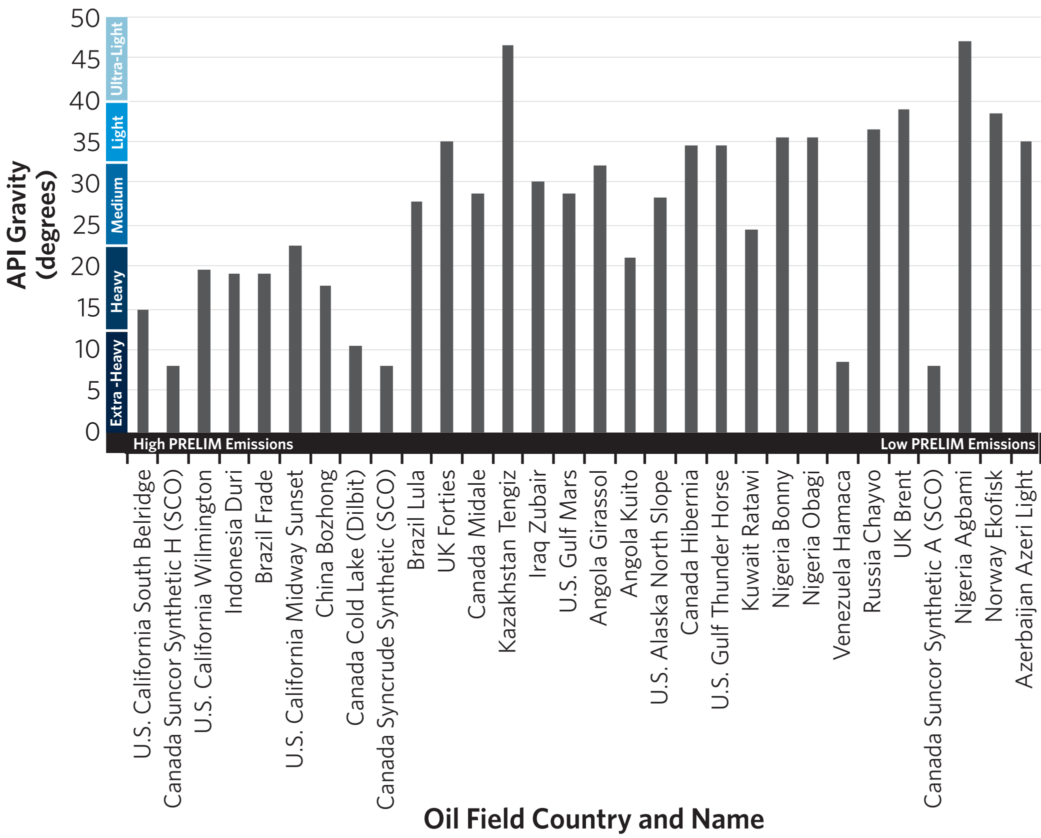
Similar to OPGEE, PRELIM faces typical LCA challenges such as data quality, transparency, and availability, as well as ambiguity associated with analysis boundaries and assumptions. Given the complexity and uniqueness of operating refineries and crudes produced around the world, any model that attempts to estimate refinery emissions will always include uncertainties. The major sources of uncertainty in PRELIM stem from gathering input data from the public realm and the fact that PRELIM results can be sensitive to many dynamic parameters.

Given the complexity and uniqueness of operating refineries and crudes produced around the world, any model that attempts to estimate refinery emissions will always include uncertainties.

An oil assay, or a chemical analysis of crude, reported in a consistent format is a particularly important PRELIM input. Assays provide extensive, detailed experimental data for refiners to establish the compatibility of a crude oil with a particular petroleum refinery. These data also determine if individual crudes fulfill market-driven product yield, quality, and demand, and they are used to determine if a refined crude will meet environmental, safety, and other standards. Assays guide plant operation, development of product schedules, and examination of future processing ventures. They supply

FIGURE 8

API Gravity of 30 Phase 1 OCI Test Oils in Order of PRELIM GHG Emissions



Source: Authors' calculations

engineering companies with crude oil analyses for their process design of petroleum refining plants, and they help determine companies' crude oil prices and set cost penalties for unwanted impurities and other undesirable properties.

PRELIM requires detailed oil assays that are routinely collected (specifics are available in the appendix).[10] Unfortunately, assay data reports are often inconsistent, lacking permission to use or reprint, or unavailable publicly at all. Standardized, updated, and consistent public oil assays that measure the same factors and abide by the same temperature cut points are needed to understand midstream oil emissions and product volumes that drive downstream emissions.

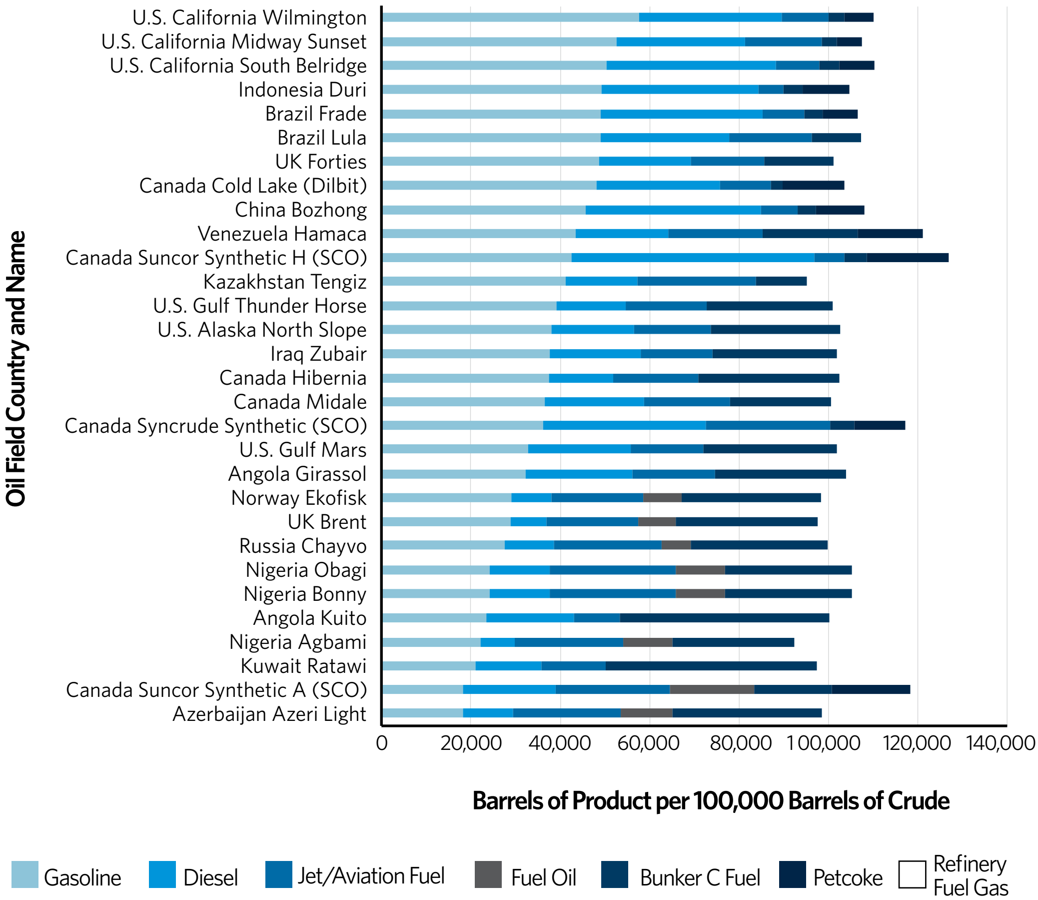
This situation calls for more robust oil data collection and reporting. Not only does such accuracy affect climate change impact estimates, it also can have safety impacts. Knowing an oil's characteristics can determine how to establish operating procedures for different oils when they move by rail, pipeline, and other transport modes.

MODELING DOWNSTREAM OIL EMISSIONS

THE TRANSPORTATION OF crude oil from the field to the refinery is captured in the OPGEE model. But there are also emissions from transporting petroleum products—gasoline, diesel, jet fuel, and other co-products—from the refinery outlet to domestic and global markets. This transport and use of refined petroleum products are the final inputs needed to calculate an oil's GHG emissions. OPEM uses the product outputs from PRELIM to calculate emissions from transport and end use (see figure 9).

The globalization of the oil sector has increased movement of these products in recent years. Refineries are no longer located predominantly in regions where demand is greatest. The United States, for example, has been refining a growing surplus of diesel fuel that it exports to Europe and Asia. Default values have been included in the Oil-Climate Index's downstream module according to a given route that petroleum products may take from Houston (where OPGEE assumes all crudes are refined) to the northeastern United States. This represents a lower bound for transport emissions; it does not consider long-distance international petroleum trade. The amount of GHG emissions from product transport varies depending on the methods used and distances traveled, but current OPEM defaults result in a lower bound of transport emissions at 1 to 2 percent of total emissions.

FIGURE 9
PRELIM Product Outputs for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: Petcoke production is total for refinery (for heavy oils) and upstream upgrading (for SCO). PRELIM currently assumes all refinery fuel gas (RFG) is used in the refining process. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

While transport emissions are minor relative to those stemming from other parts of the life cycle, end use dominates oil's GHG emissions. Prior LCA calculations have historically compared oil to alternative transport fuels.[11] As such, GHG emissions were measured predominantly on the basis of gasoline or diesel yields. But significant and variable emissions result from use of an oil's entire product slate, including petrochemical feedstock, which will be formally added to the product slate in OCI Phase 2, and bottom-of-the-barrel co-products like petcoke, fuel oil, bunker fuel (known as bunker C), and asphalt. This highlights the fact that the fate of the entire oil barrel is critical to understanding and designing policies that reduce an oil's GHG emissions.

PRODUCT TRANSPORT EMISSIONS

Three variables determine the emissions from the transportation of refined products: mode, distance, and the mass of the product. Different transport modes have different emission intensities.[12] If a tonne (metric ton) of fuel is shipped 1 kilometer, tanker trucks have the highest GHG emissions (0.09 kilograms of carbon dioxide equivalent per tonne-kilometer) while ocean-going crude carriers have the smallest emissions per tonne-kilometer (0.003 kilograms). Rail and pipeline emission factors are 0.02 and 0.01, respectively. For example, an average heavy-duty tanker truck moving a tonne of gasoline 1 kilometer emits as much as an ocean tanker moving a tonne 30 kilometers.

The energy needed and greenhouse gases emitted transporting refined products increases with distance and mass. PRELIM product outputs (converted from barrels to tonnes using reported product densities) are used to determine how much is transported to the marketplace; however, the distance that gasoline, diesel, jet fuel, petcoke, and other products are transported is difficult to determine. Limited and inconsistent data exist on the distances that products travel because there is no global agency or group to collect and audit such data. Collecting such data is also challenging because products are often shipped around the globe, trades tend to involve multiple actors that are frequently private firms, and product flows are highly dynamic, driven by changing supply and demand.

For the first phase of the Oil-Climate Index, default values for downstream product transport emissions represent a rough estimate of a typical (but not an average) distance traveled by truck and ocean tanker for the total mass of petroleum products for each crude. For example, default values of 2,414 kilometers (roughly 1,500 miles) by pipeline from Houston to the New York–New Jersey region and then 380 kilometers (about 236 miles) by tanker truck to the Boston region were selected.

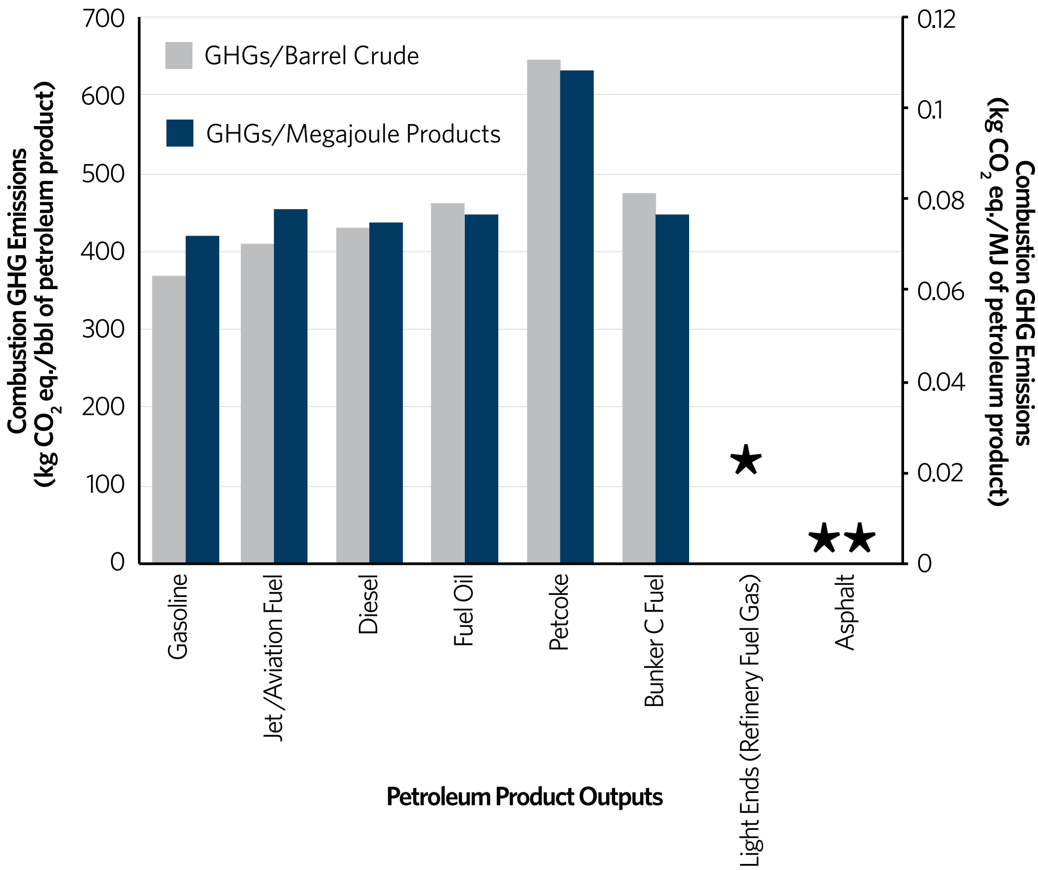
END-USE COMBUSTION EMISSIONS

Most hydrocarbon products are used to release energy to power cars, trucks, planes, trains, generators, and power plants. However, some petroleum products, like asphalt, hydrogen, and the refinery gases that make up petrochemical feedstock, derive their greatest economic value without being burned.

In order to calculate GHG emissions from petroleum product combustion for sample oils, each product's emission factor needs to be identified. The U.S. Environmental Protection Agency has been measuring, tracking, and updating emission factors since 1972.

Each barrel of combusted petroleum products has different emissions, ranging from gasoline at 370 kilograms of CO_2 equivalent per barrel to petcoke at 645 (see figure 10). The quantity of products produced from a given crude from PRELIM determines the overall emissions from combustion for that oil.

FIGURE 10
Petroleum Product Combustion-Related Emission Factors



Source: U.S. Environmental Protection Agency, "Emission Factors for Greenhouse Gas Inventories," www.epa.gov/climateleadership/documents/emission-factors.pdf

Notes: Emission factors most recently updated in April 2014.

* Light ends can be used as petrochemical feedstock, and refinery fuel gas (RFG) is a subset of light ends. When the resource is not combusted, it results in no GHG emissions; but when it is burned as RFG, it has an estimated emission factor ranging from 160 to 370 kilograms of CO_2 equivalent per barrel.

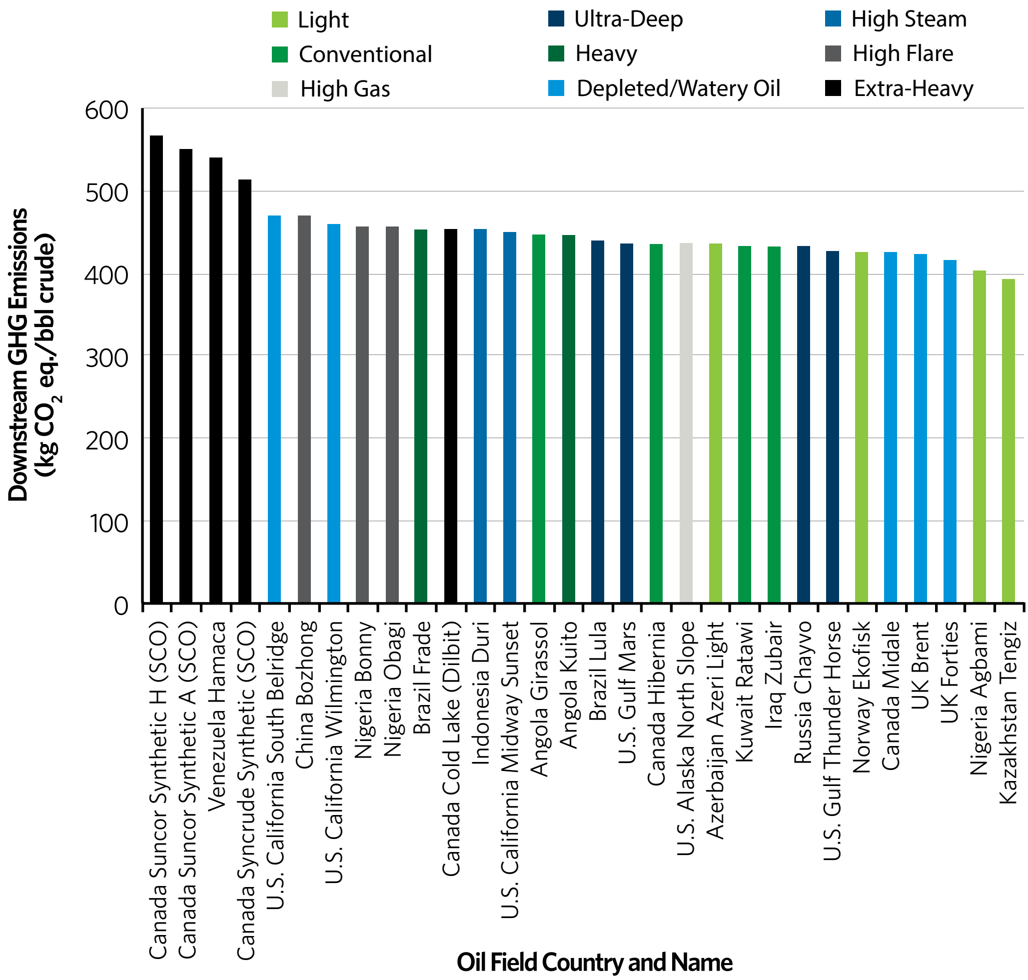
** Asphalt is not burned and, therefore, has no direct combustion emission factor when it is used to pave roadways, but it may result in emissions of up to 500 kilograms CO_2 equivalent per barrel product when heated for road oil or roofing or combusted for other uses.

OPEM PHASE 1 RESULTS

Although the downstream combustion of petroleum products accounts for the largest portion of overall emissions, there is variability between oils—a 45 percent spread between the combustion emissions of the 30 OCI test oils (see figure 11). The heaviest oils have higher combustion emissions while lighter oils have lower combustion emissions. Canada's Suncor Synthetic H synthetic crude oil (or SCO), an upgraded bitumen-based oil sand, has combustion emissions of nearly 565 kilograms of CO_2 equivalent per barrel of crude, whereas Kazakhstan Tengiz oil is estimated to yield a petroleum product slate that emits 390 kilograms per barrel. This range of absolute variation (155 kilograms CO_2 equivalent GHG emissions) is almost equal to the absolute range in upstream emissions shown in figure 3.

FIGURE 11

OPEM GHG Emission Results for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

OPEM CHALLENGES

The main uncertainties that arise regarding downstream emissions are related to product outputs from PRELIM. Combustion emission factors, which have been measured for decades, are updated routinely, and have less uncertainty associated with them, although as product specifications and engines change over time, so too will emission factors. And small changes in emission factors can lead to large changes in total emissions given large product output volumes.

Product transport emissions, meanwhile, are highly uncertain. But they are thought to be relatively small, except in possible extreme cases. The routes and distances different products take from the refinery to market are highly variable and largely opaque. Changing trade patterns are rarely disaggregated by product. Domestic as well as transnational petroleum product movements are often not made public. Without origin-to-destination data from refineries to end point, it is highly uncertain what modes and distances products travel and the emissions they cause.

OVERALL RESULTS FROM OCI PHASE 1

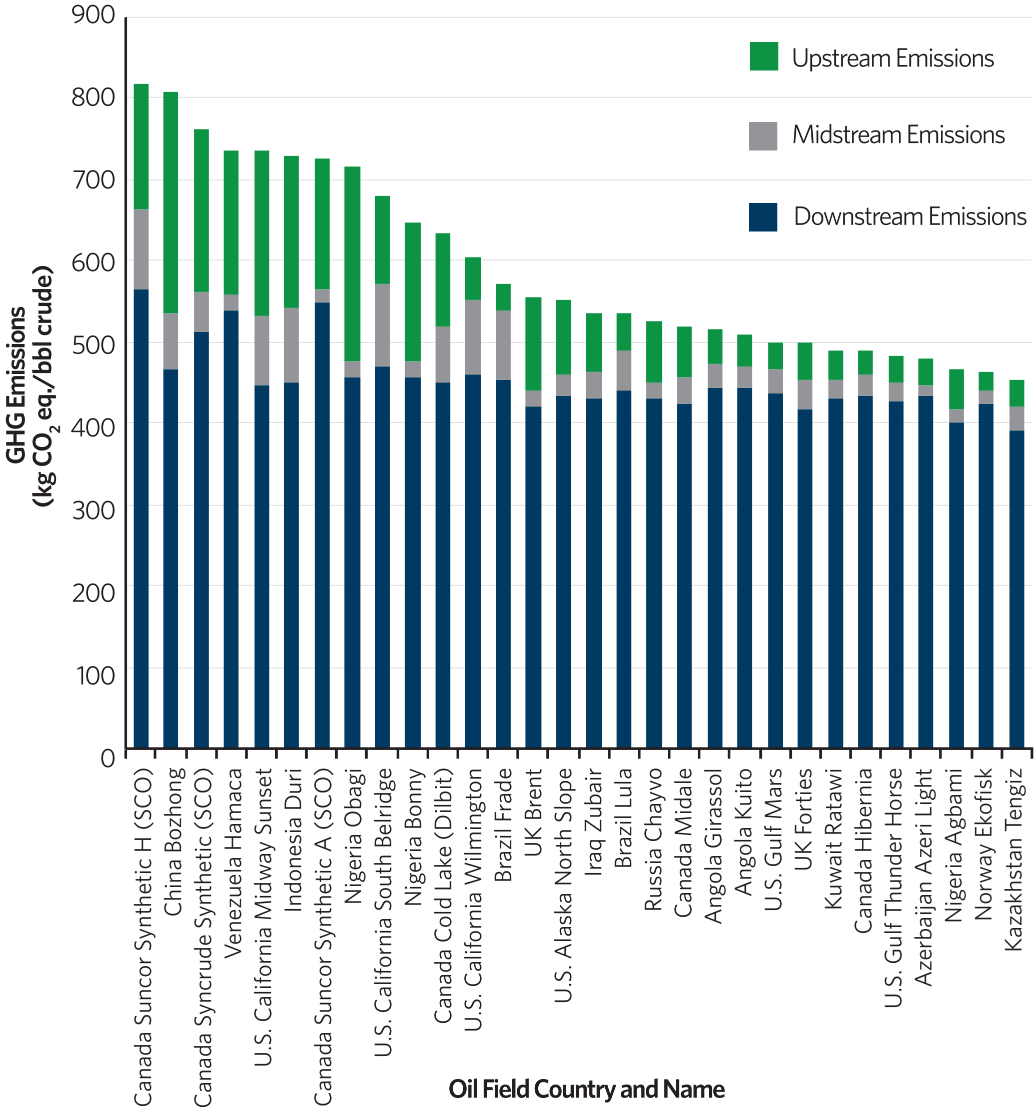
PUTTING THE PIECES of the Oil-Climate Index together results in the total GHG footprint for different oils. Results are reported per barrel of crude input (see figure 12). There is an over 80 percent difference between the highest GHG-emitting oil and the lowest on a per barrel basis. Since the selection of which oils to analyze in Phase 1 was influenced by data availability, it is impossible to know if this sample includes the full range of oils' emissions.

The share of total GHG emissions from different parts of the oil supply chain varies widely by oil. OPGEE emissions range from under 5 percent to 33 percent for different oils, PRELIM emissions range from 3 to 15 percent, and OPEM emissions range from 60 to 90 percent.

The Oil-Climate Index selects oil volume (per barrel of crude) as the default basis. But emissions are also reported per unit of energy (per megajoule of product), or by product value (in dollars of product) (see figure 13).

When emissions are calculated per megajoule or dollar value of petroleum products delivered, a similar, variable relationship holds as when measured per barrel of crude oil.

FIGURE 12
Total GHG Emissions for 30 Phase 1 OCI Test Oils



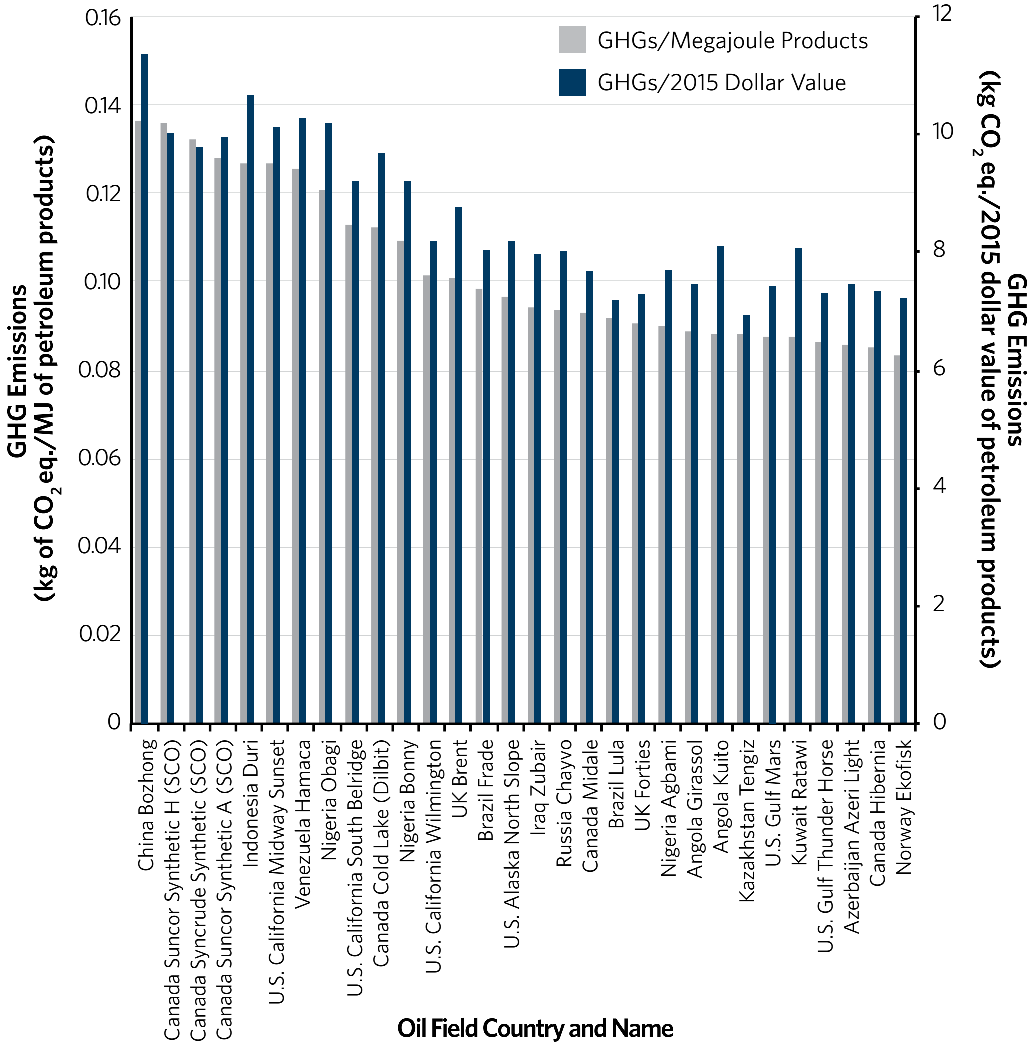
Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

The different functional units for comparing emissions—per barrel of oil, per megajoule of petroleum products, and per dollar value of petroleum products—reported in the index are all reasonably well correlated (see figure 14). In other words, those oils with greater per barrel GHG emission footprints, such as extra-heavy synthetic crude oils from Canada, heavier depleted oils from California, and highly flared oils from Nigeria, appear to also have higher emissions per U.S. dollar and per megajoule.

FIGURE 13

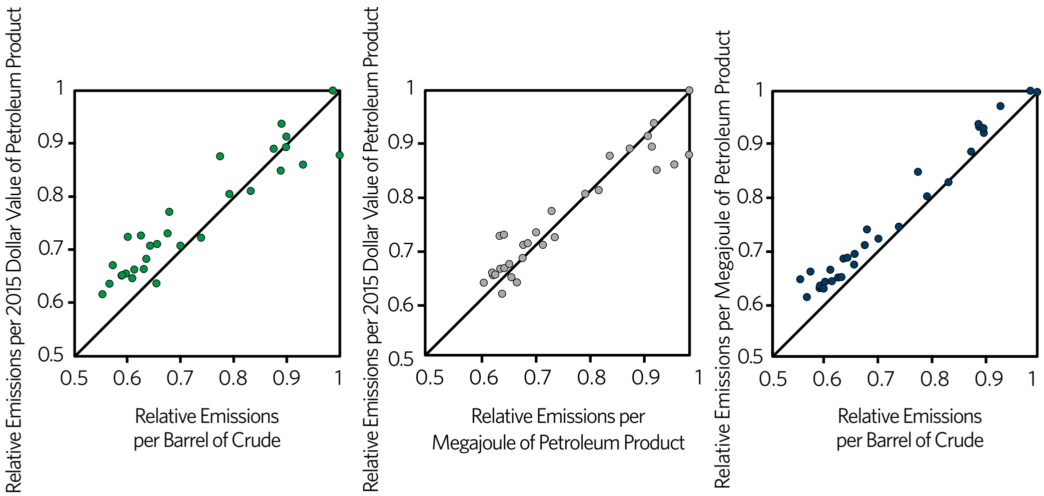
Total GHG Emissions per Megajoule (left) and per Dollar (right) for 30 Phase 1 OCI Test Oils



Sources: Authors' calculations; U.S. Energy Information Administration, "Spot Prices," February 9, 2015, www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; U.S. Energy Information Administration, "Refiner Petroleum Product Prices by Sales Type," February 9, 2015, www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm; and Argus Media Ltd., "Energy Argus: Petroleum Coke," July 2014, www.argusmedia.com/~/media/-Files/PDFs/Samples/Energy-Argus-Petroleum-Coke.pdf?la=en

Note: Petcoke prices are from 2014 data; all other petroleum products are from 2015 data. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

FIGURE 14
Parity Charts of OCI Functional Units for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: 1 equals highest value in all graphs. Petcoke prices are from 2014; all other petroleum products are from 2015 data.

FINDINGS AND RECOMMENDATIONS FROM OCI PHASE 1

THE OIL-CLIMATE INDEX was developed to alert stakeholders to the full array of climate impacts of oil from various perspectives, with an eye toward informing investment, development, operations, and governance of the oil supply chain. The index provides new knowledge that these stakeholders can take into account to make more informed, strategic, and durable decisions about oil development.

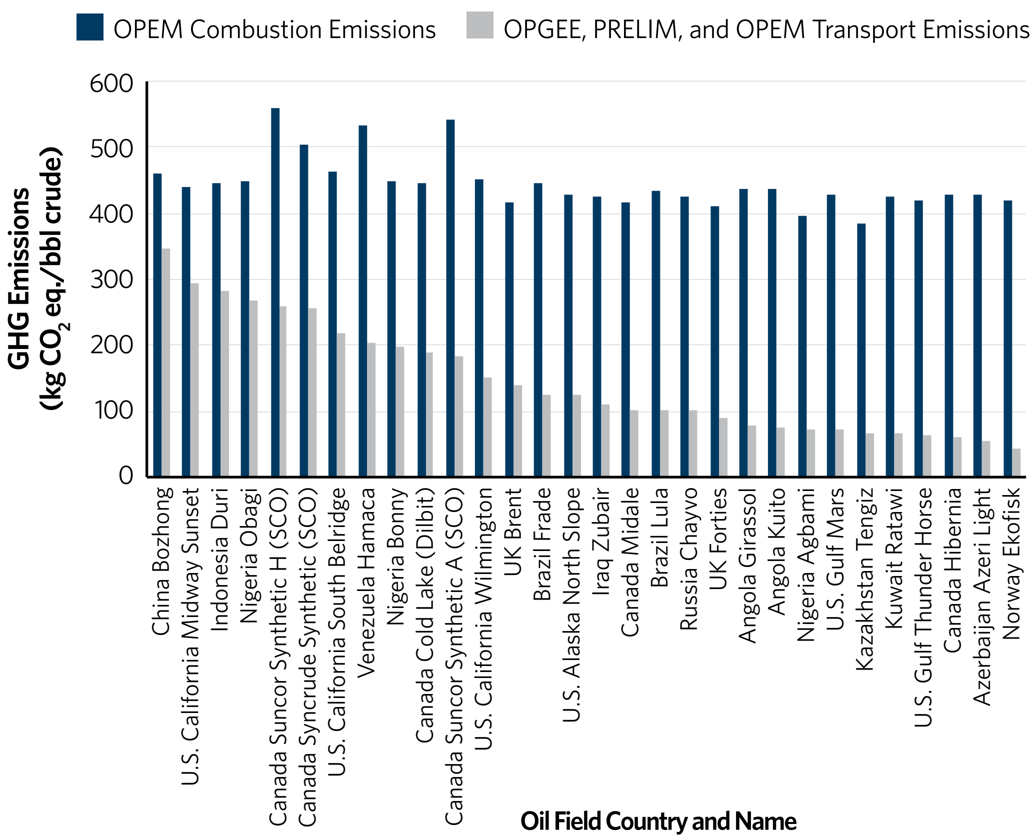
Investors, policymakers, and other stakeholders must evaluate oils based on their individual energy factors and GHG emissions, which vary significantly from oil to oil, and take this information into account when making public and private decisions.

KNOW YOUR OIL

For certain oils, the end products cast nearly as large a GHG footprint as the greenhouse gases produced to extract, refine, and transport them to market (see figure 15). Of the Phase 1 test oils, in addition to Canada Syncrude Synthetic (SCO) and China Bozhong, California Midway Sunset, Indonesia Duri, and Nigeria Obagi have some of the highest costs in climate terms.

Investors, policymakers, and other stakeholders must evaluate oils based on their individual energy factors and GHG emissions, which vary significantly from oil to oil, and take this information into account when making public and private decisions.

FIGURE 15
Comparing GHG Emissions of Oil Supply Chain Inputs and Outputs for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

OPEN-SOURCE INFORMATION IS KEY

New knowledge about oil is a critical ingredient for climate decisionmaking. As new oil and other oil-bearing hydrocarbon resources are discovered and technology advances to facilitate their development, new challenges will surface. If history is any guide, this information will likely be inconsistent and randomly reported by industry, governments, and the media. Intellectual property restrictions will limit the usability of data. And arbitrary restrictions on government data collection will make the task of full life-cycle assessment of emissions much more difficult.

Open-source information about oil should be made more accessible and widely available through reporting guidelines and regulatory reform that requires consistent, comparable, and verifiable data (see appendix for more details).

CREATE NEW OIL-CLIMATE CLASSIFICATIONS

Total GHG emissions are found to be generally higher in certain classes of oils. The Oil-Climate Index identifies three oil categories that (per barrel) result in higher GHG emissions than other oils: extra-heavy oils, oils whose associated gas is flared, and oils that are high in water or in largely depleted fields with large steam requirements during production (see table 2).

As oils become more unconventional over time, the number and types of oil classifications that are common today are likely to expand. For example, developments related to organic kerogen strewn throughout sedimentary rocks, oils buried in permafrost and elsewhere in the Arctic, bitumen trapped in solid carbonate formations or surrounded by water, turning coal or gas into liquid petroleum products, methane gas trapped in ice, or refinery designs that produce new types of petroleum products could require adding categories of oils to the index in the future.

TABLE 2

Designated Oil-Climate Categories for 30 Phase 1 OCI Test Oils

Light	Conventional	Ultra-Deep	High Gas	Heavy	Depleted/ Watery Oil	High Steam	High Flare	Extra-Heavy
Azerbaijan Azeri Light	Kuwait Ratawi	Russia Chayvo	U.S. Alaska North Slope	Angola Kuito	UK Brent	Indonesia Duri	China Bozhong	Canada Suncor Synthetic H (SCO)
Kazakhstan Tengiz	Canada Hibernia	Brazil Lula		Brazil Frade	U.S. California South Belridge	U.S. California Midway Sunset	Nigeria Obagi	Canada Suncor Synthetic A (SCO)
Norway Ekofisk	Angola Girassol	U.S. Gulf Mars			U.S. California Wilmington		Nigeria Bonny	Canada Syncrude Synthetic (SCO)
Nigeria Agbami	Iraq Zubair	U.S. Gulf Thunder Horse			UK Forties			Canada Cold Lake (Dilbit)
					Canada Midale			Venezuela Hamaca

THINK BEFORE BUILDING INFRASTRUCTURE

Because infrastructure lasts for generations, has opportunity costs, and has significant public impacts—as demonstrated by the debate over pipelines and refinery expansions—crudes should be compared before massive private investments are made in developing the increasingly diverse array of oil resources. It will also be important to analyze OCI impacts alongside shifting oil costs. Oil investments and their climate impacts need to be disaggregated by region, by oil, and throughout the oil supply chain.

To facilitate smart investment, stakeholders should improve the monitoring and reporting of oil capital expenditures in line with the OCI analysis as they relate to the GHG emissions expected for individual oil plays.

EXPLORE OPPORTUNITIES FOR GHG EMISSION REDUCTION

The GHG emissions from the 30 test oils run in OCI Phase 1 have a production-weighted average of 570 kilograms CO_2 equivalent per barrel oil. Emissions range from 450 to 820 kilograms CO_2 equivalent per barrel—nearly a difference of a factor of two in their climate intensity.

This wide range in GHG emissions opens the door for reducing the climate footprint of global oils. This could include extending current federal regulatory requirements for Environmental Impact Statements—documents prepared to describe the effects of proposed activities on the environment—to report oil assays and other OCI-relevant data during oil exploration. Low-emission oils could be slated for new development before high-GHG oils. There could be permit conditions placed on existing oil operations that bring high-GHG-emitting oils in line with average emitters. And employing best practices to improve operations, such as banning venting and nonemergency flaring, could reduce GHG emissions from existing oil supply chains.

Regulators and governments worldwide need to focus more on best practices to encourage producers, refiners, and traders to reduce greenhouse gases from high-emissions operations.

Upstream emissions—from exploration to production to oil transport to refining—have the greatest variability in their GHG emissions depending on venting, flaring, heat, and steam processing inputs. On the one hand, high-gas oils require infrastructure and operational expertise so they do not vent or flare their associated gas. On the other, oils that require significant heat and steam require more sophisticated methods to generate lower GHG inputs, such as co-generation, solar heat, and other techniques.

Regulators and governments worldwide need to focus more on best practices to encourage producers, refiners, and traders to reduce greenhouse gases from high-emissions operations. Different equipment, better handling, and improved management techniques will need to be employed over time to reduce GHG emissions.

Investors who choose to finance energy projects need to know what oils they are investing in. They should use their leverage to bring oil assays and other OCI-relevant oil data into the public domain and defer backing the development of high-GHG oils until technology is available or policies are adopted to reduce their climate footprints.

RECONCILE OIL ECONOMICS WITH GHG EMISSIONS

Oils' relative GHG emissions are not a major factor in the market price of crude oil, oil production costs, or the market value of the petroleum product slate from a given barrel of crude. Some crude oils with high GHG emissions, such as oil sands, are more expensive to produce, while others, such as high-GHG extra-heavy oils, are less expensive to produce. Still others, such as offshore U.S. Gulf of Mexico oil, have highly variable production costs but are not as GHG emission intensive.

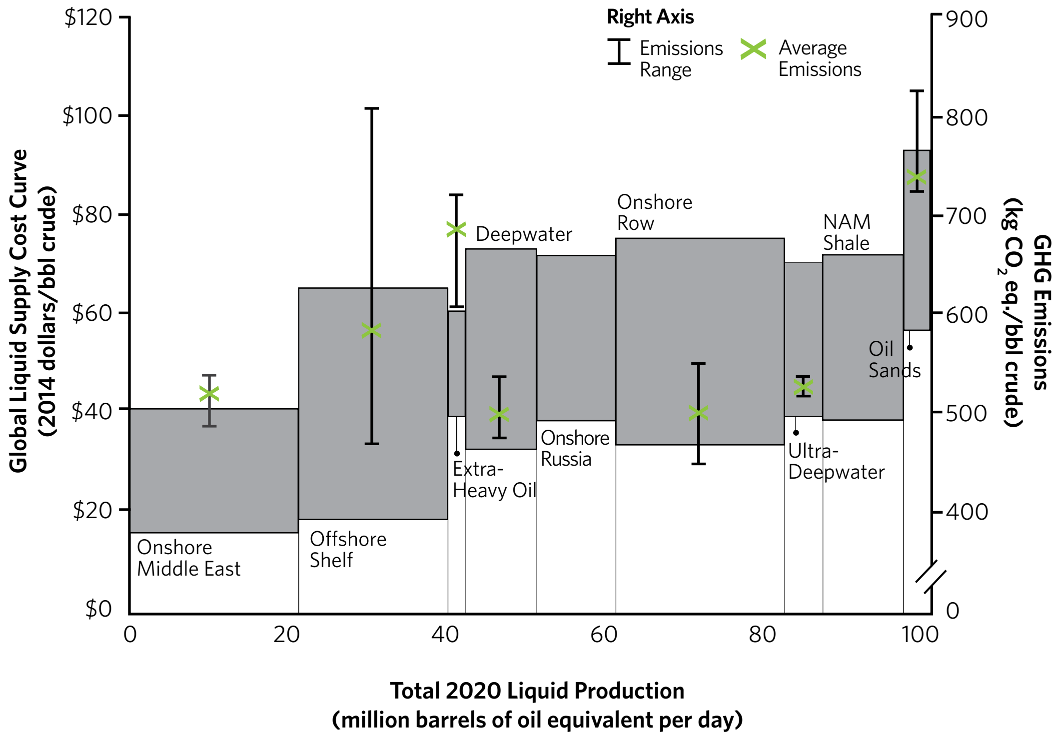
While it is difficult to access oil cost data, the limited or weak relationship between an oil's GHG emissions and its production cost factors used by Rystad Energy can be demonstrated (see figure 16). Comparing Rystad's production cost curve to the OCI GHG emission supply curve shows that production costs identified by industry oil categories do not align with social costs imposed by GHG emissions. Greater oil price transparency is necessary to fully assess the relationship between GHG emissions and oil prices.

Oil's economic and environmental performance may, in fact, trend in the wrong direction: the more valuable the product yield, the higher the oil's GHG emissions (see figure 17).

Climate policy must take into account the total GHG footprint of the oil supply chain. Otherwise, market forces will continue to override climate concerns.

Addressing this issue requires designing public policies (especially regulatory requirements for oil assays and OCI-related data that are needed to design carbon taxes and other policy mechanisms) to differentiate between global oils. Comprehensive upstream, midstream, and downstream emissions must be factored into climate policies—both current implicit shadow prices used by industry and investors and future explicit carbon taxes and other policies.

FIGURE 16
Oil Supply Cost Curve With GHG Emission Ranges for 30 Phase 1 OCI Test Oils



Sources: Rystad Energy (supply cost curve), authors' calculations (GHG emission ranges)

Note: The 30 Phase 1 OCI test oils did not contain any onshore Russian or North American (NAM) shale oils. If data permits, these oils will be added in OCI Phase 2 results.

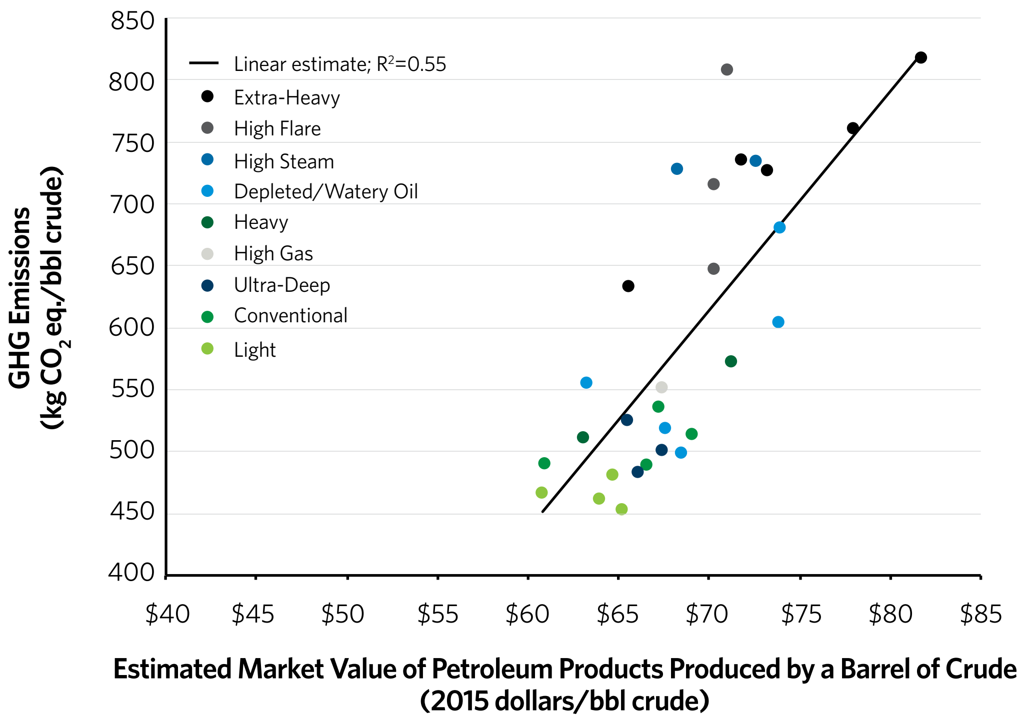
EXPAND THE OCI MODELS

The 30 test oils modeled in the Oil-Climate Index account for approximately 4.5 million barrels per day of production, or 5 percent of global output. Hundreds more oils remain to be evaluated.

In order to accurately compare oils, both those in current production and those poised for future production, the index must be expanded to include a greater number, array, and volume of global oils. It would also allow further analysis of oil types, emission ranges within oil categories, exploration of new oil categories, and identification of outliers.

This expansion begins with the underlying models. Their upgrade requires improved oil data collection (discussed more in the appendix), which in turn will lead to updating and fine-tuning OCI input models. Including more global oils and accounting for new upstream, midstream, and downstream operations are central to the OCI effort.

FIGURE 17
Market Value Versus GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Petcoke prices are from 2014; all other prices are from 2015.

Update OPGEE

Model verification needs to continue, which involves conducting tests with process simulation software. Real-world cases with operating data could still be used. In addition, an improved flaring analysis that more accurately uses global satellite flaring databases should be integrated because flaring is responsible for high GHG emissions from some gassy oils but not others. Real-time satellite data can determine which oils are flared and how much they are flared; this information is necessary to regulate and monitor these emissions. Flaring GHG emissions must be expanded beyond carbon dioxide to include black carbon formation and the treatment of fugitive methane emissions, which are often unintended and not adequately modeled.

Expand PRELIM

PRELIM will need to be updated and expanded to include a float case, crude blending, and hydrogen surplus credits from lighter oils. A more detailed assessment of refinery fuel gas, asphalt, and bunker fuel needs to be undertaken. Statistical analysis of actual refinery operations will be necessary to explore variability and uncertainty in order to further update the PRELIM model.

Update OPEM

Product flows must be further disaggregated to track actual refinery outputs and create smart defaults for transport emissions. Improved harmonization between oils and refineries must be built into these models. The refinery selected by OPGEE for a particular oil needs to align with the starting point of petroleum product transport in OPEM. Opportunities for policies and best practices should be explored to reduce GHG emission impacts from downstream transport and other oil uses.

BUILD OUT THE OCI WEB TOOL

A user-friendly OCI web tool has been developed by a team at the Carnegie Endowment for International Peace to inform stakeholders about the results of the modeling of the 30 test oils. The tool permits novice and experienced users alike to explore the index, inputting user-defined data or manipulating the underlying models themselves. In subsequent versions, new oils will be added to the web tool along with the updates to OPGEE, PRELIM, and OPEM detailed above.

This tool should be used to evaluate policies currently in force or under continued development, including oil emission intensity standards (for example, California's Low Carbon Fuel Standard Program and the European Union's Fuel Quality Directive). It can also be used to develop best practices (oil production and refinery operating decisions) and advance more targeted identification of high-GHG oils throughout the supply chain.

ADDRESSING TOMORROW'S OIL-CLIMATE CHALLENGES

DESPITE JOHN D. ROCKEFELLER'S successful corporate marketing, there is no standard oil. Likewise, there is no single GHG emission calculus that applies to oils overall. Tracing a GHG emissions supply curve that plots the 30 OCI test oils in terms of their current production volumes and GHG emissions shows how disaggregated oils are in terms of their climate impacts (see figure 18).

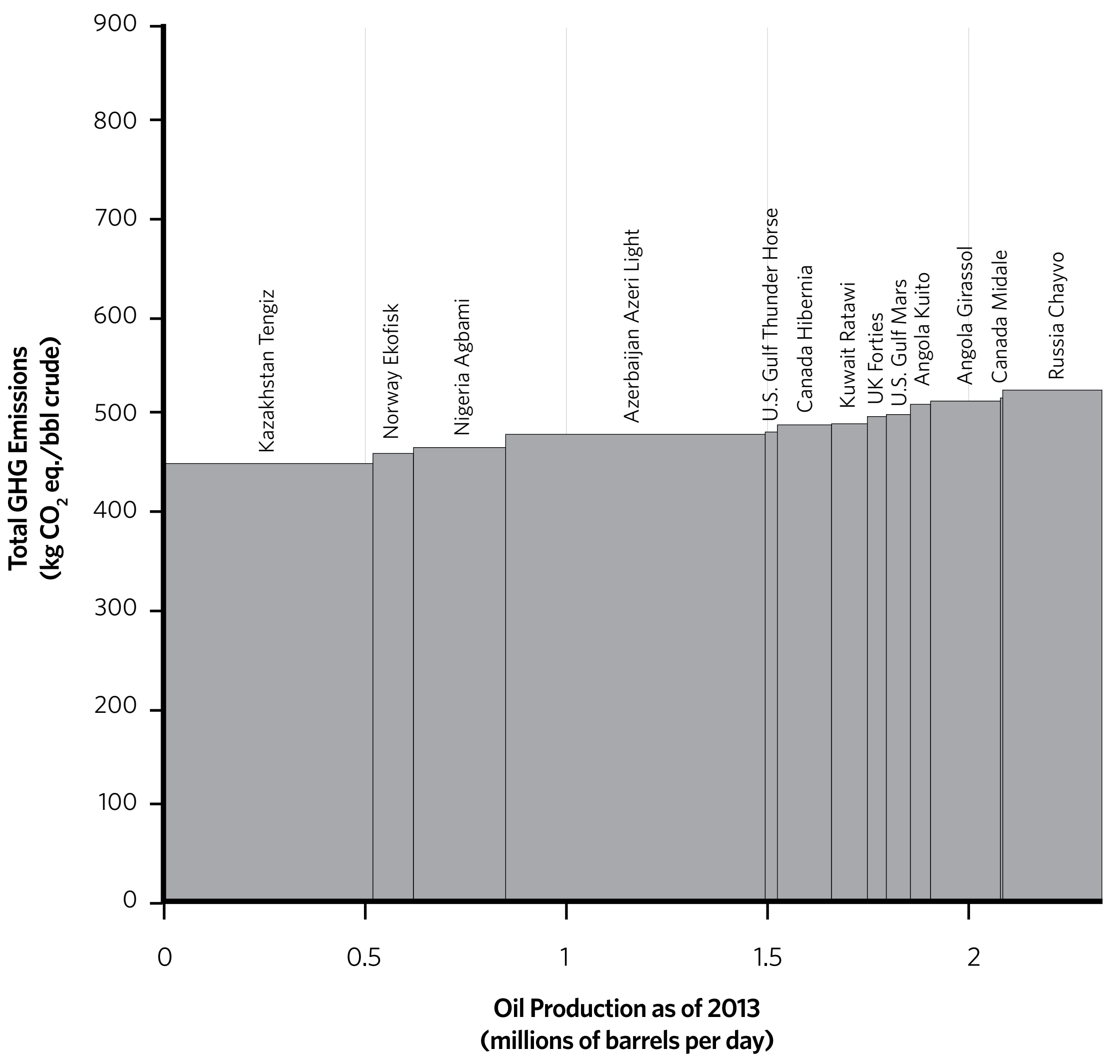
Throughout the twentieth century, conventional oils were more plentiful and homogeneous than today's unconventional resources. The technological capacity now exists to turn coal and natural gas into liquid petroleum products—in fact, some in China, Qatar, and elsewhere are already doing this. Plastics can be converted back into oil. Extreme heat can be used to accelerate geologic time and turn kerogen, deposited naturally in rocks, into diesel fuel. Abundant methane hydrate supplies—natural gas crystals frozen in the world's oceans and elsewhere—may someday be tapped and then transformed into liquid fuels.

With technology evolving to tap and transform diverse hydrocarbons into liquid oil resources, the oil business has expanded and greatly diversified. It now encompasses international oil companies, independent oil operators, national oil companies, traders, oligarchs, totalitarian regimes, and all governments across the world.

These advances will bring new opportunities and challenges. Reimagined enhanced oil recovery techniques that inject gases and liquids of all sorts will unearth heavier and more depleted oils. Refining innovations will change petroleum products and yield new oil co-products. Expanding refining capacity in China, Nigeria, Saudi Arabia, Singapore, and elsewhere will continue to shift product transport worldwide. Traders will increase their stake in the oil supply chain to benefit from arbitrage amid future oil market volatility.

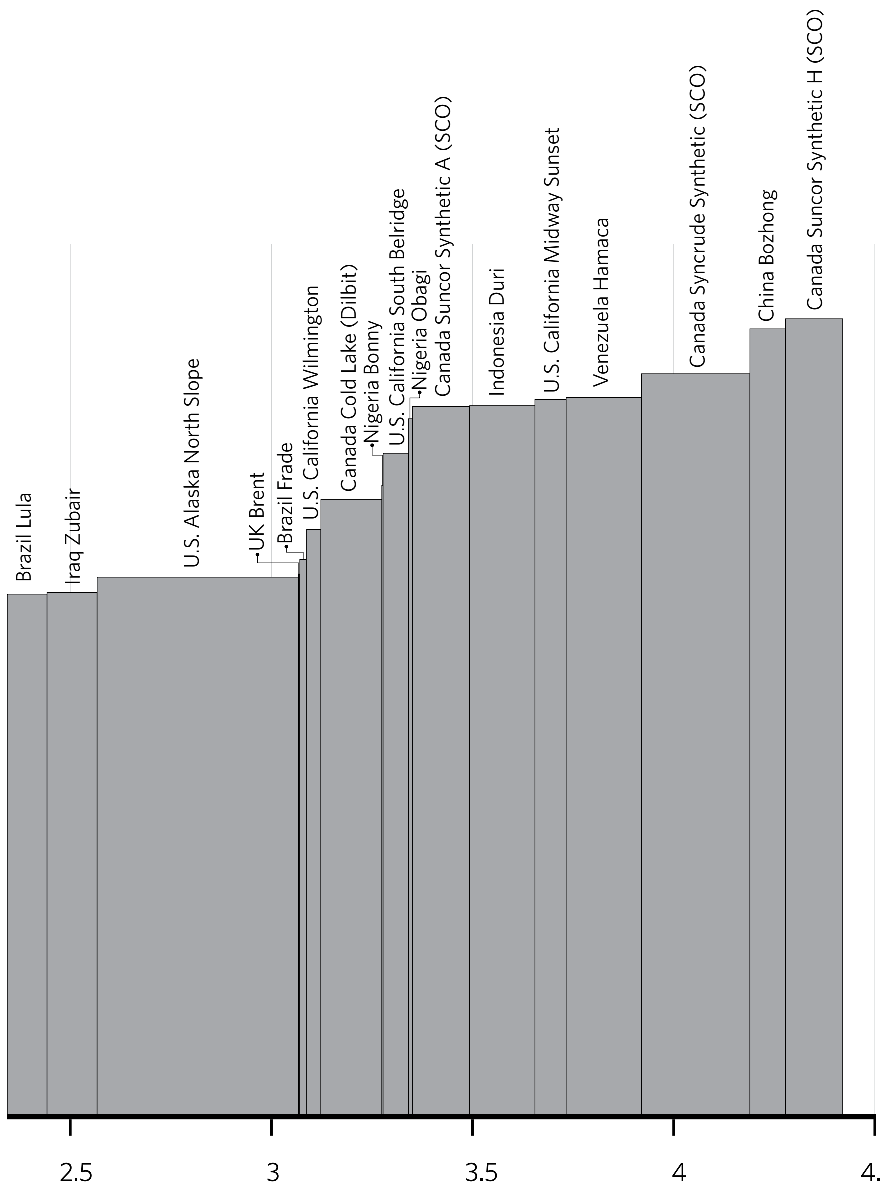
Meanwhile, in the twentieth century, climate change was not fully recognized as the major global threat it has since become. But global warming is now undeniably a matter of public record.

FIGURE 18
Oil-Climate Index Emissions Supply Curve for 30 Phase 1 OCI Test Oils



Tomorrow, oils will compete fiercely against other oils for market share in a warming world. In fact, this struggle has already begun. Oil markets are reeling as supplies are maintained in the face of softening global demand, and the Organization of the Petroleum Exporting Countries (OPEC) and North America (the United States, Canada, and Mexico) each expect the other to cut back production.

The progression from simpler to more complex oil value chains calls for more information, smarter decisionmaking, and sound policy guidance. The Oil-Climate Index offers



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

the means to comprehensively compare oils so climate impacts can be factored into financing, development, operating, and government oversight decisions. All stakeholders need better information about the GHG emissions embodied in the oil supply chain in order to avoid unintended climate consequences.

All stakeholders need better information about the GHG emissions embodied in the oil supply chain in order to avoid unintended climate consequences.

The large divergence in the climate impacts of global oils underscores the need to pick and choose wisely among resource options. End-use strategies that reduce the combustion of petroleum products—such as improved vehicle fuel efficiency, greater use of alternative fuels, and new mobility options—will no doubt be critical. But demand-side strategies, while necessary, are not sufficient. Oil supply-side strategies must contribute to the solution set as well.

Investors and industry need to make durable asset valuations and infrastructure decisions that will not be stranded by future climate policies and outcomes. Policymakers need up-to-date knowledge to approve permits, set standards, price carbon, and adopt better governance practices overall. And the public needs robust open-source information about oil to better understand the trade-offs between global oils in order to make wise energy choices.

The Oil-Climate Index can shape how consumers and industry approach future oil production and can guide the policies used to address oil-climate concerns. The first phase of the index highlights the large variation in GHG emissions between global oils. Incorporating the index into private and public decisionmaking and expanding this tool to account for a greater share of global oils are critical to reducing the climate impacts of the oil sector.

APPENDIX: OIL DATA GAPS

OIL MARKETS CANNOT function efficiently without transparent, high-quality information. Comprehensive information is also a necessary condition for effective policymaking. Oils' inherent chemical characteristics, their operational specifications, and how they differ from one another under varying sets of conditions are critical informational inputs.

In seeking to obtain and verify these needed oil data, several obstacles have been encountered:

- Oil data inconsistencies: There are hundreds of different global oils and no standardized format for oil assays. This makes it virtually impossible to compare oils.
- Data cannot be used without companies' permission: The oil industry publishes assays, and the fine print can present problems. For example, users who wish to comply with companies' policies have to obtain permission to reproduce oil data in any format. Therefore, some of the oil data that is available for viewing is not truly "open source" in practice.
- Data is not for sale: Up-to-date, comprehensive oil databases are held by the private sector, often oil consultancies. The price to obtain oil data is typically very high. But even if think tanks and academics can afford the hundreds of thousands of dollars to purchase oil data, it is not necessarily for sale. For example, after lengthy negotiations, a firm would not sell oil data even to academic scholars who were viewed as competitors.

- Government limitations to collecting data: The U.S. Department of Energy is limited in its reach to expand oil-reporting requirements. For example, one of the authors was told that the department could not establish consistent reporting requirements for oil data because the U.S. Office of Management and Budget considers oil data collection a duplication of effort from a budgetary perspective. This means that policymakers and the public are at the behest of industry to divulge information that may not be timely, accurate, or consistent.

Publicly available information, at a minimum, must contain expanded data collection as summarized in the figure below.

Open Source Oil-Climate Modeling

OPGEE *(Oil Production Greenhouse Gas Emissions Estimator)*
Upstream Production Data

1. Extraction method specifications *(primary, secondary, EOR, other)*
2. Level of activity per unit production
    - Water-to-oil ratio *(for primary and secondary production)*
    - Steam-to-oil ratio *(for tertiary production)*
3. Location *(onshore, offshore, with GIS coordinates)*
4. Flaring rate
5. Venting rate *(level of fugitive emissions)*

PRELIM *(Petroleum Refinery Life-Cycle Inventory Model)*
Midstream Refining Data

1. Reporting on updated refinery process energy requirement data
2. Refinery changes that affect petroleum product specifications and quality *(especially for bottom- and top-of-the-barrel products that are not regulated for use in vehicle engines)*
3. Oil assay parameters (specified below) and reported consistently for each global oil

Each parameter (except MCR/CCR) must be specified at each cut temperature, and cut temperature ranges must be standardized, as specified below or in another consistent format.

Note: Cut temperatures are currently reported out using a variety of inconsistent formats.

- API Gravity
- Density
- Sulfur content (wt %)
- Nitrogen content (mass ppm)
- Hydrogen content
- Volume/Mass Flow (% recovery)
- Micro-carbon residue (MCR) or Conradson carbon residue (CCR)
- Viscosity (cST at 100 °C) for Vacuum Residuum

*The cut temperatures and products currently used in the PRELIM refining model are:

Temperature	Product Cut Name
80 °C	Light Straight Run
180 °C	Naphtha
290 °C	Kerosene
343 °C	Diesel
399 °C	Atmospheric Gas Oil (AGO)
454 °C	Light Vacuum Gas Oil (LVGO)
525 °C	Heavy Vacuum Gas Oil (HVGO)
525+ °C	Vacuum Residue (VR)
399+ °C	Atmospheric Residue (AR)

OPEM *(Oil Products Emissions Module)*
Downstream Transport and Combustion Data

1. Global oil trade statistics
   (by crude, product, mode, and region)
2. Annual mapping of changing trade patterns and trends
   (disaggregated by the full spectrum of petroleum products)
3. Domestic (in-country) oil and petroleum product transfers
   (GIS coordinates from refinery gate or shipping hub to end use)
4 Origin data (crudes) and destination data (individual petroleum products), by refinery
5. Market prices for all oil products
   (petrochemical feedstocks, condensates, petroleum coke (petcoke), bunker fuel, fuel oil #4, asphalt, and other marketable refined products)

NOTES

1 Christophe McGlade and Paul Ekins, “The Geographical Distribution of Fossil Fuels Unused When Limiting Global Warming to 2 °C,” *Nature* 517, no. 7533 (2015): 187–90, http://dx.doi.org/10.1038/nature14016.

2 Jonathan Koomey, “Moving Beyond Benefit-Cost Analysis of Climate Change,” *Environmental Research Letters* 8, no. 041005, December 2, 2013, http://iopscience.iop.org/1748-9326/8/4/041005; Malte Meinshausen, Nicolai Meinshausen, William Hare, Sarah C. B. Raper, Katja Frieler, Reto Knutti, David J. Frame, and Myles R. Allen, “Greenhouse-Gas Emission Targets for Limiting Global Warming to 2 Degrees C,” *Nature* 458 (April 30, 2009): 1158–62, www.nature.com/nature/journal/v458/n7242/full/nature08017.html; University College of London, “Which Fossil Fuels Must Remain in the Ground to Limit Global Warming?” January 7, 2015, www.ucl.ac.uk/news/news-articles/0115/070115-fossil-fuels; http://unfccc.int/resource/docs/2009/cop15/eng/l07.pdf.

3 OPGEE was developed by Hassan El-Houjeiri, Kourosh Vafi, Scott McNally, and Adam Brandt at Stanford University. Significant assistance was provided by James Duffy of the California Air Resources Board. The State of California adopted OPGEE, the first open-source GHG emissions tool for oil and gas operations, through rulemaking for the development of California’s Low Carbon Fuel Standard in November 2012. New OPGEE versions have since been released. The version of OPGEE used in generating this report is OPGEE version 1.1 draft D. For the OPGEE User Guide and Technical Documentation see https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator.

4 PRELIM was developed by Jessica Abella, Kavan Motazedi, and Joule Bergerson at the University of Calgary. The following individuals and institutions have been involved in the development of the open-source PRELIM model: researchers on the LCAOST project including Professor Heather MacLean; Natural Resources Canada; Alberta Innovates: Energy and Environment Solutions; Carbon Management Canada; National Science and Engineering Research Council of Canada; Carnegie Endowment for International Peace; LCAOST Oil Sands Industry Consortium. For PRELIM User Guide and Technical Documentation see http://ucalgary.ca/lcaost/PRELIM.

5 "Worldwide Refineries—Capacities as of Jan. 1, 2014," *Oil & Gas Journal*, December 31, 2014.

6 Emissions are calculated according to the displacement of like products by energy value. Any natural gas produced and then exported off-site is assumed to displace average natural gas emissions calculated in the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) model. Any electricity generated on-site displaces GREET natural gas-based electric power.

7 See the following papers for analysis of OPGEE estimate improvement with increasing data availability: A. R. Brandt, Y. Sun, and K. Vafi, "Uncertainty in Regional-Average Petroleum GHG Intensities: Countering Information Gaps With Targeted Data Gathering," *Environmental Science & Technology*, DOI: 10.1021/es505376t, 2014; K. Vafi, A. R. Brandt, "Uncertainty of Oil Field GHG Emissions Resulting From Information Gaps: A Monte Carlo Approach," *Environmental Science & Technology*, DOI: 10.1021/es502107s, 2014.

8 The "fixed" case, where the volumes of final products are set and the amount of input crude varies to provide the final product slate, is currently in development. The "fixed" case will be capable of either fixing the gasoline to diesel ratio or a specific set of final product volumes.

9 Jessica P. Abella and Joule A. Bergerson, "Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration," *Environmental Science & Technology* 46, no. 24 (2012): 13037–13047, DOI: 10.1021/es3018682, http://pubs.acs.org/doi/abs/10.1021/es3018682.

10 Incomplete assays containing as few as four fractions and high-temperature simulated distillation (HTSD) curves can be put into PRELIM, but this introduces uncertainty that can affect emission outputs.

11 Pioneers in this field include: Argonne National Laboratory GREET Lifecycle Model (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model), https://greet.es.anl.gov; Lifecycle Associates, www.lifecycleassociates.com; Natural Resources Canada GHGenius Model, www.ghgenius.ca; International Council on Clean Transportation, www.theicct.org/info/assets/RoadmapV1/ICCT%20Roadmap%20Model%20Version%201-0%20Documentation.pdf; Jacobs Consultancy, http://eipa.alberta.ca/media/39640/life%20cycle%20analysis%20jacobs%20final%20report.pdf; and others.

12 GREET 1 2013, sheet "EF," Table 2.3, "Emission Factors of Fuel Combustion: Feedstock and Fuel Transportation From Product Origin to Product Destination Back to Product Origin (Grams per mmBtu of Fuel Burned)," Energy Intensities were taken from GREET 1 2014 on the properties page "Step Parameters" for each mode of transport, respectively.

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Attachment 20

Attachment 20. *Refinery Crude Oil Input Qualities;* Data from US EIA for the years 2009–2014.
Available from Web Page: http://www.eia.gov/petroleum/data.cfm

Weighted averages

Year	East Coast (PADD 1) Sulfur (wt. %)	East Coast (PADD 1) API Gravity	East Coast (PADD 1) *d* (kg/m^3)	Midwest (PADD 2) sulfur (wt.%)	Midwest (PADD 2) API Gravity	Midwest (PADD 2) *d* (kg/m^3)
2009	0.76	32.45	863	1.31	32.76	861
2010	0.65	33.48	858	1.26	33.27	859
2011	0.71	33.09	860	1.34	33.24	859
2012	0.84	33.41	858	1.37	33.14	859
2013	0.76	34.46	853	1.45	33.16	859
2014	0.86	34.29	853	1.47	32.92	861

Year	Gulf Coast (PADD 3) Sulfur (wt. %)	Gulf Coast (PADD 3) API Gravity	Gulf Coast (PADD 3) *d* (kg/m^3)	Rocky Mountain states (PADD 4) sulfur (wt.%)	Rocky Mountain states (PADD 4) API Gravity	Rocky Mountain states (PADD 4) *d* (kg/m^3)
2009	1.61	29.55	879	1.41	33.10	860
2010	1.58	29.94	876	1.33	33.42	858
2011	1.54	30.00	876	1.37	33.19	859
2012	1.53	30.66	873	1.37	33.68	857
2013	1.54	30.00	876	1.42	33.85	856
2014	1.54	31.81	866	1.33	33.71	856

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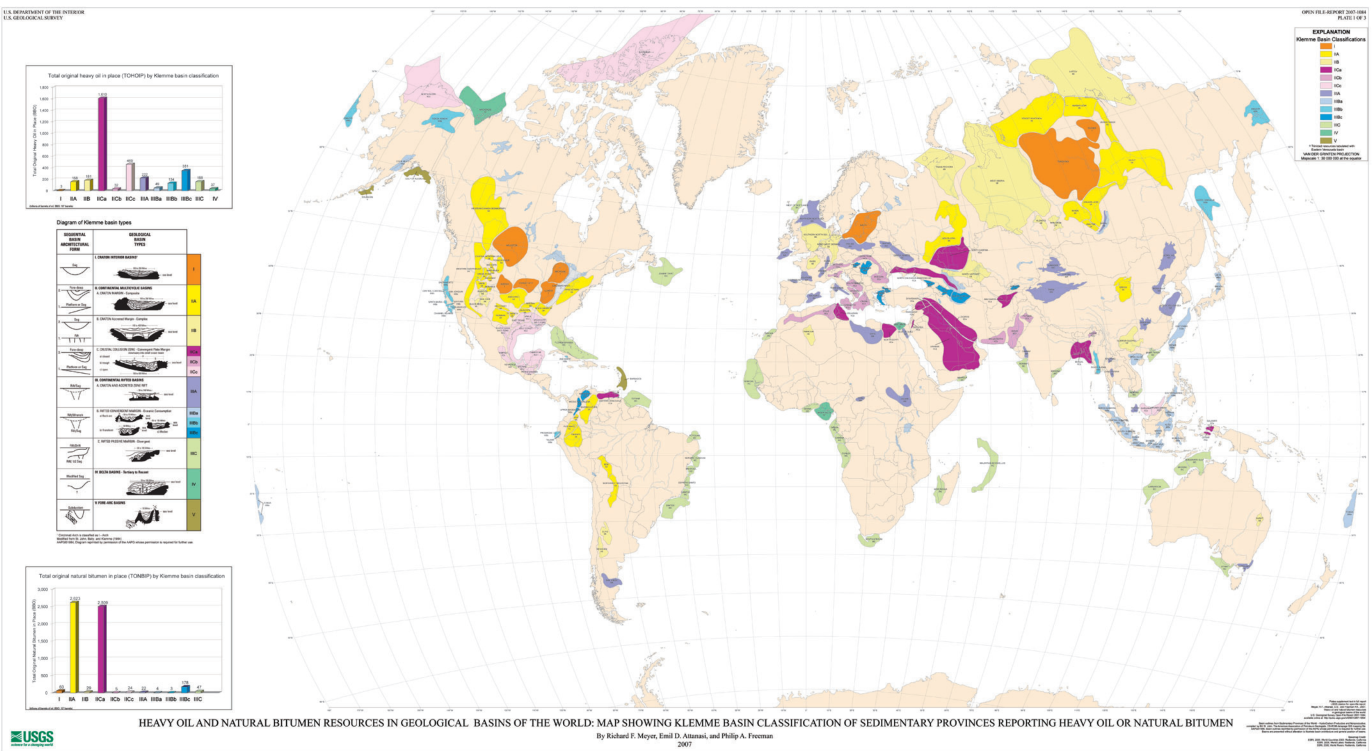
Heavy Oil and Natural Bitumen Resources in Geological Basins of the World



Open File-Report 2007-1084

U.S. Department of the Interior
U.S. Geological Survey

Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

Open File-Report 2007–1084

U.S. Department of the Interior
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Suggested citation:
Meyer, R.F., Attanasi, E.D., and Freeman, P.A., 2007, Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084, available online at http://pubs.usgs.gov/of/2007/1084/.

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(available online at http://pubs.usgs.gov/of/2007/1084)

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Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

Abstract

Heavy oil and natural bitumen are oils set apart by their high viscosity (resistance to flow) and high density (low API gravity). These attributes reflect the invariable presence of up to 50 weight percent asphaltenes, very high molecular weight hydrocarbon molecules incorporating many heteroatoms in their lattices. Almost all heavy oil and natural bitumen are alteration products of conventional oil. Total resources of heavy oil in known accumulations are 3,396 billion barrels of original oil in place, of which 30 billion barrels are included as prospective additional oil. The total natural bitumen resource in known accumulations amounts to 5,505 billion barrels of oil originally in place, which includes 993 billion barrels as prospective additional oil. This resource is distributed in 192 basins containing heavy oil and 89 basins with natural bitumen. Of the nine basic Klemme basin types, some with subdivisions, the most prolific by far for known heavy oil and natural bitumen volumes are continental multicyclic basins, either basins on the craton margin or closed basins along convergent plate margins. The former includes 47 percent of the natural bitumen, the latter 47 percent of the heavy oil and 46 percent of the natural bitumen. Little if any heavy oil occurs in fore-arc basins, and natural bitumen does not occur in either fore-arc or delta basins.

Introduction

Until recent years conventional, light crude oil has been abundantly available and has easily met world demand for this form of energy. By year 2007, however, demand for crude oil worldwide has substantially increased, straining the supply of conventional oil. This has led to consideration of alternative or insufficiently utilized energy sources, among which heavy crude oil and natural bitumen are perhaps the most readily available to supplement short- and long-term needs. Heavy oil has long been exploited as a source of refinery feedstock, but has commanded lower prices because of its lower quality relative to conventional oil. Natural bitumen is a very viscous crude oil that may be immobile in the reservoir. It typically requires upgrading to refinery feedstock grade (quality). When natural bitumen is mobile in the reservoir, it is generally known as extra-heavy oil. As natural asphalt, bitumen has been exploited since antiquity as a source of road paving, caulk, and mortar and is still used for these purposes in some parts of the world. The direct use of mined asphalt for road paving is now almost entirely local, having been replaced by manufactured asphalt, which can be tailored to specific requirements.

This study shows the geological distribution of known heavy oil and natural bitumen volumes by basin type. These data are presented to advance a clearer understanding of the relationship between the occurrence of heavy oil and natural bitumen and the type of geological environment in which these commodities are found. The resource data presented were compiled from a variety of sources. The data should not be considered a survey of timely resource information such as data published annually by government agencies and public reporting services. With the exception of Canada, no such data source on heavy oil and natural bitumen accumulations is available. The amounts of heavy oil yet unexploited in known deposits represent a portion of future supply. To these amounts may be added the heavy oil in presently poorly known and entirely unexploited deposits. Available information indicates cumulative production accounts for less than 3 percent of the discovered heavy oil originally in place and less than 0.4 percent of the natural bitumen originally in place.

Terms Defined for this Report

- Conventional (light) Oil: Oil with API gravity greater than 25°.
- Medium Oil: Oil with API gravity greater than 20°API but less than or equal to 25°API.
- Heavy Oil: Oil with API gravity between 10°API and 20°API inclusive and a viscosity greater than 100 cP.
- Natural Bitumen: Oil whose API gravity is less than 10° and whose viscosity is commonly greater than 10,000 cP. It is not possible to define natural bitumen on the basis of viscosity alone because much of it, defined on the basis of gravity, is less viscous than 10,000 cP. In addition, viscosity is highly temperature-

dependent (fig. 1), so that it must be known whether it is measured in the reservoir or in the stock tank. In dealing with Russian resources the term natural bitumen is taken to include both maltha and asphalt but excludes asphaltite.

- Total Original Oil in Place (TOOIP): Both discovered and prospective additional oil originally in place.
- Original Oil in Place-Discovered (OOIP-Disc.): Discovered original oil in place.
- Reserves (R): Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, and quantities of petroleum that are anticipated to be technically but not necessarily commercially recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian reserve classes A, B, and C1 are included here (See Grace, Caldwell, and Hether,1993, for an explanation of Russian definitions.)
- Prospective Additional Oil in Place: The amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study.
- Original Reserves (OR): Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimately recoverable, particularly in the case of new discoveries.

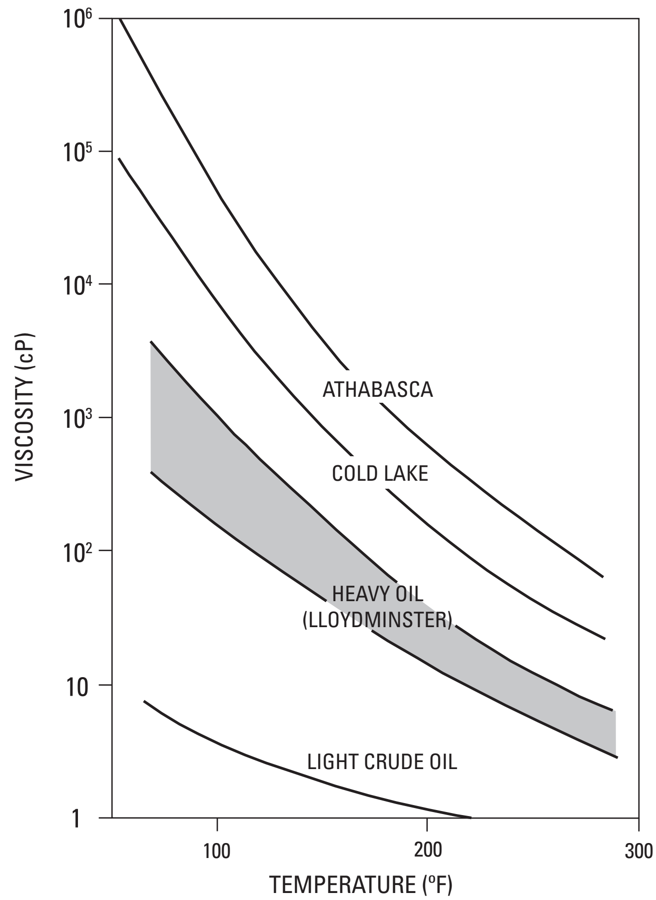

Figure 1. Response of viscosity to change in temperature for some Alberta oils (cP, centipoise), (Raicar and Proctor, 1984).

Chemical and Physical Properties

Fundamental differences exist between natural bitumen, heavy oil, medium oil, and conventional (light) oil, according to the volatilities of the constituent hydrocarbon fractions: paraffinic, naphthenic, and aromatic. When the light fractions are lost through natural processes after evolution from organic source materials, the oil becomes heavy, with a high proportion of asphaltic molecules, and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen. Therefore, heavy oil, regardless of source, always contains the heavy fractions, the asphaltics, which consist of resins, asphaltenes, and preasphaltenes (the carbene-carboids) (Yen, 1984). No known heavy oil fails to incorporate asphaltenes. The large asphaltic molecules define the increase or decrease in the density and viscosity of the oil. Removal or reduction of asphaltene or preasphaltene drastically affects the rheological properties of a given oil and its aromaticity (Yen, 1984). Asphaltenes are defined formally as the crude oil fraction that precipitates upon addition of an n-alkane, usually n-pentane or n-heptane, but remains soluble in toluene or benzene. In the crude oil classification scheme of Tissot and Welte (1978), the aromatic-asphaltics and aromatic-naphthenics characterize the heavy oil and natural bitumen deposits of Canada and Venezuela and are the most important of all crude oil classes with respect to quantity of resources. The aromatic-intermediate class characterizes the deposits of the Middle East (Yen, 1984).

Some of the average chemical and physical properties of conventional, medium, and heavy crude oils and natural bitumen are given in table 1, in order to show their distinguishing characteristics. The data are derived from multiple sources, some old and others adhering to standards employed in different countries. The conversion factors outlined in table 2 were used to convert published data to a uniform standard. Some of the properties in table 1 are important with respect to heavy oil and natural recovery from the ground and other properties in table 1 serve as the basis for decisions for upgrading and refinery technologies. Moving across table 1 from conventional oil to natural bitumen, increases may be seen in density (shown as reductions in API gravity), coke, asphalt, asphaltenes, asphaltenes + resins, residuum yield (percent volume), pour point, dynamic viscosity, and the content of copper, iron, nickel, vanadium among the metals and in nitrogen and sulfur among the non-metals. Values diminish for reservoir depth, gasoline and gas-oil yields, and volatile organic compounds (VOC and BTEX –Benzene, Toluene, Ethylbenzene, and

Xylenes). The significance of these differences is often reflected in the capital and operating expenses required for the recovery, transportation, product processing, and environmental mitigation of the four oil types. The principal sources of analytical data for table 1 are Environmental Technology Centre (2003), Hyden (1961), Oil & Gas Journal Guide to Export Crudes (2006), U.S. Department of Energy, National Energy Technology Laboratory (1995), and various analyses published in technical reports.

The resins and asphaltenes play an important role in the accumulation, recovery, processing, and utilization of petroleum. The resins and asphaltenes are the final form of naphtheno-aromatic molecules. The carbon skeleton appears to comprise three to five polyaromatic sheets, with some heterocyclic (N-S-O) compounds. These crystallites may combine to form high molecular weight aggregates, with the high viscosity of heavy oils related to the size and abundance of the aggregates. Most asphaltenes are generated from kerogen evolution in response to depth and temperature increases in sedimentary basins. Different types of asphaltenes may be derived from the main kerogen types. Asphaltenes are not preferentially mobilized, as are light hydrocarbons during migration from source rocks to reservoir beds, where they are less abundant if the crude oil is not degraded (Tissot, 1981).

Some heavy oil and natural bitumen originates with chemical and physical attributes shown in table 1 as immature oil which has undergone little if any secondary migration. The greatest amount of heavy oil and natural bitumen results from the bacterial degradation under aerobic conditions of originally light crude oils at depths of about 5,000 feet or less and temperatures below 176°F. The consequence of biodegradation is the loss of most of the low molecular weight volatile paraffins and naphthenes, resulting in a crude oil that is very dense, highly viscous, black or dark brown, and asphaltic. An active water supply is required to carry the bacteria, inorganic nutrients, and oxygen to the oil reservoir, and to remove toxic by-products, such as hydrogen sulfide, with low molecular weight hydrocarbons providing the food (Barker, 1979). The low molecular weight components also may be lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface (Barker, 1979). The importance of this process to the exploitation of heavy oil and natural bitumen lies in the increase of NSO (nitrogen-sulfur-oxygen) compounds in bacterially-altered crude oil and the increase in asphaltenes (Kallio, 1984).

Bacterial degradation of crude oil may also take place under anaerobic conditions, thus obviating the need for a fresh water supply at shallow depths (Head, Jones, and Larter, 2003; Larter and others, 2006). This proposal envisions degradation even of light oils at great depths so long as the maximum limiting temperature for bacterial survival is not exceeded. This theory does not account in any obvious way for the high percentage in heavy oil and natural bitumen of polar asphaltics, that is, the resins and asphaltenes.

Oil mass loss entailed in the formation of heavy oil and natural bitumen deposits has been the subject of numerous research studies. Beskrovnyi and others (1975) concluded that three to four times more petroleum was required than the reserves of a natural bitumen for a given deposit. Based upon material balance calculations in the Dead Sea basin, Tannenbaum, Starinsky, and Aizenshtat (1987) found indications that 75% of the original oil constituents in the C15+ range had been removed as a result of alteration processes. By accounting for the lower carbon numbers as well, they estimated that the surface asphalts represented residues of only 10-20% of the original oils. Head, Jones, and Larter (2003) diagram mass loss increasing from essentially zero for conventional oil to something more than 50% for heavy oils, which of themselves are subject to no more than 20% loss. Accompanying the mass loss is a decrease in API gravity from 36° to 5-20°; decrease in gas/oil ratio from 0.17 kg gas/kg oil; decrease in gas liquids from 20% to 2%; increase in sulfur from 0.3wt% to 1.5+wt%; and decrease in C15+ saturates from 75% to 35%. This calculation of mass loss shows: (1) the enormous amount of oil initially generated in heavy oil and natural bitumen basins, especially Western Canada Sedimentary and Eastern Venezuela basins; and (2) the huge economic burden imposed by this mass loss on the production-transportation-processing train of the remaining heavy oil and natural bitumen.

Origins of Heavy Oil and Natural Bitumen

It is possible to form heavy oil and natural bitumen by several processes. First, the oil may be expelled from its source rock as immature oil. There is general agreement that immature oils account for a small percentage of the heavy oil (Larter and others, 2006). Most heavy oil and natural bitumen is thought to be expelled from source rocks as light or medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation. In this case, the biodegradation is aerobic. A third proposal is that biodegradation can also occur at depth in subsurface reservoirs (Head, Jones, and Larter, 2003; Larter and others, 2003; Larter and others, 2006). This explanation permits biodegradation to occur in any reservoir that has a water leg and has not been heated to more than 176° F. The controls on the biodegradation depend on local factors rather than basin-wide factors. Because the purpose of this report is to describe the geologic basin setting of the known heavy oil and natural bitumen deposits, it is beyond the scope of this report to argue the source or genesis of heavy oil and natural bitumen for each basin of the world.

Data Sources

Data for heavy oil resource occurrences and quantities for individual oilfields and reservoirs have been compiled from many published reports and commercial data bases. The most important of these include Demaison (1977), IHS Energy Group (2004), NRG Associates (1997), Parsons (1973), Roadifer (1987), Rühl (1982), and the U.S. Department of Energy, National Energy Technology Laboratory (1983, 2005)

Data for natural bitumen deposits in the United States are summarized in U.S Department of Energy, National Energy Technology Laboratory (1991), but information for Utah is taken from Oblad and others (1987) and Ritzma (1979). Although there is no single data source for deposits outside the United States, there is a rich literature, particularly for Russia and the countries of the Former Soviet Union. For Canada, reliance is placed on reports of the Alberta Energy and Utilities Board (2004) and Saskatchewan Industry and Resources (2003).

Resource Estimates

We consider the total original oil in place (OOIP) to be the most useful parameter for describing the location and volume of heavy oil and natural bitumen resources. Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define the resource volumes that could someday be of commercial interest. If only a recoverable volume of heavy oil for the accumulation was published, the discovered OOIP was computed according to the protocol set forth in table 3.

Natural bitumen originally in place is often reported in the literature. Where only a recoverable estimate is published, the in-place volumes were calculated according to the protocols given for heavy oil; this is especially the case for bitumen deposits above 4°API gravity, to which we arbitrarily refer as extra-heavy oil.

Poorly known deposits of heavy oil and natural bitumen are included in the category of prospective additional resources, as described in table 3. In no case are values for prospective additional resource volumes calculated as in the case of discovered resources but were taken directly from the published literature.

Table 4 summarizes the resources and essential physical parameters of the heavy oil and natural bitumen contained in each of the basin types. These characteristics affect heavy oil and natural bitumen occurrence and recovery. Recovery can be primary, as in the case of cold production without gravel packing, if the gas to oil ratio is high enough to provide necessary reservoir energy. Otherwise, recovery generally necessitates the application of enhanced recovery methods, such as thermal energy or the injection of solvents.

Recovery Methods

How the reservoir parameters apply to enhanced recovery is summarized from Taber, Martin, and Seright (1997a, 1997b) in table 5, which covers the most commonly used, or at least attempted enhanced oil recovery (EOR) methods. Of these methods, immiscible gas injection, polymer flooding, and *in situ* combustion (fireflood) have met with limited success for heavy oil and natural bitumen. Steam injection (cyclic steam, huff 'n puff) has been most successful, frequently by use of cyclic steam, followed by steam flooding. Surface mining and cold *in situ* production are usually considered to be primary recovery methods. They can be suited to the extraction of heavy oil and natural bitumen under proper conditions.

Most of the process descriptions which follow are taken from Taber, Martin, and Seright (1997b). Many processes may result in the process agent, such as nitrogen or carbon dioxide, remaining immiscible with the reservoir hydrocarbon or else becoming miscible with it. The miscibility is dependent upon the minimum miscibility pressure (MMP) and determines the way in which the process agent achieves EOR. While this summary discussion shows the breadth of the EOR processes operators have tried and continue to try as experimental projects, thermal EOR methods account for most of the heavy oil that is commercially produced. Data on the frequency of the applications are taken, unless otherwise cited, from the Oil and Gas Journal Historical Review, 1980-2006 (2006), particularly the Oil and Gas Journal 2000 and 2006 EOR Surveys.

Nitrogen gas drive is low in cost and therefore may be used in large amounts. It is commonly used with light oils for miscible recovery. However, it may also be used for an immiscible gas flood. The Oil and Gas Journal 2000 Survey includes one immiscible nitrogen gas drive in a sandstone reservoir with 16˚API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. The Journal's 2006 Survey reports one each heavy oil nitrogen miscible and nitrogen immiscible projects. The miscible project is 19˚API, located in the Bay of Campeche, with 19 wells, but with no report of production capacity. The immiscible project has oil of 16˚API at 4,600 feet in sandstone. For this project total production is reported to be 1,500 b/d of which 1,000 b/d is enhanced by immiscible nitrogen injection.

Of the 77 CO2 projects in the Journal 2000 Survey, 70 are for miscible CO2 and none entails heavy oil. This is true also in the Journal 2006 Survey, where all 86 CO2 projects are devoted to light oil, above 28˚API. In the Journal 2000 Survey, five of the seven immiscible CO2 projects are applied to heavy oil reservoirs, four in clastics and one in limestone. The latter, in the West Raman field in Turkey, involves oil of 13°API, lies at 4,265 feet, and produces 8,000 b/d. The reservoir contains nearly two billion barrels of original oil in place. Recoverable reserves remain low because of the recalcitrance of the reservoir. Steam flooding has been unsuccessful. By the date of the Journal 2006, there are eight immiscible CO2 projects, with five of them entailing heavy oil amounting to 7,174 b/d. The two largest projects are light oil and heavy oil and are each in carbonate reservoirs.

Polymer/chemical flooding includes micellar/polymer, alkaline-surfactant-polymer (ASP), and alkaline fluids (Taber, Martin, and Seright, 1997a, 1997b). Recovery is complex, leading to the lowering of interfacial tension between oil and water, solubilization of oil in some micellar systems, emulsification of oil and water, wettability alteration, and enhancement of mobility. Limitations and costs indicate for these floods the desirability of clean clastic formations. The Journal 2000 Survey shows five heavy oil polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 feet. They were producing about 366 b/d and the projects were deemed successful or promising. Projects such as these are below the desirable gravity limits and are more viscous than desired at 45 cP.

Polymer floods improve recovery over untreated water flood by increasing the viscosity of the water, decreasing thus the mobility of the water, and contacting a larger volume of the reservoir. The advantages of a polymer flood over a plain water flood are apparent. The Journal 2000 Survey lists 22 polymer flood projects, of which five involve heavy oil. These five are within the range of the polymer screen, although the gravities are marginal, lying from 13.5°API to a bit above 15°API. The five were producing 7,140 b/d, of which 2,120 b/d were attributed to EOR. The Journal 2006 Survey shows 20 polymer floods, with five exploring heavy oil reservoirs. Three of the five are producing 7,140 b/d total oil and 2,120 b/d of enhanced production.

The Journal 2000 Survey shows four hot water floods, one of which is heavy oil with a gravity of 12°API, viscosity of 900 cP, and starting saturation of only 15 percent. Project production was 300 b/d. Two of three hot water floods included in the Journal 2006 Survey are intended to enhance production of heavy oil. The two yield about 1,700 b/d of total oil and 1,700 b/d of enhanced hot water flood oil.

In situ combustion (fire flood) is theoretically simple, setting the reservoir oil on fire and sustaining the burn by the injection of air. Usually, the air is introduced through an injector well and the combustion front moves toward to the production wells. A variant is to include a water flood with the fire, the result being forward combustion with a water flood. Another variant is to begin a fire flood, then convert the initial well to a producer and inject air from adjacent wells. The problem with this reverse combustion is that it doesn't appear to work.

In situ combustion leads to oil recovery by the introduction of heat from the burning front, which leads to reduction in viscosity. Further, the products of steam distillation and thermal cracking of the reservoir oil are carried forward to upgrade the remaining oil. An advantage of the process is that the coke formed by the heat itself burns to supply heat. Lastly, the injected air adds to the reservoir pressure. The burning of the coke sustains the process so that the process would not work with light oil deficient in asphaltic components. The process entails a number of problems, some severe, but the Journal 2000 Survey shows 14 combustion projects, of which five are light oil and the remaining nine are heavy, between 13.5°API and 19°API. Viscosities and starting oil saturations are relatively high. It is notable that the heavy oil projects are in sandstones and the light oil in carbonates. The heavy oil *in situ* combustion projects were producing about 7,000 b/d. The Journal 2006 Survey includes nine heavy oil combustion projects among a total of twenty-one. The heavy oil projects yield about 7,000 b/d of combustion-enhanced oil, which ranges from 13.5˚API to 19˚API.

Steam injection for EOR recovery is done in two ways, either by cyclic steam injection (huff 'n puff) or continuous steam flood. Projects are frequently begun as cyclic steam, whereby a high quality steam is injected and soaks the reservoir for a period, and the oil, with lowered viscosity from the heat, is then produced through the injection well. Such soak cycles may be repeated up to six times, following which a steam flood is initiated. In general, steam projects are best suited to clastic reservoirs at depths no greater than about 4,000 feet, and with reservoir thicknesses greater than 20 feet and oil saturations above 40% of pore volume. For reservoirs of greater depth the steam is lowered in quality through heat loss to the well bore to where the project becomes a hot water flood. Steam is seldom applied to carbonate reservoirs in large part due to heat loss in fractures.

The Journal 2000 Survey lists 172 steam drive projects. Of these, four in Canada give no gravity reading, thirteen are medium oil from 22°API to 25°API, and the rest are heavy oil. The largest of all is at Duri field in Indonesia and this oil is 22°API. For the project list as a whole, the average gravity is 14°API, with a maximum value of 30°API and a minimum of 4°API. The average viscosity is 37,500 cP, with maximum and minimum values of 5,000,000 cP and 6 cP. Oil saturations range from 35% to 90%, the average being 68%. Most importantly, production from the project areas was 1.4 million b/d and of this, 1.3 million b/d was from steam drive EOR.

All but three of the 120 steam projects found in the Journal 2006 Survey entail recovery of heavy oil. The oil averages 12.9˚API, with a low value of 8˚API and a high of 28˚API (one of the three light oil reservoirs). The viscosity averages 58,000 cP, with a high value of 5 million cP and a low of 2 cP. The projects are yielding over 1.3 million b/d, virtually all being steam EOR.

Maps

The geographic distribution of basins reporting heavy oil and natural bitumen, as identified by their Klemme basin types, appears on Plate 1. A diagram of the Klemme basin classification illustrates the architectural form and the geological basin structure by type. This plate also includes histograms of the total original oil in place resource volumes of both heavy oil and natural bitumen. Plates 2 and 3, respectively, depict the worldwide distribution of heavy oil and natural bitumen resources originally in place. Each map classifies basins by the reported volumes of total original oil in place. A table ranks the basins by total original oil in place volumes besides indicating Klemme basin type and reporting discovered original oil in place and prospective additional oil in place. Plates 2 and 3 also include an inset map of the geographic distribution of original heavy oil or natural bitumen by 10 world regions (see table 6 for regional listing of countries reporting heavy oil or natural bitumen.)

Basin outlines of the sedimentary provinces are digitally reproduced from the AAPG base map compiled by St. John (1996). The basin outlines of St. John (1996) are unaltered. However, the reader should note that the basin outlines are considered to be generalizations useful for displaying the resource distributions but are less than reliable as a regional mapping tool. Also, some basin names have been changed to names more commonly used by geologists in the local country. These equivalent names and the original names from Bally (1984) and St. John (1996) are detailed in table 1-1 in Appendix 1. The basin outline for Eastern Venezuela as shown does not include the island of Trinidad where both heavy oil and natural bitumen resources occur. For this report, resources from Trinidad and Tobago are reported in the Eastern Venezuela basin totals. In a few cases a single basin as outlined on the plates is composed of multiple basins to provide more meaningful local information. This is particularly true in the United States, where the AAPG-CSD map was employed (Meyer, Wallace, and Wagner, 1991). In each case, the individual basins retain the same basin type as the basin shown on the map and all such basins are identified in Appendix 1.

Basins having heavy oil or natural bitumen deposits are listed in table 2-1 in Appendix 2 along with the Klemme basin type, countries and U.S. states or Canadian provinces reporting deposits and other names cited in literature. The Klemme basin classification diagram in Plate 1 is reprinted in fig. 3-1 in Appendix 3 for the reader's convenience. The tables from Plates 2 and 3 are reprinted as table 4-1 and table 4-2 for the reader's convenience.

Klemme Basin Classification

Many classifications of petroleum basins have been prepared. In one of the earliest, Kay (1951) outlined the basic architecture of geosynclines, with suggestions as to their origins. Kay's work preceded the later theory of plate tectonics. Klemme (1977, 1980a, 1980b, 1983, 1984) gives a summary description of petroleum basins together with their classification, based upon basin origin and inherent geological characteristics. This classification is simple and readily applicable to the understanding of heavy oil and natural bitumen occurrence. The Klemme basin types assigned to the heavy oil and natural bitumen basins described in this report correspond to the assignments made in St. John, Bally, and Klemme (1984). In some cases of multiple type designations in St. John, Bally, and Klemme (1984) a unique type designation was resolved by reference to Bally (1984) or Bally and Snelson (1980). Only a few of the basins originally designated as multiple types in St. John, Bally and Klemme (1984) appear to contain heavy oil and natural bitumen.

Table 7 summarizes the criteria upon which Klemme based his classification. The general description of the resource endowment associated to the Klemme basin classification is based upon oilfield (and gasfield) data of the world as of 1980 without regard to the density or other chemical attributes of the hydrocarbons they contain (Klemme, 1984). At the time of Klemme's work, the average density U.S. refinery crude oil was about 33.7°API (Swain, 1991). A decline in the average to about 30.6°API by 2003 perhaps signifies the increasing importance of heavy oil in the mix (Swain, 2005).

Generally, basins may be described as large or small and linear or circular in shape. They may also be described by the ratio of surface area to sedimentary volume. The basement profile or basin cross-section, together with the physical description, permits the interpretation of the fundamental basin architecture. The basin can then be placed within the relevant plate tectonic framework and assigned to one of four basin types, of which two have sub-types. A diagram of the Klemme basin types appears on Plate 1, color-coded to the basins on the map.

In the following section we provide descriptions of the basin types from Klemme (1980b, 1983, 1984) followed by discussion of the heavy oil and natural bitumen occurrences within those same basin types, summary data for which are given in table 4. Because most heavy oil and natural bitumen deposits have resulted from the alteration of conventional and medium oil, the factors leading to the initial conventional and medium oil accumulations are relevant to the subsequent occurrence of heavy oil and natural bitumen.

Type I. Interior Craton Basins

The sediment load in these basins is somewhat more clastic than carbonate. Reservoir recoveries are low and few of the basins contain giant fields. Traps are generally related to central arches, such as the Cincinnati arch, treated here as a separate province (Plates 1-3), or the arches of the Siberian platform (see below for further explanation). Traps also are found in smaller basins over the craton, such as the Michigan basin. The origin of these depressions is unclear although most of them began during the Precambrian (Klemme, 1980a, 1980b).

The six Type I basins having heavy oil contain less than 3 billion barrels of oil in place and of this 93% occurs in the Illinois basin alone. Four Type I basins that contain natural bitumen have 60 billion barrels of natural bitumen in place, with nearly 99% in the Tunguska basin in eastern Siberia and the rest in the Illinois basin. The Tunguska basin covers most of the Siberian platform, around the borders of which are found cratonic margin basins of Type IIA. For convenience all the resource is assigned to the Tunguska basin. The prospective additional resource of 52 billion barrels is almost certainly an absolute minimum value for this potentially valuable but difficult to access area (Meyer and Freeman, 2006.)

Type II. Continental Multicyclic Basins

Type IIA. Craton margin (composite)

These basins, formed on continental cratonic margins, are generally linear, asymmetrical in profile, usually beginning as extensional platforms or sags and ending as compressional foredeeps. Therefore they are multicyclic basins featuring a high ratio of sediment volume to surface area. Traps are mainly large arches or block uplifts and may be found in rocks of either the lower (platform) or upper (compression) tectonic cycle. About 14% of conventional oil discovered in the world by 1980 is from marginal cratonic basins (Klemme, 1980a, 1980b).

Type IIA basins are of moderate importance with respect to heavy oil, with about 158 billion barrels of oil in place distributed among 28 basins. Three Type IIA basins, the Western Canada Sedimentary, Putumayo, and Volga-Ural, have combined total heavy oil resource of 123 billion barrels of oil in place, or 78% of the total for Type IIA basins.

In comparison, natural bitumen in 24 Type IIA basins accounts for 2,623 billion barrels of natural bitumen in place, or nearly 48% of the world natural bitumen total. The Western Canada Sedimentary basin accounts for 2,334 billion barrels of natural bitumen in place, or about 89%. Of the Canadian total, 703 billion barrels of natural bitumen in place is prospective additional oil, largely confined to the deeply buried bitumen in the carbonate that underlie the Peace River and part of the Athabasca oil sand deposit in an area known as the Carbonate Triangle. The significance of the Canadian deposits lies in their concentration in a few major deposits: Athabasca, from which the reservoir is exploited at or near the surface and shallow subsurface, and Cold Lake and Peace River, from which the bitumen is extracted from the subsurface. Two other basins contain much less but still significant amounts of natural bitumen, the Volga-Ural basin in Russia (263 billion barrels of natural bitumen in place) and the Uinta basin in the United States (12 billion barrels of natural bitumen in place). The Volga-Ural deposits are numerous, but individually are small and mostly of local interest. The Uinta deposits are much more concentrated aerially, but are found in difficult terrain remote from established transportation and refining facilities.

Type IIB. Craton accreted margin (complex)

These basins are complex continental sags on the accreted margins of cratons. Architecturally, they are similar to Type IIA basins, but begin with rifting rather than sags. About three-quarters of Type IIA and IIB basins have proven productive, and they contain approximately one-fourth of the world's total oil and gas (Klemme, 1980a, 1980b).

The 13 Type IIB basins contain a moderate amount of heavy oil (193 billion barrels of oil in place). The two most significant basins are in Russia, West Siberia and Timan-Pechora. These, together with most of the other Type IIB heavy oil basins, are of far greater importance for their conventional and medium oil resources.

Five Type IIB basins hold 29 billion barrels of natural bitumen in place. Only the Timan-Pechora basin contains significant natural bitumen deposits, about 22 billion barrels of natural bitumen in place. Unfortunately, this resource is distributed among a large number of generally small deposits.

Type IIC. Crustal collision zone (convergent plate margin)

These basins are found at the crustal collision zone along convergent plate margins, where they are downwarped into small ocean basins. Although they are compressional in final form, as elongate and asymmetrical foredeeps, they begin as sags or platforms early in the tectonic cycle. Type IIC downwarp basins encompass only about 18 percent of world basin area, but contain nearly one-half of the world's total oil and gas. These basins are subdivided into three subtypes, depending on their ultimate deformation or lack thereof: Type IICa, closed; Type IICb, trough; and Type IICc, open (Klemme, 1980a, 1980b).

Although basins of this type begin as downwarps that opened into small ocean basins (Type IICc), they may become closed (Type IICa) as a result of the collision of continental plates. Upon closing, a large, linear, asymmetric basin with sources from two sides is formed, resembling a Type IIA basin. Further plate movement appears to destroy much of the closed basin, leaving a narrow, sinuous foredeep, that is, a Type IICb trough. Relatively high hydrocarbon endowments in the open and the closed types may be related to above-normal geothermal gradients, which accentuates hydrocarbon maturation and long-distance ramp migration. Traps are mostly anticlinal, either draping over arches or compressional folds, and are commonly related to salt flowage.

Type IICa basins, with their architectural similarity to Type IIA basins, are the most important of the three Type IIC heavy oil basins. The 15 basins account for 1,610 billion barrels of the heavy oil in place, with the Arabian, Eastern Venezuela, and Zagros basins containing 95% of the total. Of particular interest is the Eastern Venezuela basin which includes large accumulations of conventional and medium oil, while at the same time possessing an immense resource of both heavy oil and natural bitumen.

Type IICa basins also are rich in natural bitumen, with a total of 2,507 billion barrels of natural bitumen in place among the six. About 83% of this occurs in Venezuela, mostly in the southern part of the Eastern Venezuelan basin known as the Orinoco Oil Belt. Here the reservoir rocks impinge upon the

Guyana craton in much the same fashion as the reservoir rocks of the Western Canada Sedimentary basin lap onto the Canadian shield. The only other significant Type IICa accumulation of natural bitumen is found in the North Caspian basin (421 billion barrels of natural bitumen in place).

Fourteen Type IICb basins contain modest amounts of heavy oil (32 billion barrels of oil in place) and even less of natural bitumen (5 billion barrels of natural bitumen in place in seven basins). Much of this resource is found in the Caltanisetta and Durres basins, on either side of the Adriatic Sea. Durres basin resources are aggregated with the South Adriatic and the province is labeled South Adriatic on the plates. Significant amounts of the Caltanisetta resource occurs offshore.

The amount of heavy oil in the 12 Type IICc basins is substantial (460 billion barrels of oil in place). The Campeche, by far the largest, and Tampico basins in Mexico and the North Slope basin in the United States account for 89% of the heavy oil. The Campeche field, which is actually an assemblage of closely associated fields, is found about 65 miles offshore of the Yucatan Peninsula in the Gulf of Mexico. The North Slope basin, on the north coast of Alaska, occurs in an area of harsh climate and permafrost, which makes heavy oil and natural bitumen recovery by the application of thermal (steam) methods difficult both physically and environmentally. The U.S. fields in the East Texas, Gulf Coast, and Mississippi Salt Dome basins account for only 5% of the heavy oil in basins of this type.

Only a small amount of natural bitumen (24 billion barrels) has been discovered in eight Type IICc basins. Two of these, the North Slope and South Texas Salt Dome basins, are significant for possible future development.

Type III. Continental Rifted Basins

Type IIIA. Craton and accreted zone (rift)

These are small, linear continental basins, irregular in profile, which formed by rifting and simultaneous sagging in the craton and along the accreted continental margin. About two-thirds of them are formed along the trend of older deformation belts and one-third are developed upon Precambrian shields. Rifts are extensional and lead to block movements so that traps are typically combinations. Oil migration was often lateral, over short distances. Rift basins are few, about five percent of the world's basins, but half of them are productive. Because of their high recovery factors, Type IIIA basins accounted for 10% of the world's total recoverable oil and gas in 1980 (Klemme, 1980a, 1980b).

Globally, there are 28 Type IIIA heavy oil basins, containing 222 billion barrels of oil in place The Bohai Gulf basin in China accounts for 63% of the heavy oil, with an additional 11% derived from the Gulf of Suez and 10% from the Northern North Sea. Outside of these, most Type IIIA basins contain just a few deposits. The five basins in Type IIIA have almost 22 billion barrels of natural bitumen in place, but half of that is located in the Northern North Sea basin.

Type IIIB. Rifted convergent margin (oceanic consumption)

Type IIIBa basins are classified as back-arc basins on the convergent cratonic side of volcanic arcs. They are small, linear basins with irregular profiles (Klemme, 1980a, 1980b).

Not unlike Type IIIA basins, the volume of heavy oil found in the Type IIIBa basins is small. Seventeen heavy oil basins contain 49 billion barrels of oil in place and 83% of this amount is in Central Sumatra.

Just 4 billion barrels of natural bitumen in place are identified in the Type IIIA basin called Bone Gulf. Small amounts are also known to occur in the Cook Inlet and Tonga basins.

Type IIIBb basins are associated with rifted, convergent cratonic margins where wrench faulting and subduction have destroyed the island arc. They are small, linear, and irregular in profile.

The 14 Type IIIBb basins containing heavy oil account for only 134 billion barrels of oil in place. These basins are only moderately important on a global scale, but have been very important to the California oil industry. The seven such basins of California - Central Coastal, Channel Islands, Los Angeles, Sacramento, San Joaquin, Santa Maria, and Ventura – equal 129 billion barrels of oil in place or 96%.

There are nine Type IIIBb basins that report natural bitumen deposits. They contain 4 billion barrels of natural bitumen in place, about half of which is in the Santa Maria basin.

Types IIIBa and IIIBb basins comprise about seven percent of world basin area, but only one-quarter of the basins are productive for oil of all types. However, the productive ones, which represent only two percent of world basin area, yield about seven percent of total world's oil and gas (Klemme, 1983). Some of these productive basins, particularly those located in California, have high reservoir recovery factors.

Type IIIBc basins are small and elongate, irregular in profile, and occupy a median zone either between an oceanic subduction zone and the craton or in the collision zone between two cratonic plates. They result from median zone wrench faulting and consequent rifts. Such basins make up about three and one-half percent of world basin area and contribute two and one-half percent of total world oil and gas.

Type IIIBc basins are important to the occurrence of heavy oil (351 billion barrels of oil in place). Although there are nine basins of this type, 92% of the heavy oil is concentrated in the Maracaibo basin. The Maracaibo basin also yields 95% of the 178 billion barrels of natural bitumen in place in the five basins containing this type of oil. This makes the Maracaibo basin unique: no other basin type is so completely dominated by a single basin.

Type IIIC. Rifted passive margin (divergence)

These basins, often aptly called pull-apart basins, are extensional, elongate, and asymmetric. Located along major oceanic boundaries of spreading plates, they are divergent and occupy the intermediate zone between thick continental crust and thin oceanic crust. They appear to begin with a rifting stage, making possible the later sedimentary fill from the continent. Type IIIC basins, comprising 18 percent of the world's basin area, are mostly offshore and are often in water as deep as 5,000 feet. For this reason their development has been slow but is accelerating as traditional, easily accessible basins reach full development and world demand for petroleum increases (Klemme, 1980a, 1980b).

Twenty-eight Type IIIC basins yield 158 billion barrels of heavy oil in place, but one, the offshore Campos basin, contains 66% of this heavy oil. These continental margin basins must at some point in their histories have been sufficiently elevated to permit their generated conventional oil to be degraded. It is possible that the heavy oil could be very immature, having undergone only primary migration and later elevation. The geologic history of such basins does not encourage this view. However, the oil could well have been degraded bacterially at depth according to the recently proposed mechanisms suggested by Head, Jones, and Larter (2003) and Larter and others (2006). In a pull-apart basin the sediments would have accumulated rapidly and at depth, the expressed oil then was subject to degradation. The problem with degradation at depth is the loss of mobility unless it can be demonstrated that the oil was never elevated and, in fact, the Campos basin oil is deep, occurring at an average depth of nearly 8,400 feet.

The bitumen resource in Type IIIC basins is small (47 billion barrels of natural bitumen in place in seven basins), as are nearly all bitumen occurrences in comparison with the Western Canada Sedimentary and Eastern Venezuela basins. But the 38.3 billion barrels of natural bitumen in place in the Ghana basin of southwestern Nigeria is exploitable and the amount of the resource may be understated. Like many bitumen deposits it awaits more detailed evaluation.

Type IV. Delta (Tertiary to recent)

Deltas form along continental margins as extensional sags, are circular to elongate, and show an extremely high ratio of sediment fill to surface area. Architecturally, they are modified sags comprised of sediment depocenters and occur along both divergent and convergent cratonic margins. Although by 1980 delta basins provide two and one-half percent of world basin area and perhaps six percent of total oil and gas (Klemme, 1980a, 1980b), they account for more of the conventional resource endowment with the recent successful exploration in frontier deep water areas.

The three Type IV delta basins produce scant heavy oil (37 billion barrels of oil in place) and no natural bitumen. This is related to the extremely high ratio of sediment fill to surface area and that these basins exhibited rapid burial of the source organic matter. Burial is constant and uninterrupted, providing very limited opportunity for degradation of the generated petroleum.

Type V. Fore-Arc Basins

Fore-arc basins are located on the ocean side of volcanic arcs. They result from both extension and compression, are elongate and asymmetrical in profile, and architecturally are the result of subduction. Fore-arc basins are few in number and generally not very productive (Klemme, 1980a, 1980b).

Very small amounts of heavy oil are found in the Barbados basin. Although a natural bitumen deposit is reported in the Shumagin basin, volume estimates are not available.

Essentially no heavy oil or natural bitumen is found in fore-arc basins because these basins do not generate large quantities of petroleum of any type and therefore provide relatively little material to be degraded.

Regional Distribution of Heavy Oil and Natural Bitumen

The preceding discussion has been concerned with the distribution of heavy oil and natural bitumen in the world's geological basins. This is of paramount interest in the exploration for the two commodities and for their exploitation. The chemical and physical attributes of the fluids and the reservoirs which contain them do not respect political boundaries.

At the same time it is necessary to understand the geography of the heavy oil and natural bitumen for both economic and political reasons. These factors will be dealt with in detail in a subsequent report. The bar graphs on Plates 2 and 3 give the regional distribution of total and discovered original oil in-place for heavy oil and natural bitumen, respectively. The distribution of the resources is given in table 8. The western hemisphere accounts for about 52 percent of the world's heavy oil and more than 85 percent of its natural bitumen. The Middle East and South America have the largest in-place volumes of heavy oil, followed by North America. North and South America have, by far, the largest in-place volumes of natural bitumen. Very large resource deposits are also known in eastern Siberia but insufficient data are available to make more than nominal size estimates.

Summary

From the preceding basin discussion, Klemme basin Type IICa is by far the most prolific in terms of heavy oil. For natural bitumen Klemme basin Type IIA and Type IICa are the most prolific. The basin types involved are architecturally analogous, beginning with depositional platforms or sags and ending up as foredeeps. They differ only in their modes of origin. What they have in common is truncation against cratonic masses updip from rich source areas. This situation permitted immense accumulations of conventional oil at shallow depths, with near ideal conditions for oil entrapment and biodegradation resulting in formation of heavy oil and bitumen accumulations. The prospective resources from the prospective additional resource deposits in these basins are larger than the discovered resources of many basin types.

The Klemme basin classification system includes elements of basin development and architecture that control basin type. The observed pattern of the heavy oil and natural bitumen occurrences across basin types is consistent with the formation of heavy oil and natural bitumen through the process of degradation of conventional oil. Only relatively small quantities of heavy oil were found in the Interior Craton (Type I), Deltas (Type IV) and Fore-Arc basins (Type V).

Type IICa basins, including the Arabian, Eastern Venezuela, and Zagros, have the largest endowments of heavy oil and also contain the largest amounts of conventional oil. Large volumes of heavy oil are also found in both Type IICc basins, notably, the Campeche, Tampico, and North Slope basins, and in Type IIIBc basins, primarily Maracaibo basin. For natural bitumen, the Western Canada Sedimentary and Eastern Venezuela basins have similar development histories and basin architectural features. Some basin development patterns promote the formation of greater volumes of heavy oil and natural bitumen than others. This is seen most clearly in present occurrences of heavy oil and natural bitumen in the Type IICa and Type IICc basins, with their rich source areas for oil generation and up-dip migration paths to entrapment against cratons. Conventional oil may easily migrate through the tilted platforms until the platforms are breached at or near surface permitting deveopment of asphaltic seals.

Acknowledgments

We gratefully acknowledge critical reviews of the manuscript by James Coleman and Robert Milici, U.S. Geological Survey, and Dale Leckie and Geoff Ryder, Nexen Inc. We are in debt to Dorothy B. Vitaliano and Nora Tamberg, U.S. Geological Survey, Retired, for translations of Russian literature into English.

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Tables 1–8

Table 1. Some chemical and physical attributes of crude oils (averages).

[cP, centipoise; wt%, weight percent; mgKOH/g, milligrams of potassium hydroxide per gram of sample; sp gr, specific gravity; vol%, volume percent; ppm, parts per million; Concarbon, Conradson carbon; VOC, volatile organic compounds; BTEX, benzene, toluene, ethylbenzene, and xylenes]

Attribute	Unit	Conventional oil (131 basins, 8148 deposits)	Medium oil (74 basins, 774 deposits)	Heavy oil (127 basins, 1199 deposits)	Natural bitumen (50 basins, 305 deposits)
API gravity	degrees	38.1	22.4	16.3	5.4
Depth	feet	5,139.60	3,280.20	3,250.00	1,223.80
Viscosity (77°F)	cP	13.7	34	100,947.00	1,290,254.10
Viscosity (100°F)	cP	10.1	64.6	641.7	198,061.40
Viscosity (130°F)	cP	15.7	34.8	278.3	2,371.60
Conradson Carbon	wt%	1.8	5.2	8	13.7
Coke	wt%	2.9	8.2	13	23.7
Asphalt	wt%	8.9	25.1	38.8	67
Carbon	wt%	85.3	83.2	85.1	82.1
Hydrogen	wt%	12.1	11.7	11.4	10.3
Nitrogen	wt%	0.1	0.2	0.4	0.6
Oxygen	wt%	1.2		1.6	2.5
Sulfur	wt%	0.4	1.6	2.9	4.4
Reid vapor pressure	psi	5.2	2.6	2.2	
Flash point	°F	17	20.1	70.5	
Acid number	mgKOH/g	0.4	1.2	2	3
Pour point	°F	16.3	8.6	19.7	72.9
C1-C4	vol%	2.8	0.8	0.6	
Gasoline + naphtha	vol%	31.5	11.1	6.8	4.4
Gasoline + naphtha	sp gr	0.76	0.769	0.773	0.798
Residuum	vol%	22.1	39.8	52.8	62.2
Residuum	sp gr	0.944	1.005	1.104	1.079
Asphaltenes	wt%	2.5	6.5	12.7	26.1
Asphaltenes + resins	wt%	10.9	28.5	35.6	49.2
Aluminum	ppm	1.174	1.906	236.021	21,040.03
Copper	ppm	0.439	0.569	3.965	44.884
Iron	ppm	6.443	16.588	371.05	4,292.96
Mercury	ppm	19.312	15	8.74	0.019
Nickel	ppm	8.023	32.912	59.106	89.137
Lead	ppm	0.933	1.548	1.159	4.758
Titanium	ppm	0.289	0.465	8.025	493.129
Vanadium	ppm	16.214	98.433	177.365	334.428
Residue Concarbon	wt%	6.5	11.2	14	19
Residue Nitrogen	wt%	0.174	0.304	0.968	0.75
Residue Nickel	ppm	25.7	43.8	104.3	
Residue Sulfur	ppm	1.5	3.2	3.9	
Residue Vanadium	ppm	43.2	173.7	528.9	532
Residue viscosity (122°F)	cP	1,435.80	4,564.30	23,139.80	
Total BTEX volatiles	ppm	10,011.40	5,014.40	2,708.00	
Total VOC volatiles	ppm	15,996.30	8,209.20	4,891.10	

Table 2. Conversion factors and equivalences applied to standardize data.

Standard unit in this report	Units as reported in literaure	Formula
	API gravity	
°API (degrees)	specific gravity (sp gr), (g/cm^3)	= (141.5/(sp gr))-131.5
	Area	
acre	square mile (mi^2)	= (1/640) mi^2
	square kilometer (km^2)	= 0.00405 km^2
	hectare (ha)	= 0.405 ha
	Asphalt in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 4.9× (CCR)
	Barrels of oil	
barrel (bbl), (petroleum, 1 barrel=42 gal)	cubic meter (m^3)	= 0.159 m^3
	metric tonne (t)	= 0.159× (sp gr) ×t
	Coke in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 1.6× (CCR)
	Gas-oil ratio	
cubic feet gas/barrel oil (ft^3 gas/bbl oil)	cubic meters gas/cubic meter oil (m^3 gas/m^3 oil)	= 0.18× (m^3gas/m^3oil)
	Parts per million	
parts per million (ppm)	gram/metric tonne (g/t)	= g/t
	milligram/kilogram (mg/kg)	= mg/kg
	microgram/gram (µg/g)	= µg/g
	milligram/gram (mg/g)	= 0.001 mg/g
	weight percent (wt%)	= 0.0001 wt%
	Parts per billion	
parts per billion (ppb)	parts per million (ppm)	= 0.001 ppm
	Permeability	
millidarcy (md)	micrometer squared (μm^2)	= 1,000 μm^2
	Pressure	
pound per square inch (psi)	kilopascal (kPa)	= 6.89 kPA
	megapascal (Mpa)	= 0.00689 MPa
	bar	= 0.0689 bar
	kilograms/square centimeter (kg/cm^2)	= 0.0703 kg/cm^2
	Specific gravity (density)	
specific gravity (sp gr), (g/cm^3)	°API (degrees)	= 141.5/(131.5+°API)
	Temperature	
degrees Fahrenheit (°F)	degrees Celsius (°C)	= (1.8×°C)+32
degrees Celsius (°C)	degrees Fahrenheit (°F)	= 0.556×(°F-32)
	Viscosity (absolute or dynamic)	
centipoise (cP)	Pascal second (Pa·s)	= 0.001 Pa·s
	millipascal second (mPa·s)	= mPa·s

Table 2. Conversion factors and equivalences applied to standardize data.—Continued

Standard unit in this report	Units as reported in literaure	Formula
	Viscosity (absolute or dynamic)—Continued	
centipoise (cP)—cont.	kinematic viscosity[1]: centistroke (cSt), (mm^2/sec)	= cSt × (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given density	= (SUS /4.632)× (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given °API	= (SUS /4.632)×(141.5/(131.5+°API))
	Weight percent	
weight percent (wt%)	parts per million (ppm)	= 10,000 ppm

[1] Kinematic viscosity is equal to the dynamic viscosity divided by the density of the fluid, so at 10°API the magnitudes of the two viscosities are equal.

Table 3. Total original in place resource calculation protocol when discovered oil in place is unavailable.

Define—

- OOIP-disc.: Original Oil In Place, discovered
- RF: Recovery factor (%)
- R: Reserves, known
- OR: Reserves, original sometimes called, known recovery, ultimate production if so reported
- AP: Production, annual
- CP: Production, cumulative
- PA: Prospective additional oil in place resource
- TOOIP = Total original oil in place

Calculations are based given data, which always receives priority; CP, AP and PA are never calculated and must be from published sources. (Assume CP, AP, PA are given)—

- R = 20×AP. This assumes a 20-year life or production plan for the viscous oil.
- OR = R+CP
- RF = 0.1 for clastic reservoirs or if no lithology is reported
- RF = 0.05 for carbonate reservoirs
- OOIP-disc. = OR/RF
- TOOIP = OOIP-disc. + PA

Table 4. Heavy oil and natural bitumen resources in billions of barrels of oil (BBO) and average characteristics of heavy oil and natural bitumen by basin type. Average values for gravity, viscosity, depth, thickness permeability are weighted by volume of oil in place discovered in each heavy oil or natural bitumen deposit by basin type; except for API gravity of heavy oil Type I, where because of relatively few deposits and several outlier values, a trimmed weighted mean value is shown.

[Volumes may not add to totals due to independent rounding; BBO, billions of barrels of oil; cP, centipoise]

Basin type	Total original oil in place (BBO)	Discovered oil in place (BBO)	API gravity (degrees)	Viscosity (cP @ 100°F)	Depth (feet)	Thickness (feet)	Porosity (percent)	Permeability (millidarcy)	Temperature (°F)
				Heavy oil					
I……….	3	2	15.9	724	1,455	11	15.3	88	122
IIA…….	158	157	16.3	321	4,696	36	22.8	819	102
IIB…….	181	181	17.7	303	3,335	96	27.2	341	82
IICa…...	1,610	1,582	15.5	344	3,286	150	24	242	144
IICb…...	32	32	15.4	318	3,976	161	16.9	2,384	126
IICc…...	460	460	17.8	455	6,472	379	19.6	1,080	159
IIIA……	222	222	16.3	694	4,967	279	24.9	1,316	159
IIIBa…..	49	49	19.2	137	558	838	24.9	2,391	122
IIIBb…..	134	134	15.8	513	2,855	390	31.9	1,180	116
IIIBc…..	351	351	13.5	2,318	4,852	142	20.1	446	145
IIIC……	158	158	17.2	962	7,227	273	25.1	868	159
IV……..	37	37	17.9	-	7,263	1,195	27.9	1,996	155
V………	<1	<1	18	-	1,843	135	30	-	144
All types	3,396	3,366	16	641	4,213	205	23.7	621	134
				Natural bitumen					
I……….	60	8		-	20	317	5.5	100	
IIA…….	2,623	1,908	6.8	185,407	223	53	0.4	611	173
IIB…….	29	26	4.5	-		209	13.1	57	113
IICa…...	2,509	2,319	4.4	31,789	806	156	29.8	973	174
IICb…...	5	5	6.8	-	8,414	1,145	4.7	570	181
IICc…...	24	23	5	1,324	3,880	82	32.4	302	263
IIIA……	22	22	8.7	-	4,667	882	30.3	1,373	85
IIIBa…..	4	4	-	-	-	-	-	-	-
IIIBb…..	3	3	6.7	500,659	3,097	586	28.6	2,211	89
IIIBc…..	178	178	9.5	1,322	8,751	52	34	751	139
IIIC……	47	14	7.3	-	900	103	23.1	2,566	117
IV……..	0	0							
V………	0	0							
All types	5,505	4,512	4.9	198,061	1,345	110	17.3	952	158

Table 5. Enhanced oil recovery (EOR) methods for heavy oil showing primary reservoir threshold criteria.

[modified from Taber, Martin, and Seright (1997a,b); cP, centipoises; PV, pore volume; ft, feet; md, millidarcy; °F, degrees Fahrenheit, wt%, weight percent]

Method	Gravity (°API)	Viscosity (cP)	Oil composition	Oil saturation (%PV)	Lithology	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
				Immiscible gases					
Immiscible gases[a]	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1,800	Not critical
				Enhanced waterflood					
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10[b]	<9,000	>200-140
				Thermal/mechanical					
Combustion	>10	<5,000	Asphaltic components	>50	Highly porous sandstone	>10	>50[c]	<11,500	>100
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200[d]	<4500	Not critical
Surface mining	>7	0 cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10[e]	Not critical	>3:1 overburden: sand ratio	Not critical

[a] Includes immiscible carbon dioxide flood.

[b] >3 md for some carbonate reservoirs if the intent is to sweep only the fracture systems.

[c] Transmissibility > 20md-ft/cP.

[d] Transmissibility > 50md-ft/cP.

[e] See depth.

Table 6. Listing of countries reporting deposits of heavy oil and/or natural bitumen grouped by region. (See inset maps of regional distribution on Plates 2 and 3.)

North America	South America	Europe	Africa	Transcaucasia	Middle East	Russia	South Asia	East Asia	Southeast Asia and Oceania
Canada	Argentina	Albania	Algeria	Azerbaijan	Bahrain	Russia	Bangladesh	China	Australia
Mexico	Barbados	Austria	Angola	Georgia	Iran		India	Japan	Brunei
United States	Bolivia	Belarus	Cameroon	Kazakhstan	Iraq		Pakistan	Taiwan	Indonesia
	Brazil	Bosnia	Chad	Kyrgyzstan	Israel				Malaysia
	Colombia	Bulgaria	Congo (Brazzaville)	Tajikistan	Jordan				Myanmar
	Cuba	Croatia	Democratic Republic of Congo (Kinshasa)	Turkmenistan	Kuwait				Philippines
	Ecuador	Czech Republic	Egypt	Uzbekistan	Neutral Zone				Thailand
	Guatemala	France	Equatorial Guinea		Oman				Tonga
	Peru	Germany	Gabon		Qatar				Vietnam
	Suriname	Greece	Ghana		Saudi Arabia				
	Trinidad & Tobago	Hungary	Libya		Syria				
	Venezuela	Ireland	Madagascar		Turkey				
		Italy	Morocco		Yemen				
		Malta	Nigeria						
		Moldova	Senegal						
		Netherlands	South Africa						
		Norway	Sudan						
		Poland	Tunsia						
		Romania							
		Serbia							
		Slovakia							
		Spain							
		Sweden							
		Switzerland							
		Ukraine							
		United Kingdom							

Table 7. Attributes of Klemme basin types.

[Sources for attributes 1-15 are Klemme (1980a, 1980b, 1984) and attributes 16 and 17 are from this report]

	Type I	Type IIA	Type IIB	Type IICa
	Craton interior	**Continental multicycle basins, craton margin**	**Continental multicycle basins: craton/acreted zone rift-faulted**	**Continental interior multicycle basins: close collision zone at paleoplate margin**
1. Crustal zone	Continental craton	Continental craton	Contnental craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone
2. Tectonic setting	Continenal crust within interior of craton, near or upon Precambrian sheld areas	Continental crust on exterior margin of craton, basins become multicylic ion Paleozoic or Mesozoic when a second cycle of sediments derived from uplife encroaches	Continental crust, or on margin of craton	Convergent margin along collision zone of paleoplates
3. Regional stress	Extensional	1st cycle: extension, 2nd cycle: compression	(1st) extension with rifting, (2nd) extensional sag	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep
4. Basin size, shape	Large, circular to elongate	Moderate to large, circular to elongate	Large, circular	Large, elongate
5. Basin profile	Symmetrical	Asymmetrical	Irregular to asymmetrical	Asymmetrical
6. Sediment ratio[1]	Low	High	High	High
7. Architectural sequence	Sag	1st cycle: platform or sag, 2nd cycle: foredeep	(1st) rift, (2nd) large circular sag	(1st) platform or sag, (2nd) foredeep
8. Special features	Unconformities, regional arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs
9. Basin lithology[2]	Clastic 60%, carbonate 40%	Clastic 75%, carbonate 25%	Clastic 75%, carbonate 25%	Clastic 35%, carbonate 65%
10. Depth of production[3]	Shallow	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 45%, moderate 30%, deep 25%
11. Geothermal gradient	Low	Low	High	High
12. Temperature	Cool	Cool	Cool	High
13. Age	Paleozoic	Paleozoic, Mesozoic	Paleozoic, Mesozoic	Upper Paleozoic, Mesozoic, Tertiary
14. Oil and gas recovery[4]	Low, few giant fields	Average	Generally average	High
15. Traps	Associated with central arches and stratigraphic traps along basin margins	Basement uplifts, mostly arches or blocks	Basement uplifts, mostly combination of structural stratigraphic	Basement uplifts, arches and fault blocks
16. Propensity for heavy oil	Low	Low	Low	High
17. Propensity for natural bitumen	Low	High	Low	High

[1]Sediment ratio: ratio of sediment volume to basin surface area.

[2]Basin lithology: percentages apply to reservoir rocks, not to the basin fill.

[3]Depth of production: shallow, 0-6000 ft.; medium, 6000-9000 ft.; deep, >9000 ft.

[4]Oil and gas recovery (barrels of oil equivalent per cubic mile of sediment): low, <60,000; average, >=60,000 but <300,000; high, >=300,000.

[5]Does not add to 100% in source, Klemme (1980a,b).

Table 7. Attributes of Klemme basin types.—Continued

	Type IICb	Type IICc	Type IIIA	Type IIIBa
	Continental interior multicycle basins: foredeep portion of collision zone at paleoplate margin	**Continental interior multicycle basins: open collision zone at paleoplate margin**	**Continental rifted basins: craton/accreted zone, rift-faulted, with small linear sag**	**Continental rifted basins: back arc rift-faulted convergent margin**
1. Crustal zone	Ocean crust early stages then continental crust of craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone	Continental craton and accreted zone	Contintental accreted zone with oceanic crust in early stages
2. Tectonic setting	Convergent margin along collision zone of paleoplates, but retain only proximal or foredeep portion of original sediment suite	Convergent margin along collision zone of paleoplates	Continental, on margin of craton. About two-thirds of Type IIIA basins form along trend of older deformation; remainder on Precambrian shields	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages
3. Regional stress	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) extension with local wrench faulting during rifting, (2nd) sag	(1st) extension with local wrench faulting compression, (2nd) extension and compression
4. Basin size, shape	Large, elongate	Large, elongate	Small to moderate, fault controlled, elongate	Small, elongate
5. Basin profile	Asymmetrical	Asymmetrical	Irregular	Irregular
6. Sediment ratio[1]	High	High	High	High but variable
7. Architectural sequence	(1st) platform or sag, (2nd) foredeep	(1st) platform or sag, (2nd) foredeep	(1st) extension with local wrench faulting druing rifting, (2nd) sag	Rift faulting leading to linear sag, may be followd by wrench faulting
8. Special features	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs, unconformities	Large traps, evaporite caps, unconformities, regional source seal	Large traps, and unconformities
9. Basin lithology[2]	Clastic 50%, carbonate 50%	Clastic 35%, carbonate 65%	Clastic 60%, carbonate 40%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 45%, moderate 30%, deep 25%	Shallow 45%, moderate 30%, deep 25%	Moderate 55%, shallow 30%, deep 15%	Shallow 70%, moderate 20%, deep 10%
11. Geothermal gradient	High	High	High	High
12. Temperature	High	High	Normal to high	Normal to high
13. Age	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Paleogene, Neogene	Upper Mesozoic, Paleogene and Neogene
14. Oil and gas recovery[4]	Generally low	High	Generally high	Variable
15. Traps	Basement uplifts, arches and fault blocks	Basement uplifts, arches and fault blocks	Basement uplifts, combination structural/stratigraphic; result in fault block movement	Basement uplifts, fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Moderate	Low
17. Propensity for natural bitumen	Low	Low	Low	Low

Table 7. Attributes of Klemme basin types.—Continued

	Type IIIBb	Type IIIBc	Type IIIC	Type IV	Type V
	Continental rifted basins: transverse rift-faulted convergent margin	**Continental rifted basins: median rift-faulted convengent margin**	**Continental rifted basins: rift-faulted divergent margin, may be subdivided into (a) parallel, or (b) transverse basins**	**Deltas**	**Fore-arc basins**
1. Crustal zone	Contintental accreted zone with oceanic crust in early stages	Contintental accreted zone with oceanic crust in early stages	Ocean crust in early stage, then continental crust of craton and accreted zone	Ocean crust in early stage, then continental crust of craton and accreted zone	Continetal accreted crust and oceanic crust
2. Tectonic setting	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Rift faulting along a divergent, passive or pull-apart continental margin	Almost any location: divergent and convergent margins along open or confined coastal areas	Fore-arc basins located on oceanward side of the volcanic arc in subduction or consumption zone
3. Regional stress	(1st) extension and wrench compression, (2nd) extension and compression	(1st) extension and wrench compression, (2nd) extension and compression	Extension leading to rift or wrench faulting	Extension as sag develops but uncertain as to the initial cause of sag, roots being deeply buried	Compression and extension
4. Basin size, shape	Small, elongate	Small, elongate	Small to moderate, elongate	Moderate, circular to elongate	Small, elongate
5. Basin profile	Irregular	Irregular	Asymmetrical	Depocenter	Asymmetrical
6. Sediment ratio[1]	High but variable	High but variable	High	Extremely high	High
7. Architectural sequence	Rift faulting leading to linear sag, may be followd by wrench faulting	Rift faulting leading to linear sag, may be followd by wrench faulting	Linear sage with irregular profile	Roots of deltas deeply buried; extension leads to half-sag with sedimentary fill thickening seaward.	Small linear troughs
8. Special features	Large traps, and unconformities	Large traps, unconformities, and regional arches	Possible unconformities and regional source seals	None	Large traps, and unconformities
9. Basin lithology[2]	Clastic 90%, carbonate 10%	Clastic 90%, carbonate 10%	Clastic 70%, carbonate 30%	Clastic 100%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 70%, moderate 20%, deep 10%	Shallow 70%, moderate 20%, deep 10%	Deep 60%, moderate 30%, shallow 10%	Deep 65%, moderate 30%, shallow 5%	Shallow 70%, deep 20%, moderate 10%
11. Geothermal gradient	High	Normal to high	Low	Low	High
12. Temperature	Normal to high	Normal to high	Cool	Normal to low	High to normal
13. Age	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Paleogene, Neogene, and Quaternary	Upper Mesozoic, Tertiary
14. Oil and gas recovery[4]	Variable	Variable	Low	High	High but variable
15. Traps	Basement uplifts, fault blocks and combination	Basement uplifts, fault blocks and combination	Fault blocks and combination	Primarily tensional growth (roll-over) anticlines and flowage: basement not involved	Fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Low	Low	Nil
17. Propensity for natural bitumen	Low	Low	Low	Nil	Nil

Table 8. Regional distribution of heavy oil and natural bitumen (billion barrels).

[Volumes may not add to totals due to independent rounding]

Region[1]	Discovered orginal oil in place	Prospective additional	Total original oil in place
		Heavy oil	
North America…………………	650	2	651
South America…………………	1099	28	1127
Europe………………………….	75	0	75
Africa…………………………..	83	0	83
Transcaucasia…………………..	52	0	52
Middle East…………………….	971	0	971
Russia…………………………..	182	0	182
South Asia……………………...	18	0	18
East Asia……………………….	168	0	168
Southeast Asia and Oceania……	68	0	68
Total………………………..	3366	29	3396
		Natural bitumen	
North America…………………	1671	720	2391
South America…………………	2070	190	2260
Europe………………………….	17	0	17
Africa…………………………..	13	33	46
Transcaucasia…………………..	430	0	430
Middle East…………………….	0	0	0
Russia…………………………..	296	51	347
South Asia……………………...	0	0	0
East Asia……………………….	10	0	10
Southeast Asia and Oceania……	4	0	4
Total………………………..	4512	993	5505

[1] See table 6 for a list of countries reporting deposits of heavy oil and/or natural bitumen grouped by regions.

Appendixes 1–4

Appendix 1. Map Basin Name Conventions

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Amu Darya	Tadzhik
Arkla	Louisiana Salt Dome
Baikal	Lake Baikal
Barinas-Apure	Llanos de Casanare
Carnarvon	Dampier
Central Montana Uplift	Crazy Mountains
Central Sumatra	Sumatra, Central
East Java	Java, East
East Texas	East Texas Salt Dome
Eastern Venezuela	Maturin
Forest City	Salina-Forest City
Gulf of Alaska	Alaska, Gulf of
Gulf of Suez	Suez, Gulf of
Guyana	Guiana
Junggar	Zhungeer
Kutei	Mahakam
Mae Fang	Fang
Minusinsk	Minisinsk
North Caspian	Caspian, North
North Caucasus-Mangyshlak	Caucasus, North
North Egypt	Western Desert
North Sakhalin	Sakhalin, North
North Sumatra	Sumatra, North
North Ustyurt	Ust Urt
Northern North Sea	North Sea, Northern
Northwest Argentina	Argentina, Northwest
Northwest German	German, Northwest
Northwest Shelf	Dampier
Ordos	Shanganning
Progreso	Guayaquil
Sacramento	Sacramento/San Joaquin
Salinas	Salinas (Mexico)
San Joaquin	Sacramento/San Joaquin
South Adriatic	Adriatic, South
South Palawan	Palawan, South
South Sumatra	Sumatra, South
Timan-Pechora	Pechora
Turpan	Tulufan

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).—Continued

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Upper Magdalena	Magdalena, Upper
West Java	Java, West, Sunda
West of Shetlands	Shetlands, West
Western Canada Sedimentary	Alberta
Yukon-Kandik	Yukon/Kandik

The following basins listed in bold type are from the digital mapping file of St. John (1996) and require further explanation:

- **Anadarko**: includes provinces more commonly known as the *Anadarko,* Central Kansas Uplift, Chautauqua Platform, *Las Animas Arch,* Nemaha Anticline-Cherokee Basin, *Ozark Uplift,* Sedgwick, and South Oklahoma Folded Belt (provinces in italics report neither heavy oil nor natural bitumen.)

- **Sacramento/San Joaquin**: separated into two distinct provinces, Sacramento and San Joaquin.

- **North Sea, Southern**: : includes both the Anglo-Dutch and Southern North Sea basins.

- **South Adriatic**: includes both the Durres and South Adriatic basins.

Other comments:

Three separate outlines for Marathon, Ouachita, and Eastern Overthrust are shown as a common province Marathon/Ouachita/Eastern Overthrust in the original St John (1996) but only Ouachita Basin had reported volumes of natural bitumen resources.

Deposits reported for Eastern Venezuela basin include deposits on the island of Trinidad, which are a likely extension of the rock formations from the surface expression of the basin outline.

The plates attach the name of Barinas Apure to the polygonal province labeled Llanos de Casanare in St. John (1996). Barinas Apure is the province name commonly used in Venezuela and Llanos de Casanare is the province name commonly used in Colombia for the same geologic province.

Appendix 2. Basins, Basin Type and Location of Basins having Heavy Oil and Natural Bitumen Deposits

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.

Geological province	Klemme basin type	Country	State/Province	Other names
Aegian	IIIBc	Greece		North Aegean Trough (North Aegean Sea Basin)
Akita	IIIBa	Japan		Akita Basin, Japan Accreted Arc/Accreted Terrane
Amu-Darya	IICa	Tajikistan, Uzbekistan		Tadzhik, Surkhan-Vaksh, Badkhyz High (Murgab Basin), Afghan-Tajik
Amur	IIIBc	Georgia		
Ana Maria	IIIBb	Cuba		Zaza Basin, Greater Antilles Deformed Belt
Anabar-Lena	IIA	Russia		
Anadarko	IIA	United States	Kans.	
Anadyr	IIIBb	Russia		
Angara-Lena	IIA	Russia		
Anglo-Dutch	IIB	Netherlands		Central Graben, North Sea, Southern
Appalachian	IIA	United States	Ky., N.Y.	
Aquitaine	IIIA	France		Ales, Aquitaine, Lac Basin, Parentis, Massif Central, Pyrenean Foothills-Ebro Basin
Arabian	IICa	Bahrain, Iran, Iraq, Jordan, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria		Arabian Basin, Rub Al Khali, Aneh Graben, Aljafr Sub-basin, Oman Platform, Mesopotamian Foredeep, Palmyra Zone, Oman Sub-Basin, Euphrates/Mardin, Ghaba Salt Basin, Greater Ghawar Uplift, Haleb, Qatar Arch, South Oman Salt Basin, Widyan Basin
Arkla	IICc	United States	Ark., La.	Louisiana Salt Dome
Arkoma	IIA	United States	Ark., Okla.	
Assam	IICb	India		
Atlas	IICb	Algeria		Moroccan-Algerian-Tunisian Atlas, Hodna-Constantine
Bahia Sul	IIIC	Brazil		J Equitinhonha
Baikal	IIIA	Russia		Lake Baikal
Balearic	IIIA	Spain		Western Mediterranean, Gulf of Valencia, Barcelona Trough (Catalano-Balearic Basin), Iberic Cordillera
Baltic	I	Sweden		
Baluchistan	IICb	Pakistan		Sulaiman-Kirthar
Barbados	V	Barbados		Lesser Antilles, Northeast Caribbean Deformed Belt
Barinas-Apure	IIA	Venezuela, Colombia		Barinas-Apure Basin, Llanos de Casanare
Barito	IIIBa	Indonesia		Barito Basin
Bawean	IIIBa	Indonesia		
Beibu Gulf	IIIBa	China		Beibuwan (Gulf of Tonkin) Basin
Bengal	IICa	Bangladesh, India		Bengal (Surma Sub-basin), Tripura-Cachar, Barisal High (Bengal Basin), Ganges-Brahmaputra Delta
Beni	IIA	Bolivia		Foothill Belt
Big Horn	IIA	United States	Mont., Wyo.	
Black Mesa	IIB	United States	Ariz.	Dry Mesa, Dineh Bi Keyah
Black Warrior	IIA	United States	Ala., Miss.	
Bohai Gulf	IIIA	China		Bohai Wan (Huabei-Bohai) Basin, Huabei, Pohal, Luxi Jiaoliao Uplift

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Bombay	IIIC	India		
Bonaparte Gulf	IIIC	Australia		Berkeley Platform (Bonaparte Basin)
Bone Gulf	IIIBa	Indonesia		Bone
Bresse	IIIA	France		Jura Foldbelt
Browse	IIIC	Australia		
Brunei-Sabah	IICc	Brunei, Malaysia		Baram Delta
Cabinda	IIIC	Angola, Congo (Brazzaville), Democratic Republic of Congo (Kinshasa)		Lower Congo Basin, West-Central Coastal
Caltanisetta	IICb	Italy, Malta		Caltanissetta Basin, Ibleian Platform, Sicilian Depression
Cambay	IIIA	India		Cambay North, Bikaner-Nagam, Bombay (in part)
Campeche	IICc	Mexico		Tabasco-Campeche, Yucatan Boderland and Platform, Tobasco, Campeche-Sigsbee Salt, Villahermosa Uplift
Campos	IIIC	Brazil		Cabo Frio High (Campos Basin)
Cantabrian	IIIA	Spain		Offshore Cantabrian Foldbelt (Cantabrian Zone), Spanish Trough-Cantabrian Zone
Carnarvon	IIIC	Australia		Dampier, Northwest Shelf, Carnarvon Offshore, Barrow-Dampier Sub-Basin
Carpathian	IICb	Austria, Czech Republic, Poland, Ukraine		Carpathian Flysch, Carpathian Foredeep, Bohemia, Carpathian-Balkanian
Celtic	IIIA	Ireland		Celtic Sea Graben System, Ireland-Scotland Platform
Central Coastal	IIIBb	United States	Calif.	Coastal, Santa Cruz, Salinas Valley, Northern Coast Range
Central Kansas Uplift	IIA	United States	Kans.	Anadarko
Central Montana Uplift	IIA	United States	Mont.	Crazy Mountains
Central Sumatra	IIIBa	Indonesia		Central Sumatra Basin
Ceram	IICa	Indonesia		North Seram Basin, Banda Arc
Channel Islands	IIIBb	United States		Southern California Borderlands
Chao Phraya	IIIA	Thailand		Phitsanulok Basin, Thailand Mesozoic Basin Belt
Chautauqua Platform	IIA	United States	Okla.	Anadarko
Cincinnati Arch	I	United States	Ky., Ohio	
Cook Inlet	IIIBa	United States	Alaska	Susitna Lowlands
Cuanza	IIIC	Angola		Kwanza Basin, West-Central Coastal
Cuyo	IIB	Argentina		Alvear Sub-basin (Cuyo Basin), Cuyo-Atuel
Dead Sea	IICa	Israel, Jordan		Syrian -African Arc, Levantine, Jafr-Tabuk, Sinai
Denver	I	United States	Colo., Nebr.	Denver-Julesberg
Diyarbakir	IICa	Syria, Turkey		Bozova-Mardin High (Southeast Turkey Fold Belt), Euphrates/Mardin, Zagros Fold Belt
Dnieper-Donets	IIIA	Ukraine		Dnepr-Donets Graben
Doba	IIIA	Chad		
Durres	IICb	Albania		Ionian Basin (zone), South Adriatic, Pre-Adriatic
East China	IIIBa	China, Taiwan		Diaoyu Island Depression (East China Sea Basin)
East Java	IIIBa	Indonesia		Bawean Arch (East Java Basin)
East Texas	IICc	United States	Tex.	East Texas Salt Dome, Ouachita Fold Belt
Eastern Venezuela	IICa	Venezuela, Trinidad and Tobago		Maturin, Eastern Venezuela Basin, Orinoco Oil Belt, Guarico Sub-basin, Trinidad-Tabago

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Espirito-Santo	IIIC	Brazil		Abrolhos Bank Sub-Basin (Espirito Santo Basin)
Fergana	IIIBc	Kyrgyzstan, Tajikistan, Uzbekistan		
Florida-Bahama	IIIC	Cuba, United States	Fla.	Almendares-San Juan Zone, Bahia Honda Zone, Llasvvillas Zone, Florida Platform, Greater Antilles Deformed Belt
Forest City	I	United States	Kans., Nebr.	Salina-Forest City, Salina, Chadron Arch
Fort Worth	IIA	United States	Tex.	Bend Arch, Fort Worth Syncline, Llano Uplift, Ouachita Overthrust
Gabon	IIIC	Gabon		Gabon Coastal Basin (Ogooue Delta), West-Central Coastal
Gaziantep	IICa	Syria, Turkey		
Ghana	IIIC	Ghana, Nigeria		Benin-Dahomey, Dahomey Coastal
Gippsland	IIIA	Australia		Gippsland Basin
Green River	IIA	United States	Colo., Wyo.	
Guangxi-Guizou	IIB	China		Bose (Baise) Basin, South China Fold Belt
Gulf Coast	IICc	United States	La., Tex.	Mid-Gulf Coast, Ouachita Folded Belt, Burgos
Gulf of Alaska	V	United States	Alaska	
Gulf of Suez	IIIA	Egypt		Gulf of Suez Basin, Red Sea Basin
Guyana	IIIC	Suriname		Guiana, Bakhuis Horst, Guyana-Suriname
Illinois	I	United States	Ill., Ky.	
Indus	IICb	India		Punjab (Bikaner-Nagaur Sub-basin), West Rajasthan
Ionian	IICb	Greece		Epirus, Peloponesus
Irkutsk	IIA	Russia		
Jeanne d'Arc	IIIC	Canada	N.L.	Labrador-Newfoundland Shelf
Jianghan	IIIA	China		Tung-T'Ing Hu
Junggar	IIIA	China		Zhungeer, Anjihai-Qigu-Yaomashan Anticlinal Zone (Junggar)
Kansk	IIA	Russia		
Krishna	IIIC	India		Krishna-Godavari Basin
Kura	IIIBc	Azerbaijan, Georgia		Kura Basin
Kutei	IIIBa	Indonesia		Mahakam
Kuznets	IIB	Russia		
Laptev	IIB	Russia		
Los Angeles	IIIBb	United States	Calif.	
MacKenzie	IV	Canada	N.W.T.	Beaufort Sea, MacKenzie Delta
Mae Fang	IIIA	Thailand		Fang, Mae Fang Basin, Tenasserim-Shan
Maracaibo	IIIBc	Venezuela, Colombia		Maracaibo Basin, Catatumbo
Mauritius-Seychelles	IIIC	Seychelles		
Mekong	IIIC	Vietnam		Mekong Delta Basin
Michigan	I	United States	Mich.	
Middle Magdalena	IIIBc	Colombia		Middle Magdalena Basin
Minusinsk	IIB	Russia		Minisinsk
Mississippi Salt Dome	IICc	United States	Ala., Miss.	
Moesian	IICb	Bulgaria, Moldova, Romania		Moesian Platform-Lom Basin, Alexandria Rosiori Depression (Moesian Platform), Carpathian-Balkanian, West Black Sea

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Molasse	IICb	Austria, Germany, Italy, Switzerland		Molasse Basin
Morondava	IIIC	Madagascar		
Mukalla	IIIC	Yemen		Sayhut Basin, Masila-Jeza
Natuna	IIIA	Indonesia		
Nemaha Anticline-Cherokee Basin	IIA	United States	Kans., Mo.	Anadarko
Neuquen	IIB	Argentina		Agrio Fold Belt (Neuquen Basin)
Niger Delta	IV	Cameroon, Equatorial Guinea, Nigeria		Abakaliki Uplift (Niger Delta)
Niigata	IIIBa	Japan		Niigata Basin, Yamagata Basin, Japan Volcanic Arc/Accreted Terrane
Nile Delta	IV	Egypt		Nile Delta Basin
North Caspian	IICa	Kazakhstan, Russia		Akatol' Uplift, Alim Basin, Beke-Bashkuduk Swell Pri-Caspian, Kobyskol' Uplift, South Emba, Tyub-Karagan
North Caucasus-Mangyshlak	IICa	Russia		Indolo-Kuban-Azov-Terek-Kuma Sub-basins, North Buzachi Arch, Middle Caspian, North Caucasus
North Egypt	IICa	Egypt		Western Desert, Abu Gharadiq
North Sakhalin	IIIBb	Russia		Sakhalin North
North Slope	IICc	United States	Alaska	Arctic Coastal Plains, Interior Lowlands, Northern Foothills, Southern Foothills, Colville
North Sumatra	IIIBa	Indonesia		North Sumatra Basin
North Ustyurt	IIB	Kazakhstan		Ust-Urt
Northern North Sea	IIIA	Norway, United Kingdom		Viking Graben, North Sea Graben
Northwest Argentina	IIA	Argentina		Carandaitycretaceous Basin
Northwest German	IIB	Germany		Jura Trough, West Holstein
Olenek	I	Russia		
Ordos	IIA	China		Shanganning, Qinling Dabieshan Fold Belt
Oriente	IIA	Peru		Acre, Maranon, Upper Amazon
Otway	IIIC	Australia		
Ouachita Overthrust	IIA	United States	Ark.	
Palo Duro	IIA	United States	N. Mex.	Tucumcari
Pannonian	IIIBc	Bosnia and Herzegovina, Croatia, Hungary, Romania, Serbia		Backa Sub-basin (Pannonian Basin)
Paradox	IIB	United States	Utah	
Paris	IIB	France		Anglo-Paris Basin
Pearl River	IIIC	China		Dongsha Uplift (Pearl River Basin), Pearl River Mouth, South China Continental Slope
Pelagian	IICa	Tunisia, Libya		
Permian	IIA	United States	N. Mex., Tex.	Ouachita Fold Belt, Bend Arch, Delaware, Midland
Peten-Chiapas	IICc	Guatemala		Chapayal (South Peten) Basin, North Peten (Paso Caballos), Sierra De Chiapas-Peten, Yucatan Platform
Piceance	IIA	United States	Colo.	
Po	IICb	Italy		Crema Sub-Basin (Po Basin)
Polish	IIIA	Poland		Danish-Polish Marginal Trough, German-Polish

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Potiguar	IIIC	Brazil		Boa Vista Graben (Potiguar Basin), North-Northeastern Region
Potwar	IICb	Pakistan		Bannu Trough (Potwar Basin), Kohat-Potwar
Powder River	IIA	United States	Mont., Wyo.	
Pripyat	IIIA	Belarus		Pripyat Graben
Progreso	IIIBb	Ecuador		Guayaquil, Gulf Of Gayaquil, Jambeli Sub-basin of Progresso Basin, Santa Elena
Putumayo	IIA	Colombia, Ecuador		Napo, Cuenca Oriente Ecuatoriana
Rhine	IIIA	France, Germany		Upper Rhine Graben
Sacramento	IIIBb	United States	Calif.	Sacramento-San Joaquin
Salawati	IICa	Indonesia		Salawati Basin, Bintuni-Salawati
Salinas	IICc	Mexico		Isthmus Of Tehuantepec, Salinas Sub-basin, Isthmus Saline, Saline Comalcalco
San Joaquin	IIIBb	United States	Calif.	Sacramento-San Joaquin
San Jorge	IIIA	Argentina		Rio Mayo, San Jorge Basin
San Juan	IIB	United States	Ariz., Colo., N. Mex.	
Santa Maria	IIIBb	United States	Calif.	
Santos	IIIC	Brazil		
Sarawak	IICc	Malaysia		Central Luconia Platform
Sedgwick	IIA	United States	Kans.	Anadarko
Senegal	IIIC	Senegal		Bove-Senegal Basins
Sergipe-Alagoas	IIIC	Brazil		Sergipe-Alagoas Basin
Shumagin	V	United States	Alaska	
Sirte	IIIA	Libya		Agedabia Trough (Sirte Basin)
Songliao	IIIA	China		
South Adriatic	IICb	Italy		Adriatic, Marche-Abruzzi Basin (Pede-Apenninic Trough), Plio-Pleist Foredeep, Scaglia
South African	IIIC	South Africa		Agulhas Arch (South African Coastal Basin)
South Burma	IIIBb	Burma		Central Burma Basin, Irrawaddy
South Caspian	IIIBc	Azerbaidjan		South Caspian OGP (Apsheron-Kobystan Region), Emba, Guriy Region
South Oklahoma Folded Belt	IIA	United States	Okla., Tex.	Anadarko
South Palawan	IIIBa	Philippines		China Sea Platform, Palawan Shelf
South Sumatra	IIIBa	Indonesia		Central Palembang Depression (South Sumatra Basin)
South Texas Salt Dome	IICc	United States	Tex.	
South Yellow Sea	IIIA	China		Central Uplift (South Huanghai Basin), Subei Yellow Sea
Southern North Sea	IIB	United Kingdom		Central Graben (North Sea Graben system), Dutsh Bank Basin (East Shetland Platform), Witch Ground Graben
Sudan	IIIA	Sudan		Kosti Sub-Basin (Melut Basin), Muglad Basin, Sudd Basin
Sunda	IIIBa	Indonesia		
Surat	IIB	Australia		
Sverdrup	IICc	Canada	N.W.T.	Mellville
Taiwan	IIIBa	Taiwan		Taihsi Basin

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Talara	IIIBb	Peru		Talara Basin
Tampico	IICc	Mexico		Tampico-Tuxpan Embayment, Chicontepec, Tampico-Misantla
Tarakan	IIIBa	Indonesia		Bera Sub-basin (Tarakan Basin), Pamusian-Tarakan
Taranto	IICb	Italy		Abruzzi Zone (Apennine Range). Marche-Abruzzi Basin (Pede-Apenninic Trough), Latium, Calabrian
Tarfaya	IIIC	Morocco		Aaiun-Tarfaya
Tarim	IIIA	China		
Thrace	IIIBc	Turkey		Thrace-Gallipoli Basin, Zagros Fold Belt
Timan-Pechora	IIB	Russia		Belaya Depression (Ural Foredeep), Brykalan Depression, Pechora-Kozhva Mega-Arch, Varendey-Adz'va
Timimoun	IIB	Algeria		Sbaa
Tonga	IIIBa	Tonga		
Tunguska	I	Russia		Baykit Antecline
Turpan	IIIA	China		Tulufan
Tyrrhenian	IIIA	Italy		
Uinta	IIA	United States	Utah	
Upper Magdalena	IIIBc	Colombia		Upper Magdalena Basin
Ventura	IIIBb	United States	Calif.	Santa Barbara Channel
Veracruz	IIIC	Mexico		
Verkhoyansk	IIA	Russia		
Vienna	IIIBc	Austria, Slovakia		Bohemia
Vilyuy	IIA	Russia		
Volga-Ural	IIA	Russia		Aksubayevo-Nurlaty Structural Zone, Bashkir Arch, Belaya Depression, Melekess Basin, Tatar Arch, Vishnevo-Polyana Terrace
Washakie	IIA	United States	Wyo.	
West Java	IIIBa	Indonesia		Arjuna Sub-Basin (West Java Basin), Northwest Java
West of Shetlands	IIIC	United Kingdom		Faeroe, West of Shetland
West Siberia	IIB	Russia		West Siberia
Western Canada Sedimentary	IIA	Canada, United States	Alta., Mont., Sask.	Alberta, Western Canada Sedimentary, Sweetgrass Arch
Western Overthrust	IIA	United States	Ariz., Mont., Nev., Utah	Central Western Overthrust, Great Basin Province, Southwest Wyoming, South Western Overthrust
Williston	I	Canada, United States	N. Dak., Sask.	Sioux Uplift
Wind River	IIA	United States	Wyo.	
Yari	IIA	Colombia		Yari Basin
Yenisey-Khatanga	IIA	Russia		
Yukon-Kandik	IIIBb	United States	Alaska	Yukon-Koyukuk
Zagros	IICa	Iran, Iraq		Zagros Fold Beltzagros or Iranian Fold Belt, Sinjar Trough, Bozova-Mardin High, Euphrates/Mardin

Appendix 3. Klemme Basin Classificaton Figure from Plate 1

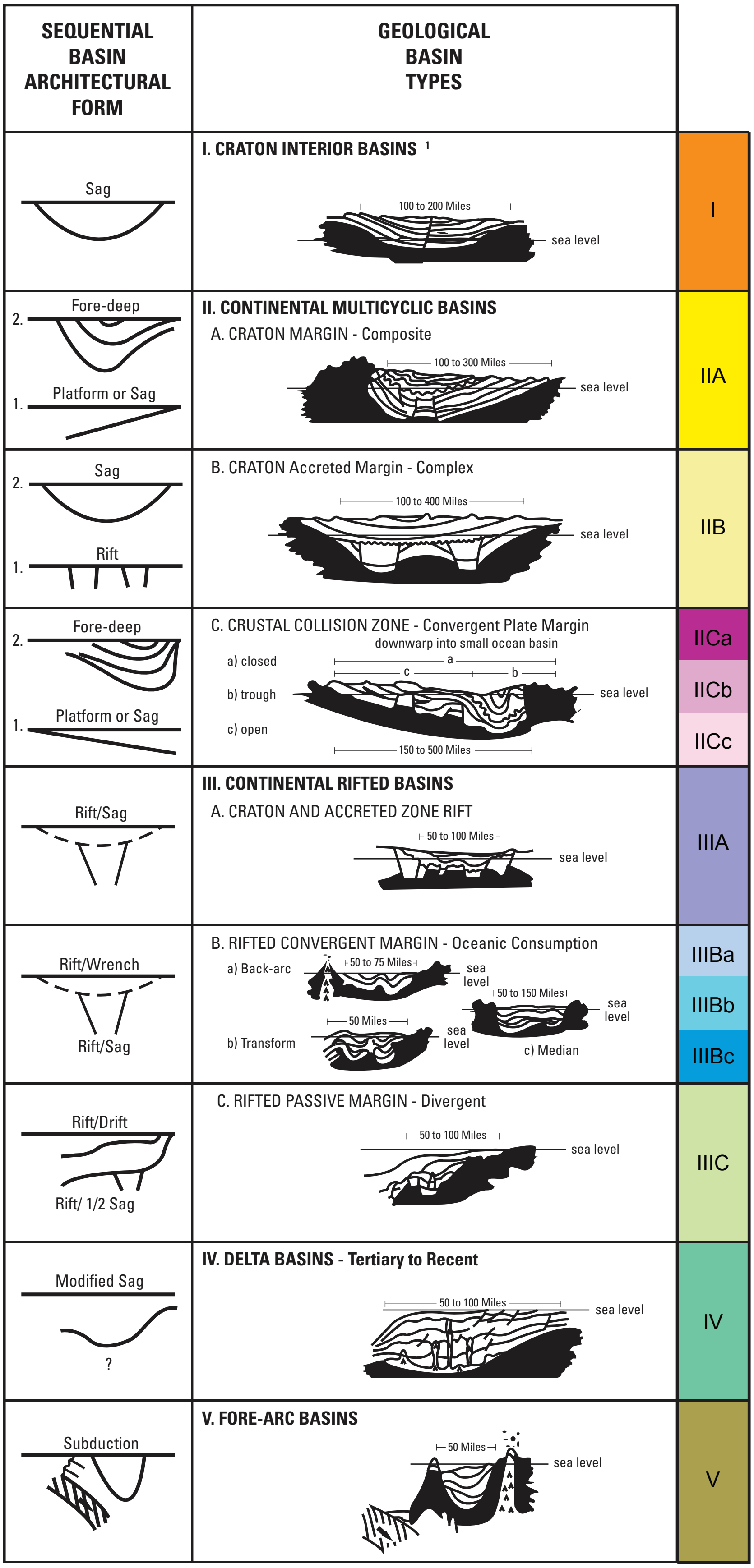

Figure 2-1. Diagram of Klemme basin types from plate 1. Modified from St. John, Bally, and Klemme (1984).

[1] Cincinati Arch is classified as I-Arch

Appendix 4. Tables from the Plates

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Arabian	IICa	842	842				
2	Eastern Venezuela	IICa	593	566	27.7	2,090	1,900	190
3	Maracaibo	IIIBc	322	322		169	169	
4	Campeche	IICc	293	293		0.060	0.060	
5	Bohai Gulf	IIIA	141	141		7.63	7.63	
6	Zagros	IICa	115	115				
7	Campos	IIIC	105	105				
8	West Siberia	IIB	88.4	88.4				
9	Tampico	IICc	65.3	65.3				
10	Western Canada Sedimentary	IIA	54.9	54.9		2,330	1,630	703
11	Timan-Pechora	IIB	54.9	54.9		22.0	22.0	
12	San Joaquin	IIIBb	53.9	53.9		< 0.01	< 0.01	
13	Putumayo	IIA	42.4	42.4		0.919	0.919	
14	Central Sumatra	IIIBa	40.6	40.6				
15	North Slope	IICc	37.0	37.0		19.0	19.0	
16	Niger Delta	IV	36.1	36.1				
17	Los Angeles	IIIBb	33.4	33.4		< 0.01	< 0.01	< 0.01
18	North Caspian	IICa	31.9	31.9		421	421	
19	Volga-Ural	IIA	26.1	26.1		263	263	
20	Ventura	IIIBb	25.2	25.2		0.505	0.505	
21	Gulf of Suez	IIIA	24.7	24.7		0.500	0.500	
22	Northern North Sea	IIIA	22.8	22.8		10.9	10.9	
23	Gulf Coast	IICc	19.7	19.7				
24	Salinas	IICc	16.6	16.6				
25	Middle Magdalena	IIIBc	16.4	16.4				
26	Pearl River	IIIC	15.7	15.7				
27	North Ustyurt	IIB	15.0	15.0				
28	Brunei-Sabah	IICc	14.7	14.7				
29	Diyarbakir	IICa	13.5	13.5				

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.—Continued

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
30	Northwest German	IIB	9.48	9.48				
31	Barinas-Apure	IIA	9.19	9.19		0.38	0.38	
32	North Caucasus-Mangyshlak	IICa	8.60	8.60		0.060	0.060	
33	Cambay	IIIA	8.28	8.28				
34	Santa Maria	IIIBb	8.06	8.06		2.03	2.02	< 0.01
35	Central Coastal	IIIBb	8.01	8.01		0.095	0.025	0.070
36	Big Horn	IIA	7.78	7.78				
37	Arkla	IICc	7.67	7.67				
38	Moesian	IICb	7.39	7.39				
39	Assam	IICb	6.16	6.16				
40	Oriente	IIA	5.92	5.92		0.250	0.250	
41	Molasse	IICb	5.79	5.79		0.010	0.010	
42	Doba	IIIA	5.35	5.35				
43	Morondava	IIIC	4.75	4.75		2.21	2.21	
44	Florida-Bahama	IIIC	4.75	4.75		0.48	0.48	
45	Southern North Sea	IIB	4.71	4.71				
46	Durres	IICb	4.70	4.70		0.37	0.37	
47	Caltanisetta	IICb	4.65	4.65		4.03	4.03	
48	Neuquen	IIB	4.56	4.56				
49	North Sakhalin	IIIBb	4.46	4.46		< 0.01	< 0.01	
50	Cabinda	IIIC	4.43	4.43		0.363	0.363	

Table 4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Western Canada Sedimentary	IIA	2,330	1,630	703
2	Eastern Venezuela	IICa	2,090	1,900	190
3	North Caspian	IICa	421	421	
4	Volga-Ural	IIA	263	263	
5	Maracaibo	IIIBc	169	169	
6	Tunguska	I	59.5	8.19	51.3
7	Ghana	IIIC	38.3	5.74	32.6
8	Timan-Pechora	IIB	22.0	22.0	
9	North Slope	IICc	19..0	19.0	
10	Uinta	IIA	11.7	7.08	4.58
11	Northern North Sea	IIIA	10.9	10.9	
12	South Caspian	IIIBc	8.84	8.84	
13	Bohai Gulf	IIIA	7.63	7.63	
14	Paradox	IIB	6.62	4.26	2.36
15	Black Warrior	IIA	6.36	1.76	
16	South Texas Salt Dome	IICc	4.88	3.87	1.01
17	Cuanza	IIIC	4.65	4.65	
18	Bone Gulf	IIIBa	4.46	4.46	
19	Caltanisetta	IICb	4.03	4.03	
20	Nemaha Anticline-Cherokee Basin	IIA	2.95	0.70	2.25
21	Morondava	IIIC	2.21	2.21	
22	Yenisey-Khatanga	IIA	2.21	2.21	
23	Santa Maria	IIIBb	2.03	2.02	<0.01
24	Junggar	IIIA	1.59	1.59	
25	Tarim	IIIA	1.25	1.25	
26	West of Shetlands	IIIC	1.00	1.00	
27	Putumayo	IIA	0.919	0.919	
28	Illinois	I	0.890	0.300	0.590
29	South Oklahoma Folded Belt	IIA	0.885	0.058	0.827
30	South Adriatic	IICb	0.510	0.510	
31	Ventura	IIIBb	0.505	0.505	
32	Gulf of Suez	IIIA	0.500	0.500	
33	Florida-Bahama	IIIC	0.477	0.477	

Attachment 21

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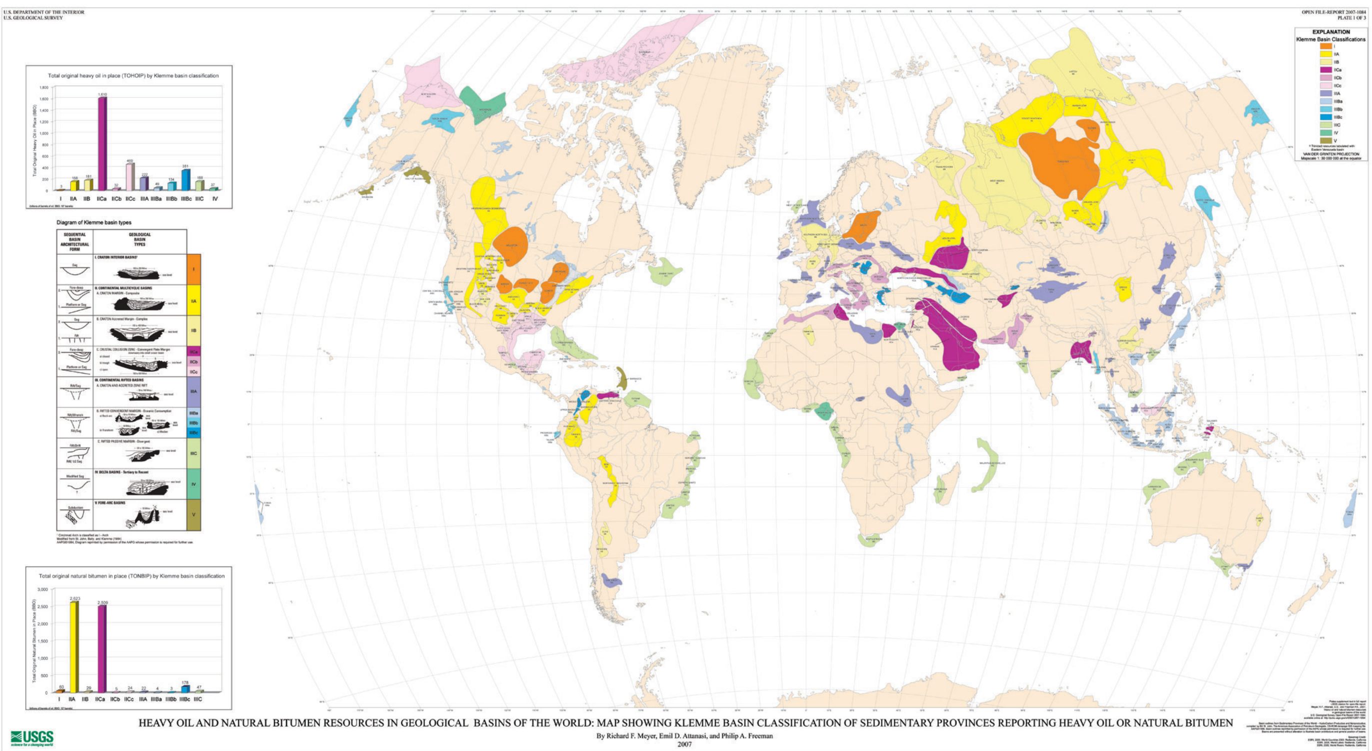
Heavy Oil and Natural Bitumen Resources in Geological Basins of the World



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Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

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Suggested citation:
Meyer, R.F., Attanasi, E.D., and Freeman, P.A., 2007, Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084, available online at http://pubs.usgs.gov/of/2007/1084/.

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4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3 36

Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

Abstract

Heavy oil and natural bitumen are oils set apart by their high viscosity (resistance to flow) and high density (low API gravity). These attributes reflect the invariable presence of up to 50 weight percent asphaltenes, very high molecular weight hydrocarbon molecules incorporating many heteroatoms in their lattices. Almost all heavy oil and natural bitumen are alteration products of conventional oil. Total resources of heavy oil in known accumulations are 3,396 billion barrels of original oil in place, of which 30 billion barrels are included as prospective additional oil. The total natural bitumen resource in known accumulations amounts to 5,505 billion barrels of oil originally in place, which includes 993 billion barrels as prospective additional oil. This resource is distributed in 192 basins containing heavy oil and 89 basins with natural bitumen. Of the nine basic Klemme basin types, some with subdivisions, the most prolific by far for known heavy oil and natural bitumen volumes are continental multicyclic basins, either basins on the craton margin or closed basins along convergent plate margins. The former includes 47 percent of the natural bitumen, the latter 47 percent of the heavy oil and 46 percent of the natural bitumen. Little if any heavy oil occurs in fore-arc basins, and natural bitumen does not occur in either fore-arc or delta basins.

Introduction

Until recent years conventional, light crude oil has been abundantly available and has easily met world demand for this form of energy. By year 2007, however, demand for crude oil worldwide has substantially increased, straining the supply of conventional oil. This has led to consideration of alternative or insufficiently utilized energy sources, among which heavy crude oil and natural bitumen are perhaps the most readily available to supplement short- and long-term needs. Heavy oil has long been exploited as a source of refinery feedstock, but has commanded lower prices because of its lower quality relative to conventional oil. Natural bitumen is a very viscous crude oil that may be immobile in the reservoir. It typically requires upgrading to refinery feedstock grade (quality). When natural bitumen is mobile in the reservoir, it is generally known as extra-heavy oil. As natural asphalt, bitumen has been exploited since antiquity as a source of road paving, caulk, and mortar and is still used for these purposes in some parts of the world. The direct use of mined asphalt for road paving is now almost entirely local, having been replaced by manufactured asphalt, which can be tailored to specific requirements.

This study shows the geological distribution of known heavy oil and natural bitumen volumes by basin type. These data are presented to advance a clearer understanding of the relationship between the occurrence of heavy oil and natural bitumen and the type of geological environment in which these commodities are found. The resource data presented were compiled from a variety of sources. The data should not be considered a survey of timely resource information such as data published annually by government agencies and public reporting services. With the exception of Canada, no such data source on heavy oil and natural bitumen accumulations is available. The amounts of heavy oil yet unexploited in known deposits represent a portion of future supply. To these amounts may be added the heavy oil in presently poorly known and entirely unexploited deposits. Available information indicates cumulative production accounts for less than 3 percent of the discovered heavy oil originally in place and less than 0.4 percent of the natural bitumen originally in place.

Terms Defined for this Report

- Conventional (light) Oil: Oil with API gravity greater than 25°.
- Medium Oil: Oil with API gravity greater than 20°API but less than or equal to 25°API.
- Heavy Oil: Oil with API gravity between 10°API and 20°API inclusive and a viscosity greater than 100 cP.
- Natural Bitumen: Oil whose API gravity is less than 10° and whose viscosity is commonly greater than 10,000 cP. It is not possible to define natural bitumen on the basis of viscosity alone because much of it, defined on the basis of gravity, is less viscous than 10,000 cP. In addition, viscosity is highly temperature-

dependent (fig. 1), so that it must be known whether it is measured in the reservoir or in the stock tank. In dealing with Russian resources the term natural bitumen is taken to include both maltha and asphalt but excludes asphaltite.

- Total Original Oil in Place (TOOIP): Both discovered and prospective additional oil originally in place.
- Original Oil in Place-Discovered (OOIP-Disc.): Discovered original oil in place.
- Reserves (R): Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, and quantities of petroleum that are anticipated to be technically but not necessarily commercially recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian reserve classes A, B, and C1 are included here (See Grace, Caldwell, and Hether,1993, for an explanation of Russian definitions.)
- Prospective Additional Oil in Place: The amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study.
- Original Reserves (OR): Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimately recoverable, particularly in the case of new discoveries.

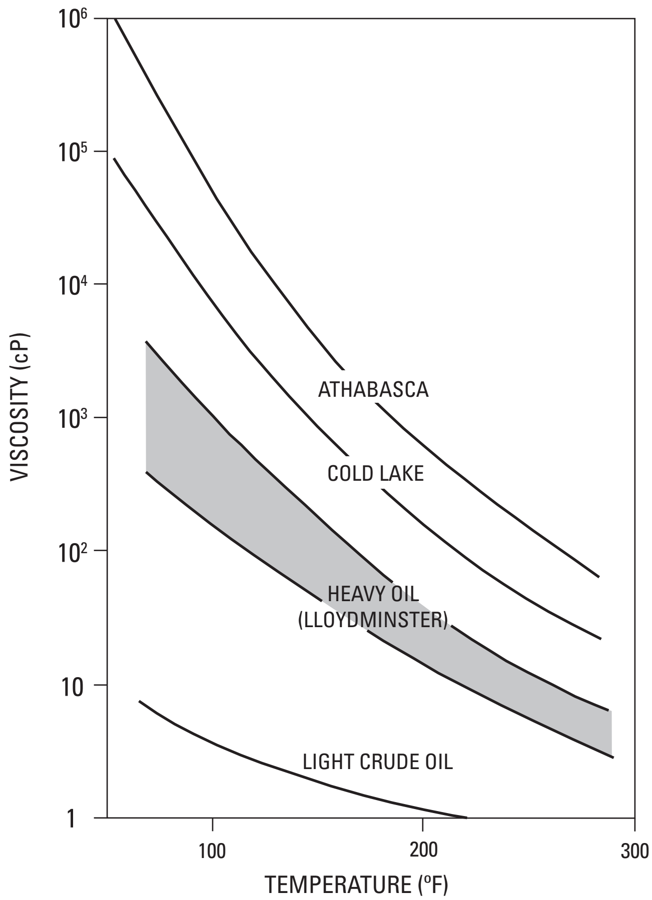

Figure 1. Response of viscosity to change in temperature for some Alberta oils (cP, centipoise), (Raicar and Proctor, 1984).

Chemical and Physical Properties

Fundamental differences exist between natural bitumen, heavy oil, medium oil, and conventional (light) oil, according to the volatilities of the constituent hydrocarbon fractions: paraffinic, naphthenic, and aromatic. When the light fractions are lost through natural processes after evolution from organic source materials, the oil becomes heavy, with a high proportion of asphaltic molecules, and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen. Therefore, heavy oil, regardless of source, always contains the heavy fractions, the asphaltics, which consist of resins, asphaltenes, and preasphaltenes (the carbene-carboids) (Yen, 1984). No known heavy oil fails to incorporate asphaltenes. The large asphaltic molecules define the increase or decrease in the density and viscosity of the oil. Removal or reduction of asphaltene or preasphaltene drastically affects the rheological properties of a given oil and its aromaticity (Yen, 1984). Asphaltenes are defined formally as the crude oil fraction that precipitates upon addition of an n-alkane, usually n-pentane or n-heptane, but remains soluble in toluene or benzene. In the crude oil classification scheme of Tissot and Welte (1978), the aromatic-asphaltics and aromatic-naphthenics characterize the heavy oil and natural bitumen deposits of Canada and Venezuela and are the most important of all crude oil classes with respect to quantity of resources. The aromatic-intermediate class characterizes the deposits of the Middle East (Yen, 1984).

Some of the average chemical and physical properties of conventional, medium, and heavy crude oils and natural bitumen are given in table 1, in order to show their distinguishing characteristics. The data are derived from multiple sources, some old and others adhering to standards employed in different countries. The conversion factors outlined in table 2 were used to convert published data to a uniform standard. Some of the properties in table 1 are important with respect to heavy oil and natural recovery from the ground and other properties in table 1 serve as the basis for decisions for upgrading and refinery technologies. Moving across table 1 from conventional oil to natural bitumen, increases may be seen in density (shown as reductions in API gravity), coke, asphalt, asphaltenes, asphaltenes + resins, residuum yield (percent volume), pour point, dynamic viscosity, and the content of copper, iron, nickel, vanadium among the metals and in nitrogen and sulfur among the non-metals. Values diminish for reservoir depth, gasoline and gas-oil yields, and volatile organic compounds (VOC and BTEX –Benzene, Toluene, Ethylbenzene, and

Xylenes). The significance of these differences is often reflected in the capital and operating expenses required for the recovery, transportation, product processing, and environmental mitigation of the four oil types. The principal sources of analytical data for table 1 are Environmental Technology Centre (2003), Hyden (1961), Oil & Gas Journal Guide to Export Crudes (2006), U.S. Department of Energy, National Energy Technology Laboratory (1995), and various analyses published in technical reports.

The resins and asphaltenes play an important role in the accumulation, recovery, processing, and utilization of petroleum. The resins and asphaltenes are the final form of naphtheno-aromatic molecules. The carbon skeleton appears to comprise three to five polyaromatic sheets, with some heterocyclic (N-S-O) compounds. These crystallites may combine to form high molecular weight aggregates, with the high viscosity of heavy oils related to the size and abundance of the aggregates. Most asphaltenes are generated from kerogen evolution in response to depth and temperature increases in sedimentary basins. Different types of asphaltenes may be derived from the main kerogen types. Asphaltenes are not preferentially mobilized, as are light hydrocarbons during migration from source rocks to reservoir beds, where they are less abundant if the crude oil is not degraded (Tissot, 1981).

Some heavy oil and natural bitumen originates with chemical and physical attributes shown in table 1 as immature oil which has undergone little if any secondary migration. The greatest amount of heavy oil and natural bitumen results from the bacterial degradation under aerobic conditions of originally light crude oils at depths of about 5,000 feet or less and temperatures below 176°F. The consequence of biodegradation is the loss of most of the low molecular weight volatile paraffins and naphthenes, resulting in a crude oil that is very dense, highly viscous, black or dark brown, and asphaltic. An active water supply is required to carry the bacteria, inorganic nutrients, and oxygen to the oil reservoir, and to remove toxic by-products, such as hydrogen sulfide, with low molecular weight hydrocarbons providing the food (Barker, 1979). The low molecular weight components also may be lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface (Barker, 1979). The importance of this process to the exploitation of heavy oil and natural bitumen lies in the increase of NSO (nitrogen-sulfur-oxygen) compounds in bacterially-altered crude oil and the increase in asphaltenes (Kallio, 1984).

Bacterial degradation of crude oil may also take place under anaerobic conditions, thus obviating the need for a fresh water supply at shallow depths (Head, Jones, and Larter, 2003; Larter and others, 2006). This proposal envisions degradation even of light oils at great depths so long as the maximum limiting temperature for bacterial survival is not exceeded. This theory does not account in any obvious way for the high percentage in heavy oil and natural bitumen of polar asphaltics, that is, the resins and asphaltenes.

Oil mass loss entailed in the formation of heavy oil and natural bitumen deposits has been the subject of numerous research studies. Beskrovnyi and others (1975) concluded that three to four times more petroleum was required than the reserves of a natural bitumen for a given deposit. Based upon material balance calculations in the Dead Sea basin, Tannenbaum, Starinsky, and Aizenshtat (1987) found indications that 75% of the original oil constituents in the C15+ range had been removed as a result of alteration processes. By accounting for the lower carbon numbers as well, they estimated that the surface asphalts represented residues of only 10-20% of the original oils. Head, Jones, and Larter (2003) diagram mass loss increasing from essentially zero for conventional oil to something more than 50% for heavy oils, which of themselves are subject to no more than 20% loss. Accompanying the mass loss is a decrease in API gravity from 36° to 5-20°; decrease in gas/oil ratio from 0.17 kg gas/kg oil; decrease in gas liquids from 20% to 2%; increase in sulfur from 0.3wt% to 1.5+wt%; and decrease in C15+ saturates from 75% to 35%. This calculation of mass loss shows: (1) the enormous amount of oil initially generated in heavy oil and natural bitumen basins, especially Western Canada Sedimentary and Eastern Venezuela basins; and (2) the huge economic burden imposed by this mass loss on the production-transportation-processing train of the remaining heavy oil and natural bitumen.

Origins of Heavy Oil and Natural Bitumen

It is possible to form heavy oil and natural bitumen by several processes. First, the oil may be expelled from its source rock as immature oil. There is general agreement that immature oils account for a small percentage of the heavy oil (Larter and others, 2006). Most heavy oil and natural bitumen is thought to be expelled from source rocks as light or medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation. In this case, the biodegradation is aerobic. A third proposal is that biodegradation can also occur at depth in subsurface reservoirs (Head, Jones, and Larter, 2003; Larter and others, 2003; Larter and others, 2006). This explanation permits biodegradation to occur in any reservoir that has a water leg and has not been heated to more than 176° F. The controls on the biodegradation depend on local factors rather than basin-wide factors. Because the purpose of this report is to describe the geologic basin setting of the known heavy oil and natural bitumen deposits, it is beyond the scope of this report to argue the source or genesis of heavy oil and natural bitumen for each basin of the world.

Data Sources

Data for heavy oil resource occurrences and quantities for individual oilfields and reservoirs have been compiled from many published reports and commercial data bases. The most important of these include Demaison (1977), IHS Energy Group (2004), NRG Associates (1997), Parsons (1973), Roadifer (1987), Rühl (1982), and the U.S. Department of Energy, National Energy Technology Laboratory (1983, 2005)

Data for natural bitumen deposits in the United States are summarized in U.S Department of Energy, National Energy Technology Laboratory (1991), but information for Utah is taken from Oblad and others (1987) and Ritzma (1979). Although there is no single data source for deposits outside the United States, there is a rich literature, particularly for Russia and the countries of the Former Soviet Union. For Canada, reliance is placed on reports of the Alberta Energy and Utilities Board (2004) and Saskatchewan Industry and Resources (2003).

Resource Estimates

We consider the total original oil in place (OOIP) to be the most useful parameter for describing the location and volume of heavy oil and natural bitumen resources. Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define the resource volumes that could someday be of commercial interest. If only a recoverable volume of heavy oil for the accumulation was published, the discovered OOIP was computed according to the protocol set forth in table 3.

Natural bitumen originally in place is often reported in the literature. Where only a recoverable estimate is published, the in-place volumes were calculated according to the protocols given for heavy oil; this is especially the case for bitumen deposits above 4°API gravity, to which we arbitrarily refer as extra-heavy oil.

Poorly known deposits of heavy oil and natural bitumen are included in the category of prospective additional resources, as described in table 3. In no case are values for prospective additional resource volumes calculated as in the case of discovered resources but were taken directly from the published literature.

Table 4 summarizes the resources and essential physical parameters of the heavy oil and natural bitumen contained in each of the basin types. These characteristics affect heavy oil and natural bitumen occurrence and recovery. Recovery can be primary, as in the case of cold production without gravel packing, if the gas to oil ratio is high enough to provide necessary reservoir energy. Otherwise, recovery generally necessitates the application of enhanced recovery methods, such as thermal energy or the injection of solvents.

Recovery Methods

How the reservoir parameters apply to enhanced recovery is summarized from Taber, Martin, and Seright (1997a, 1997b) in table 5, which covers the most commonly used, or at least attempted enhanced oil recovery (EOR) methods. Of these methods, immiscible gas injection, polymer flooding, and *in situ* combustion (fireflood) have met with limited success for heavy oil and natural bitumen. Steam injection (cyclic steam, huff 'n puff) has been most successful, frequently by use of cyclic steam, followed by steam flooding. Surface mining and cold *in situ* production are usually considered to be primary recovery methods. They can be suited to the extraction of heavy oil and natural bitumen under proper conditions.

Most of the process descriptions which follow are taken from Taber, Martin, and Seright (1997b). Many processes may result in the process agent, such as nitrogen or carbon dioxide, remaining immiscible with the reservoir hydrocarbon or else becoming miscible with it. The miscibility is dependent upon the minimum miscibility pressure (MMP) and determines the way in which the process agent achieves EOR. While this summary discussion shows the breadth of the EOR processes operators have tried and continue to try as experimental projects, thermal EOR methods account for most of the heavy oil that is commercially produced. Data on the frequency of the applications are taken, unless otherwise cited, from the Oil and Gas Journal Historical Review, 1980-2006 (2006), particularly the Oil and Gas Journal 2000 and 2006 EOR Surveys.

Nitrogen gas drive is low in cost and therefore may be used in large amounts. It is commonly used with light oils for miscible recovery. However, it may also be used for an immiscible gas flood. The Oil and Gas Journal 2000 Survey includes one immiscible nitrogen gas drive in a sandstone reservoir with 16˚API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. The Journal's 2006 Survey reports one each heavy oil nitrogen miscible and nitrogen immiscible projects. The miscible project is 19˚API, located in the Bay of Campeche, with 19 wells, but with no report of production capacity. The immiscible project has oil of 16˚API at 4,600 feet in sandstone. For this project total production is reported to be 1,500 b/d of which 1,000 b/d is enhanced by immiscible nitrogen injection.

Of the 77 CO2 projects in the Journal 2000 Survey, 70 are for miscible CO2 and none entails heavy oil. This is true also in the Journal 2006 Survey, where all 86 CO2 projects are devoted to light oil, above 28˚API. In the Journal 2000 Survey, five of the seven immiscible CO2 projects are applied to heavy oil reservoirs, four in clastics and one in limestone. The latter, in the West Raman field in Turkey, involves oil of 13°API, lies at 4,265 feet, and produces 8,000 b/d. The reservoir contains nearly two billion barrels of original oil in place. Recoverable reserves remain low because of the recalcitrance of the reservoir. Steam flooding has been unsuccessful. By the date of the Journal 2006, there are eight immiscible CO2 projects, with five of them entailing heavy oil amounting to 7,174 b/d. The two largest projects are light oil and heavy oil and are each in carbonate reservoirs.

Polymer/chemical flooding includes micellar/polymer, alkaline-surfactant-polymer (ASP), and alkaline fluids (Taber, Martin, and Seright, 1997a, 1997b). Recovery is complex, leading to the lowering of interfacial tension between oil and water, solubilization of oil in some micellar systems, emulsification of oil and water, wettability alteration, and enhancement of mobility. Limitations and costs indicate for these floods the desirability of clean clastic formations. The Journal 2000 Survey shows five heavy oil polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 feet. They were producing about 366 b/d and the projects were deemed successful or promising. Projects such as these are below the desirable gravity limits and are more viscous than desired at 45 cP.

Polymer floods improve recovery over untreated water flood by increasing the viscosity of the water, decreasing thus the mobility of the water, and contacting a larger volume of the reservoir. The advantages of a polymer flood over a plain water flood are apparent. The Journal 2000 Survey lists 22 polymer flood projects, of which five involve heavy oil. These five are within the range of the polymer screen, although the gravities are marginal, lying from 13.5°API to a bit above 15°API. The five were producing 7,140 b/d, of which 2,120 b/d were attributed to EOR. The Journal 2006 Survey shows 20 polymer floods, with five exploring heavy oil reservoirs. Three of the five are producing 7,140 b/d total oil and 2,120 b/d of enhanced production.

The Journal 2000 Survey shows four hot water floods, one of which is heavy oil with a gravity of 12°API, viscosity of 900 cP, and starting saturation of only 15 percent. Project production was 300 b/d. Two of three hot water floods included in the Journal 2006 Survey are intended to enhance production of heavy oil. The two yield about 1,700 b/d of total oil and 1,700 b/d of enhanced hot water flood oil.

In situ combustion (fire flood) is theoretically simple, setting the reservoir oil on fire and sustaining the burn by the injection of air. Usually, the air is introduced through an injector well and the combustion front moves toward to the production wells. A variant is to include a water flood with the fire, the result being forward combustion with a water flood. Another variant is to begin a fire flood, then convert the initial well to a producer and inject air from adjacent wells. The problem with this reverse combustion is that it doesn't appear to work.

In situ combustion leads to oil recovery by the introduction of heat from the burning front, which leads to reduction in viscosity. Further, the products of steam distillation and thermal cracking of the reservoir oil are carried forward to upgrade the remaining oil. An advantage of the process is that the coke formed by the heat itself burns to supply heat. Lastly, the injected air adds to the reservoir pressure. The burning of the coke sustains the process so that the process would not work with light oil deficient in asphaltic components. The process entails a number of problems, some severe, but the Journal 2000 Survey shows 14 combustion projects, of which five are light oil and the remaining nine are heavy, between 13.5°API and 19°API. Viscosities and starting oil saturations are relatively high. It is notable that the heavy oil projects are in sandstones and the light oil in carbonates. The heavy oil *in situ* combustion projects were producing about 7,000 b/d. The Journal 2006 Survey includes nine heavy oil combustion projects among a total of twenty-one. The heavy oil projects yield about 7,000 b/d of combustion-enhanced oil, which ranges from 13.5˚API to 19˚API.

Steam injection for EOR recovery is done in two ways, either by cyclic steam injection (huff 'n puff) or continuous steam flood. Projects are frequently begun as cyclic steam, whereby a high quality steam is injected and soaks the reservoir for a period, and the oil, with lowered viscosity from the heat, is then produced through the injection well. Such soak cycles may be repeated up to six times, following which a steam flood is initiated. In general, steam projects are best suited to clastic reservoirs at depths no greater than about 4,000 feet, and with reservoir thicknesses greater than 20 feet and oil saturations above 40% of pore volume. For reservoirs of greater depth the steam is lowered in quality through heat loss to the well bore to where the project becomes a hot water flood. Steam is seldom applied to carbonate reservoirs in large part due to heat loss in fractures.

The Journal 2000 Survey lists 172 steam drive projects. Of these, four in Canada give no gravity reading, thirteen are medium oil from 22°API to 25°API, and the rest are heavy oil. The largest of all is at Duri field in Indonesia and this oil is 22°API. For the project list as a whole, the average gravity is 14°API, with a maximum value of 30°API and a minimum of 4°API. The average viscosity is 37,500 cP, with maximum and minimum values of 5,000,000 cP and 6 cP. Oil saturations range from 35% to 90%, the average being 68%. Most importantly, production from the project areas was 1.4 million b/d and of this, 1.3 million b/d was from steam drive EOR.

All but three of the 120 steam projects found in the Journal 2006 Survey entail recovery of heavy oil. The oil averages 12.9˚API, with a low value of 8˚API and a high of 28˚API (one of the three light oil reservoirs). The viscosity averages 58,000 cP, with a high value of 5 million cP and a low of 2 cP. The projects are yielding over 1.3 million b/d, virtually all being steam EOR.

Maps

The geographic distribution of basins reporting heavy oil and natural bitumen, as identified by their Klemme basin types, appears on Plate 1. A diagram of the Klemme basin classification illustrates the architectural form and the geological basin structure by type. This plate also includes histograms of the total original oil in place resource volumes of both heavy oil and natural bitumen. Plates 2 and 3, respectively, depict the worldwide distribution of heavy oil and natural bitumen resources originally in place. Each map classifies basins by the reported volumes of total original oil in place. A table ranks the basins by total original oil in place volumes besides indicating Klemme basin type and reporting discovered original oil in place and prospective additional oil in place. Plates 2 and 3 also include an inset map of the geographic distribution of original heavy oil or natural bitumen by 10 world regions (see table 6 for regional listing of countries reporting heavy oil or natural bitumen.)

Basin outlines of the sedimentary provinces are digitally reproduced from the AAPG base map compiled by St. John (1996). The basin outlines of St. John (1996) are unaltered. However, the reader should note that the basin outlines are considered to be generalizations useful for displaying the resource distributions but are less than reliable as a regional mapping tool. Also, some basin names have been changed to names more commonly used by geologists in the local country. These equivalent names and the original names from Bally (1984) and St. John (1996) are detailed in table 1-1 in Appendix 1. The basin outline for Eastern Venezuela as shown does not include the island of Trinidad where both heavy oil and natural bitumen resources occur. For this report, resources from Trinidad and Tobago are reported in the Eastern Venezuela basin totals. In a few cases a single basin as outlined on the plates is composed of multiple basins to provide more meaningful local information. This is particularly true in the United States, where the AAPG-CSD map was employed (Meyer, Wallace, and Wagner, 1991). In each case, the individual basins retain the same basin type as the basin shown on the map and all such basins are identified in Appendix 1.

Basins having heavy oil or natural bitumen deposits are listed in table 2-1 in Appendix 2 along with the Klemme basin type, countries and U.S. states or Canadian provinces reporting deposits and other names cited in literature. The Klemme basin classification diagram in Plate 1 is reprinted in fig. 3-1 in Appendix 3 for the reader's convenience. The tables from Plates 2 and 3 are reprinted as table 4-1 and table 4-2 for the reader's convenience.

Klemme Basin Classification

Many classifications of petroleum basins have been prepared. In one of the earliest, Kay (1951) outlined the basic architecture of geosynclines, with suggestions as to their origins. Kay's work preceded the later theory of plate tectonics. Klemme (1977, 1980a, 1980b, 1983, 1984) gives a summary description of petroleum basins together with their classification, based upon basin origin and inherent geological characteristics. This classification is simple and readily applicable to the understanding of heavy oil and natural bitumen occurrence. The Klemme basin types assigned to the heavy oil and natural bitumen basins described in this report correspond to the assignments made in St. John, Bally, and Klemme (1984). In some cases of multiple type designations in St. John, Bally, and Klemme (1984) a unique type designation was resolved by reference to Bally (1984) or Bally and Snelson (1980). Only a few of the basins originally designated as multiple types in St. John, Bally and Klemme (1984) appear to contain heavy oil and natural bitumen.

Table 7 summarizes the criteria upon which Klemme based his classification. The general description of the resource endowment associated to the Klemme basin classification is based upon oilfield (and gasfield) data of the world as of 1980 without regard to the density or other chemical attributes of the hydrocarbons they contain (Klemme, 1984). At the time of Klemme's work, the average density U.S. refinery crude oil was about 33.7°API (Swain, 1991). A decline in the average to about 30.6°API by 2003 perhaps signifies the increasing importance of heavy oil in the mix (Swain, 2005).

Generally, basins may be described as large or small and linear or circular in shape. They may also be described by the ratio of surface area to sedimentary volume. The basement profile or basin cross-section, together with the physical description, permits the interpretation of the fundamental basin architecture. The basin can then be placed within the relevant plate tectonic framework and assigned to one of four basin types, of which two have sub-types. A diagram of the Klemme basin types appears on Plate 1, color-coded to the basins on the map.

In the following section we provide descriptions of the basin types from Klemme (1980b, 1983, 1984) followed by discussion of the heavy oil and natural bitumen occurrences within those same basin types, summary data for which are given in table 4. Because most heavy oil and natural bitumen deposits have resulted from the alteration of conventional and medium oil, the factors leading to the initial conventional and medium oil accumulations are relevant to the subsequent occurrence of heavy oil and natural bitumen.

Type I. Interior Craton Basins

The sediment load in these basins is somewhat more clastic than carbonate. Reservoir recoveries are low and few of the basins contain giant fields. Traps are generally related to central arches, such as the Cincinnati arch, treated here as a separate province (Plates 1-3), or the arches of the Siberian platform (see below for further explanation). Traps also are found in smaller basins over the craton, such as the Michigan basin. The origin of these depressions is unclear although most of them began during the Precambrian (Klemme, 1980a, 1980b).

The six Type I basins having heavy oil contain less than 3 billion barrels of oil in place and of this 93% occurs in the Illinois basin alone. Four Type I basins that contain natural bitumen have 60 billion barrels of natural bitumen in place, with nearly 99% in the Tunguska basin in eastern Siberia and the rest in the Illinois basin. The Tunguska basin covers most of the Siberian platform, around the borders of which are found cratonic margin basins of Type IIA. For convenience all the resource is assigned to the Tunguska basin. The prospective additional resource of 52 billion barrels is almost certainly an absolute minimum value for this potentially valuable but difficult to access area (Meyer and Freeman, 2006.)

Type II. Continental Multicyclic Basins

Type IIA. Craton margin (composite)

These basins, formed on continental cratonic margins, are generally linear, asymmetrical in profile, usually beginning as extensional platforms or sags and ending as compressional foredeeps. Therefore they are multicyclic basins featuring a high ratio of sediment volume to surface area. Traps are mainly large arches or block uplifts and may be found in rocks of either the lower (platform) or upper (compression) tectonic cycle. About 14% of conventional oil discovered in the world by 1980 is from marginal cratonic basins (Klemme, 1980a, 1980b).

Type IIA basins are of moderate importance with respect to heavy oil, with about 158 billion barrels of oil in place distributed among 28 basins. Three Type IIA basins, the Western Canada Sedimentary, Putumayo, and Volga-Ural, have combined total heavy oil resource of 123 billion barrels of oil in place, or 78% of the total for Type IIA basins.

In comparison, natural bitumen in 24 Type IIA basins accounts for 2,623 billion barrels of natural bitumen in place, or nearly 48% of the world natural bitumen total. The Western Canada Sedimentary basin accounts for 2,334 billion barrels of natural bitumen in place, or about 89%. Of the Canadian total, 703 billion barrels of natural bitumen in place is prospective additional oil, largely confined to the deeply buried bitumen in the carbonate that underlie the Peace River and part of the Athabasca oil sand deposit in an area known as the Carbonate Triangle. The significance of the Canadian deposits lies in their concentration in a few major deposits: Athabasca, from which the reservoir is exploited at or near the surface and shallow subsurface, and Cold Lake and Peace River, from which the bitumen is extracted from the subsurface. Two other basins contain much less but still significant amounts of natural bitumen, the Volga-Ural basin in Russia (263 billion barrels of natural bitumen in place) and the Uinta basin in the United States (12 billion barrels of natural bitumen in place). The Volga-Ural deposits are numerous, but individually are small and mostly of local interest. The Uinta deposits are much more concentrated aerially, but are found in difficult terrain remote from established transportation and refining facilities.

Type IIB. Craton accreted margin (complex)

These basins are complex continental sags on the accreted margins of cratons. Architecturally, they are similar to Type IIA basins, but begin with rifting rather than sags. About three-quarters of Type IIA and IIB basins have proven productive, and they contain approximately one-fourth of the world's total oil and gas (Klemme, 1980a, 1980b).

The 13 Type IIB basins contain a moderate amount of heavy oil (193 billion barrels of oil in place). The two most significant basins are in Russia, West Siberia and Timan-Pechora. These, together with most of the other Type IIB heavy oil basins, are of far greater importance for their conventional and medium oil resources.

Five Type IIB basins hold 29 billion barrels of natural bitumen in place. Only the Timan-Pechora basin contains significant natural bitumen deposits, about 22 billion barrels of natural bitumen in place. Unfortunately, this resource is distributed among a large number of generally small deposits.

Type IIC. Crustal collision zone (convergent plate margin)

These basins are found at the crustal collision zone along convergent plate margins, where they are downwarped into small ocean basins. Although they are compressional in final form, as elongate and asymmetrical foredeeps, they begin as sags or platforms early in the tectonic cycle. Type IIC downwarp basins encompass only about 18 percent of world basin area, but contain nearly one-half of the world's total oil and gas. These basins are subdivided into three subtypes, depending on their ultimate deformation or lack thereof: Type IICa, closed; Type IICb, trough; and Type IICc, open (Klemme, 1980a, 1980b).

Although basins of this type begin as downwarps that opened into small ocean basins (Type IICc), they may become closed (Type IICa) as a result of the collision of continental plates. Upon closing, a large, linear, asymmetric basin with sources from two sides is formed, resembling a Type IIA basin. Further plate movement appears to destroy much of the closed basin, leaving a narrow, sinuous foredeep, that is, a Type IICb trough. Relatively high hydrocarbon endowments in the open and the closed types may be related to above-normal geothermal gradients, which accentuates hydrocarbon maturation and long-distance ramp migration. Traps are mostly anticlinal, either draping over arches or compressional folds, and are commonly related to salt flowage.

Type IICa basins, with their architectural similarity to Type IIA basins, are the most important of the three Type IIC heavy oil basins. The 15 basins account for 1,610 billion barrels of the heavy oil in place, with the Arabian, Eastern Venezuela, and Zagros basins containing 95% of the total. Of particular interest is the Eastern Venezuela basin which includes large accumulations of conventional and medium oil, while at the same time possessing an immense resource of both heavy oil and natural bitumen.

Type IICa basins also are rich in natural bitumen, with a total of 2,507 billion barrels of natural bitumen in place among the six. About 83% of this occurs in Venezuela, mostly in the southern part of the Eastern Venezuelan basin known as the Orinoco Oil Belt. Here the reservoir rocks impinge upon the

Guyana craton in much the same fashion as the reservoir rocks of the Western Canada Sedimentary basin lap onto the Canadian shield. The only other significant Type IICa accumulation of natural bitumen is found in the North Caspian basin (421 billion barrels of natural bitumen in place).

Fourteen Type IICb basins contain modest amounts of heavy oil (32 billion barrels of oil in place) and even less of natural bitumen (5 billion barrels of natural bitumen in place in seven basins). Much of this resource is found in the Caltanisetta and Durres basins, on either side of the Adriatic Sea. Durres basin resources are aggregated with the South Adriatic and the province is labeled South Adriatic on the plates. Significant amounts of the Caltanisetta resource occurs offshore.

The amount of heavy oil in the 12 Type IICc basins is substantial (460 billion barrels of oil in place). The Campeche, by far the largest, and Tampico basins in Mexico and the North Slope basin in the United States account for 89% of the heavy oil. The Campeche field, which is actually an assemblage of closely associated fields, is found about 65 miles offshore of the Yucatan Peninsula in the Gulf of Mexico. The North Slope basin, on the north coast of Alaska, occurs in an area of harsh climate and permafrost, which makes heavy oil and natural bitumen recovery by the application of thermal (steam) methods difficult both physically and environmentally. The U.S. fields in the East Texas, Gulf Coast, and Mississippi Salt Dome basins account for only 5% of the heavy oil in basins of this type.

Only a small amount of natural bitumen (24 billion barrels) has been discovered in eight Type IICc basins. Two of these, the North Slope and South Texas Salt Dome basins, are significant for possible future development.

Type III. Continental Rifted Basins

Type IIIA. Craton and accreted zone (rift)

These are small, linear continental basins, irregular in profile, which formed by rifting and simultaneous sagging in the craton and along the accreted continental margin. About two-thirds of them are formed along the trend of older deformation belts and one-third are developed upon Precambrian shields. Rifts are extensional and lead to block movements so that traps are typically combinations. Oil migration was often lateral, over short distances. Rift basins are few, about five percent of the world's basins, but half of them are productive. Because of their high recovery factors, Type IIIA basins accounted for 10% of the world's total recoverable oil and gas in 1980 (Klemme, 1980a, 1980b).

Globally, there are 28 Type IIIA heavy oil basins, containing 222 billion barrels of oil in place The Bohai Gulf basin in China accounts for 63% of the heavy oil, with an additional 11% derived from the Gulf of Suez and 10% from the Northern North Sea. Outside of these, most Type IIIA basins contain just a few deposits. The five basins in Type IIIA have almost 22 billion barrels of natural bitumen in place, but half of that is located in the Northern North Sea basin.

Type IIIB. Rifted convergent margin (oceanic consumption)

Type IIIBa basins are classified as back-arc basins on the convergent cratonic side of volcanic arcs. They are small, linear basins with irregular profiles (Klemme, 1980a, 1980b).

Not unlike Type IIIA basins, the volume of heavy oil found in the Type IIIBa basins is small. Seventeen heavy oil basins contain 49 billion barrels of oil in place and 83% of this amount is in Central Sumatra.

Just 4 billion barrels of natural bitumen in place are identified in the Type IIIA basin called Bone Gulf. Small amounts are also known to occur in the Cook Inlet and Tonga basins.

Type IIIBb basins are associated with rifted, convergent cratonic margins where wrench faulting and subduction have destroyed the island arc. They are small, linear, and irregular in profile.

The 14 Type IIIBb basins containing heavy oil account for only 134 billion barrels of oil in place. These basins are only moderately important on a global scale, but have been very important to the California oil industry. The seven such basins of California - Central Coastal, Channel Islands, Los Angeles, Sacramento, San Joaquin, Santa Maria, and Ventura – equal 129 billion barrels of oil in place or 96%.

There are nine Type IIIBb basins that report natural bitumen deposits. They contain 4 billion barrels of natural bitumen in place, about half of which is in the Santa Maria basin.

Types IIIBa and IIIBb basins comprise about seven percent of world basin area, but only one-quarter of the basins are productive for oil of all types. However, the productive ones, which represent only two percent of world basin area, yield about seven percent of total world's oil and gas (Klemme, 1983). Some of these productive basins, particularly those located in California, have high reservoir recovery factors.

Type IIIBc basins are small and elongate, irregular in profile, and occupy a median zone either between an oceanic subduction zone and the craton or in the collision zone between two cratonic plates. They result from median zone wrench faulting and consequent rifts. Such basins make up about three and one-half percent of world basin area and contribute two and one-half percent of total world oil and gas.

Type IIIBc basins are important to the occurrence of heavy oil (351 billion barrels of oil in place). Although there are nine basins of this type, 92% of the heavy oil is concentrated in the Maracaibo basin. The Maracaibo basin also yields 95% of the 178 billion barrels of natural bitumen in place in the five basins containing this type of oil. This makes the Maracaibo basin unique: no other basin type is so completely dominated by a single basin.

Type IIIC. Rifted passive margin (divergence)

These basins, often aptly called pull-apart basins, are extensional, elongate, and asymmetric. Located along major oceanic boundaries of spreading plates, they are divergent and occupy the intermediate zone between thick continental crust and thin oceanic crust. They appear to begin with a rifting stage, making possible the later sedimentary fill from the continent. Type IIIC basins, comprising 18 percent of the world's basin area, are mostly offshore and are often in water as deep as 5,000 feet. For this reason their development has been slow but is accelerating as traditional, easily accessible basins reach full development and world demand for petroleum increases (Klemme, 1980a, 1980b).

Twenty-eight Type IIIC basins yield 158 billion barrels of heavy oil in place, but one, the offshore Campos basin, contains 66% of this heavy oil. These continental margin basins must at some point in their histories have been sufficiently elevated to permit their generated conventional oil to be degraded. It is possible that the heavy oil could be very immature, having undergone only primary migration and later elevation. The geologic history of such basins does not encourage this view. However, the oil could well have been degraded bacterially at depth according to the recently proposed mechanisms suggested by Head, Jones, and Larter (2003) and Larter and others (2006). In a pull-apart basin the sediments would have accumulated rapidly and at depth, the expressed oil then was subject to degradation. The problem with degradation at depth is the loss of mobility unless it can be demonstrated that the oil was never elevated and, in fact, the Campos basin oil is deep, occurring at an average depth of nearly 8,400 feet.

The bitumen resource in Type IIIC basins is small (47 billion barrels of natural bitumen in place in seven basins), as are nearly all bitumen occurrences in comparison with the Western Canada Sedimentary and Eastern Venezuela basins. But the 38.3 billion barrels of natural bitumen in place in the Ghana basin of southwestern Nigeria is exploitable and the amount of the resource may be understated. Like many bitumen deposits it awaits more detailed evaluation.

Type IV. Delta (Tertiary to recent)

Deltas form along continental margins as extensional sags, are circular to elongate, and show an extremely high ratio of sediment fill to surface area. Architecturally, they are modified sags comprised of sediment depocenters and occur along both divergent and convergent cratonic margins. Although by 1980 delta basins provide two and one-half percent of world basin area and perhaps six percent of total oil and gas (Klemme, 1980a, 1980b), they account for more of the conventional resource endowment with the recent successful exploration in frontier deep water areas.

The three Type IV delta basins produce scant heavy oil (37 billion barrels of oil in place) and no natural bitumen. This is related to the extremely high ratio of sediment fill to surface area and that these basins exhibited rapid burial of the source organic matter. Burial is constant and uninterrupted, providing very limited opportunity for degradation of the generated petroleum.

Type V. Fore-Arc Basins

Fore-arc basins are located on the ocean side of volcanic arcs. They result from both extension and compression, are elongate and asymmetrical in profile, and architecturally are the result of subduction. Fore-arc basins are few in number and generally not very productive (Klemme, 1980a, 1980b).

Very small amounts of heavy oil are found in the Barbados basin. Although a natural bitumen deposit is reported in the Shumagin basin, volume estimates are not available.

Essentially no heavy oil or natural bitumen is found in fore-arc basins because these basins do not generate large quantities of petroleum of any type and therefore provide relatively little material to be degraded.

Regional Distribution of Heavy Oil and Natural Bitumen

The preceding discussion has been concerned with the distribution of heavy oil and natural bitumen in the world's geological basins. This is of paramount interest in the exploration for the two commodities and for their exploitation. The chemical and physical attributes of the fluids and the reservoirs which contain them do not respect political boundaries.

At the same time it is necessary to understand the geography of the heavy oil and natural bitumen for both economic and political reasons. These factors will be dealt with in detail in a subsequent report. The bar graphs on Plates 2 and 3 give the regional distribution of total and discovered original oil in-place for heavy oil and natural bitumen, respectively. The distribution of the resources is given in table 8. The western hemisphere accounts for about 52 percent of the world's heavy oil and more than 85 percent of its natural bitumen. The Middle East and South America have the largest in-place volumes of heavy oil, followed by North America. North and South America have, by far, the largest in-place volumes of natural bitumen. Very large resource deposits are also known in eastern Siberia but insufficient data are available to make more than nominal size estimates.

Summary

From the preceding basin discussion, Klemme basin Type IICa is by far the most prolific in terms of heavy oil. For natural bitumen Klemme basin Type IIA and Type IICa are the most prolific. The basin types involved are architecturally analogous, beginning with depositional platforms or sags and ending up as foredeeps. They differ only in their modes of origin. What they have in common is truncation against cratonic masses updip from rich source areas. This situation permitted immense accumulations of conventional oil at shallow depths, with near ideal conditions for oil entrapment and biodegradation resulting in formation of heavy oil and bitumen accumulations. The prospective resources from the prospective additional resource deposits in these basins are larger than the discovered resources of many basin types.

The Klemme basin classification system includes elements of basin development and architecture that control basin type. The observed pattern of the heavy oil and natural bitumen occurrences across basin types is consistent with the formation of heavy oil and natural bitumen through the process of degradation of conventional oil. Only relatively small quantities of heavy oil were found in the Interior Craton (Type I), Deltas (Type IV) and Fore-Arc basins (Type V).

Type IICa basins, including the Arabian, Eastern Venezuela, and Zagros, have the largest endowments of heavy oil and also contain the largest amounts of conventional oil. Large volumes of heavy oil are also found in both Type IICc basins, notably, the Campeche, Tampico, and North Slope basins, and in Type IIIBc basins, primarily Maracaibo basin. For natural bitumen, the Western Canada Sedimentary and Eastern Venezuela basins have similar development histories and basin architectural features. Some basin development patterns promote the formation of greater volumes of heavy oil and natural bitumen than others. This is seen most clearly in present occurrences of heavy oil and natural bitumen in the Type IICa and Type IICc basins, with their rich source areas for oil generation and up-dip migration paths to entrapment against cratons. Conventional oil may easily migrate through the tilted platforms until the platforms are breached at or near surface permitting deveopment of asphaltic seals.

Acknowledgments

We gratefully acknowledge critical reviews of the manuscript by James Coleman and Robert Milici, U.S. Geological Survey, and Dale Leckie and Geoff Ryder, Nexen Inc. We are in debt to Dorothy B. Vitaliano and Nora Tamberg, U.S. Geological Survey, Retired, for translations of Russian literature into English.

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Tables 1–8

Table 1. Some chemical and physical attributes of crude oils (averages).

[cP, centipoise; wt%, weight percent; mgKOH/g, milligrams of potassium hydroxide per gram of sample; sp gr, specific gravity; vol%, volume percent; ppm, parts per million; Concarbon, Conradson carbon; VOC, volatile organic compounds; BTEX, benzene, toluene, ethylbenzene, and xylenes]

Attribute	Unit	Conventional oil (131 basins, 8148 deposits)	Medium oil (74 basins, 774 deposits)	Heavy oil (127 basins, 1199 deposits)	Natural bitumen (50 basins, 305 deposits)
API gravity	degrees	38.1	22.4	16.3	5.4
Depth	feet	5,139.60	3,280.20	3,250.00	1,223.80
Viscosity (77°F)	cP	13.7	34	100,947.00	1,290,254.10
Viscosity (100°F)	cP	10.1	64.6	641.7	198,061.40
Viscosity (130°F)	cP	15.7	34.8	278.3	2,371.60
Conradson Carbon	wt%	1.8	5.2	8	13.7
Coke	wt%	2.9	8.2	13	23.7
Asphalt	wt%	8.9	25.1	38.8	67
Carbon	wt%	85.3	83.2	85.1	82.1
Hydrogen	wt%	12.1	11.7	11.4	10.3
Nitrogen	wt%	0.1	0.2	0.4	0.6
Oxygen	wt%	1.2		1.6	2.5
Sulfur	wt%	0.4	1.6	2.9	4.4
Reid vapor pressure	psi	5.2	2.6	2.2	
Flash point	°F	17	20.1	70.5	
Acid number	mgKOH/g	0.4	1.2	2	3
Pour point	°F	16.3	8.6	19.7	72.9
C1-C4	vol%	2.8	0.8	0.6	
Gasoline + naphtha	vol%	31.5	11.1	6.8	4.4
Gasoline + naphtha	sp gr	0.76	0.769	0.773	0.798
Residuum	vol%	22.1	39.8	52.8	62.2
Residuum	sp gr	0.944	1.005	1.104	1.079
Asphaltenes	wt%	2.5	6.5	12.7	26.1
Asphaltenes + resins	wt%	10.9	28.5	35.6	49.2
Aluminum	ppm	1.174	1.906	236.021	21,040.03
Copper	ppm	0.439	0.569	3.965	44.884
Iron	ppm	6.443	16.588	371.05	4,292.96
Mercury	ppm	19.312	15	8.74	0.019
Nickel	ppm	8.023	32.912	59.106	89.137
Lead	ppm	0.933	1.548	1.159	4.758
Titanium	ppm	0.289	0.465	8.025	493.129
Vanadium	ppm	16.214	98.433	177.365	334.428
Residue Concarbon	wt%	6.5	11.2	14	19
Residue Nitrogen	wt%	0.174	0.304	0.968	0.75
Residue Nickel	ppm	25.7	43.8	104.3	
Residue Sulfur	ppm	1.5	3.2	3.9	
Residue Vanadium	ppm	43.2	173.7	528.9	532
Residue viscosity (122°F)	cP	1,435.80	4,564.30	23,139.80	
Total BTEX volatiles	ppm	10,011.40	5,014.40	2,708.00	
Total VOC volatiles	ppm	15,996.30	8,209.20	4,891.10	

Table 2. Conversion factors and equivalences applied to standardize data.

Standard unit in this report	Units as reported in literaure	Formula
	API gravity	
°API (degrees)	specific gravity (sp gr), (g/cm^3)	= (141.5/(sp gr))-131.5
	Area	
acre	square mile (mi^2)	= (1/640) mi^2
	square kilometer (km^2)	= 0.00405 km^2
	hectare (ha)	= 0.405 ha
	Asphalt in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 4.9× (CCR)
	Barrels of oil	
barrel (bbl), (petroleum, 1 barrel=42 gal)	cubic meter (m^3)	= 0.159 m^3
	metric tonne (t)	= 0.159× (sp gr) ×t
	Coke in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 1.6× (CCR)
	Gas-oil ratio	
cubic feet gas/barrel oil (ft^3 gas/bbl oil)	cubic meters gas/cubic meter oil (m^3 gas/m^3 oil)	= 0.18× (m^3gas/m^3oil)
	Parts per million	
parts per million (ppm)	gram/metric tonne (g/t)	= g/t
	milligram/kilogram (mg/kg)	= mg/kg
	microgram/gram (µg/g)	= µg/g
	milligram/gram (mg/g)	= 0.001 mg/g
	weight percent (wt%)	= 0.0001 wt%
	Parts per billion	
parts per billion (ppb)	parts per million (ppm)	= 0.001 ppm
	Permeability	
millidarcy (md)	micrometer squared (μm^2)	= 1,000 μm^2
	Pressure	
pound per square inch (psi)	kilopascal (kPa)	= 6.89 kPA
	megapascal (Mpa)	= 0.00689 MPa
	bar	= 0.0689 bar
	kilograms/square centimeter (kg/cm^2)	= 0.0703 kg/cm^2
	Specific gravity (density)	
specific gravity (sp gr), (g/cm^3)	°API (degrees)	= 141.5/(131.5+°API)
	Temperature	
degrees Fahrenheit (°F)	degrees Celsius (°C)	= (1.8×°C)+32
degrees Celsius (°C)	degrees Fahrenheit (°F)	= 0.556×(°F-32)
	Viscosity (absolute or dynamic)	
centipoise (cP)	Pascal second (Pa·s)	= 0.001 Pa·s
	millipascal second (mPa·s)	= mPa·s

Table 2. Conversion factors and equivalences applied to standardize data.—Continued

Standard unit in this report	Units as reported in literaure	Formula
	Viscosity (absolute or dynamic)—Continued	
centipoise (cP)—cont.	kinematic viscosity[1]: centistroke (cSt), (mm²/sec)	= cSt × (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given density	= (SUS /4.632)× (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given °API	= (SUS /4.632)×(141.5/(131.5+°API))
	Weight percent	
weight percent (wt%)	parts per million (ppm)	= 10,000 ppm

[1] Kinematic viscosity is equal to the dynamic viscosity divided by the density of the fluid, so at 10°API the magnitudes of the two viscosities are equal.

Table 3. Total original in place resource calculation protocol when discovered oil in place is unavailable.

Define—

- OOIP-disc.: Original Oil In Place, discovered
- RF: Recovery factor (%)
- R: Reserves, known
- OR: Reserves, original sometimes called, known recovery, ultimate production if so reported
- AP: Production, annual
- CP: Production, cumulative
- PA: Prospective additional oil in place resource
- TOOIP = Total original oil in place

Calculations are based given data, which always receives priority; CP, AP and PA are never calculated and must be from published sources. (Assume CP, AP, PA are given)—

- R = 20×AP. This assumes a 20-year life or production plan for the viscous oil.
- OR = R+CP
- RF = 0.1 for clastic reservoirs or if no lithology is reported
- RF = 0.05 for carbonate reservoirs
- OOIP-disc. = OR/RF
- TOOIP = OOIP-disc. + PA

Table 4. Heavy oil and natural bitumen resources in billions of barrels of oil (BBO) and average characteristics of heavy oil and natural bitumen by basin type. Average values for gravity, viscosity, depth, thickness permeability are weighted by volume of oil in place discovered in each heavy oil or natural bitumen deposit by basin type; except for API gravity of heavy oil Type I, where because of relatively few deposits and several outlier values, a trimmed weighted mean value is shown.

[Volumes may not add to totals due to independent rounding; BBO, billions of barrels of oil; cP, centipoise]

Basin type	Total original oil in place (BBO)	Discovered oil in place (BBO)	API gravity (degrees)	Viscosity (cP @ 100°F)	Depth (feet)	Thickness (feet)	Porosity (percent)	Permeability (millidarcy)	Temperature (°F)
				Heavy oil					
I………	3	2	15.9	724	1,455	11	15.3	88	122
IIA…….	158	157	16.3	321	4,696	36	22.8	819	102
IIB…….	181	181	17.7	303	3,335	96	27.2	341	82
IICa…...	1,610	1,582	15.5	344	3,286	150	24	242	144
IICb…...	32	32	15.4	318	3,976	161	16.9	2,384	126
IICc…...	460	460	17.8	455	6,472	379	19.6	1,080	159
IIIA……	222	222	16.3	694	4,967	279	24.9	1,316	159
IIIBa…..	49	49	19.2	137	558	838	24.9	2,391	122
IIIBb…..	134	134	15.8	513	2,855	390	31.9	1,180	116
IIIBc…..	351	351	13.5	2,318	4,852	142	20.1	446	145
IIIC……	158	158	17.2	962	7,227	273	25.1	868	159
IV……..	37	37	17.9	-	7,263	1,195	27.9	1,996	155
V………	<1	<1	18	-	1,843	135	30	-	144
All types	3,396	3,366	16	641	4,213	205	23.7	621	134
				Natural bitumen					
I………	60	8		-	20	317	5.5	100	
IIA…….	2,623	1,908	6.8	185,407	223	53	0.4	611	173
IIB…….	29	26	4.5	-		209	13.1	57	113
IICa…...	2,509	2,319	4.4	31,789	806	156	29.8	973	174
IICb…...	5	5	6.8	-	8,414	1,145	4.7	570	181
IICc…...	24	23	5	1,324	3,880	82	32.4	302	263
IIIA……	22	22	8.7	-	4,667	882	30.3	1,373	85
IIIBa…..	4	4	-	-	-	-	-	-	-
IIIBb…..	3	3	6.7	500,659	3,097	586	28.6	2,211	89
IIIBc…..	178	178	9.5	1,322	8,751	52	34	751	139
IIIC……	47	14	7.3	-	900	103	23.1	2,566	117
IV……..	0	0							
V………	0	0							
All types	5,505	4,512	4.9	198,061	1,345	110	17.3	952	158

Table 5. Enhanced oil recovery (EOR) methods for heavy oil showing primary reservoir threshold criteria.

[modified from Taber, Martin, and Seright (1997a,b); cP, centipoises; PV, pore volume; ft, feet; md, millidarcy; °F, degrees Fahrenheit, wt%, weight percent]

Method	Gravity (°API)	Viscosity (cP)	Oil composition	Oil saturation (%PV)	Lithology	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
Immiscible gases									
Immiscible gases[a]	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1,800	Not critical
Enhanced waterflood									
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10[b]	<9,000	>200-140
Thermal/mechanical									
Combus-tion	>10	<5,000	Asphaltic compo-nents	>50	Highly porous sandstone	>10	>50[c]	<11,500	>100
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200[d]	<4500	Not critical
Surface mining	>7	0 cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10[e]	Not critical	>3:1 over-burden: sand ratio	Not critical

[a] Includes immiscible carbon dioxide flood.

[b] >3 md for some carbonate reservoirs if the intent is to sweep only the fracture systems.

[c] Transmissibility > 20md-ft/cP.

[d] Transmissibility > 50md-ft/cP.

[e] See depth.

Table 6. Listing of countries reporting deposits of heavy oil and/or natural bitumen grouped by region. (See inset maps of regional distribution on Plates 2 and 3.)

North America	South America	Europe	Africa	Transcaucasia	Middle East	Russia	South Asia	East Asia	Southeast Asia and Oceania
Canada	Argentina	Albania	Algeria	Azerbaijan	Bahrain	Russia	Bangladesh	China	Australia
Mexico	Barbados	Austria	Angola	Georgia	Iran		India	Japan	Brunei
United States	Bolivia	Belarus	Cameroon	Kazakhstan	Iraq		Pakistan	Taiwan	Indonesia
	Brazil	Bosnia	Chad	Kyrgyzstan	Israel				Malaysia
	Colombia	Bulgaria	Congo (Brazzaville)	Tajikistan	Jordan				Myanmar
	Cuba	Croatia	Democratic Republic of Congo (Kinshasa)	Turkmenistan	Kuwait				Philippines
	Ecuador	Czech Republic	Egypt	Uzbekistan	Neutral Zone				Thailand
	Guatemala	France	Equatorial Guinea		Oman				Tonga
	Peru	Germany	Gabon		Qatar				Vietnam
	Suriname	Greece	Ghana		Saudi Arabia				
	Trinidad & Tobago	Hungary	Libya		Syria				
	Venezuela	Ireland	Madagascar		Turkey				
		Italy	Morocco		Yemen				
		Malta	Nigeria						
		Moldova	Senegal						
		Netherlands	South Africa						
		Norway	Sudan						
		Poland	Tunsia						
		Romania							
		Serbia							
		Slovakia							
		Spain							
		Sweden							
		Switzerland							
		Ukraine							
		United Kingdom							

Table 7. Attributes of Klemme basin types.

[Sources for attributes 1-15 are Klemme (1980a, 1980b, 1984) and attributes 16 and 17 are from this report]

	Type I	Type IIA	Type IIB	Type IICa
	Craton interior	Continental multicycle basins, craton margin	Continental multicycle basins: craton/acreted zone rift-faulted	Continental interior multicycle basins: close collision zone at paleoplate margin
1. Crustal zone	Continental craton	Continental craton	Contnental craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone
2. Tectonic setting	Continenal crust within interior of craton, near or upon Precambrian sheld areas	Continental crust on exterior margin of craton, basins become multicylic ion Paleozoic or Mesozoic when a second cycle of sediments derived from uplife encroaches	Continental crust, or on margin of craton	Convergent margin along collision zone of paleoplates
3. Regional stress	Extensional	1st cycle: extension, 2nd cycle: compression	(1st) extension with rifting, (2nd) extensional sag	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep
4. Basin size, shape	Large, circular to elongate	Moderate to large, circular to elongate	Large, circular	Large, elongate
5. Basin profile	Symmetrical	Asymmetrical	Irregular to asymmetrical	Asymmetrical
6. Sediment ratio[1]	Low	High	High	High
7. Architectural sequence	Sag	1st cycle: platform or sag, 2nd cycle: foredeep	(1st) rift, (2nd) large circular sag	(1st) platform or sag, (2nd) foredeep
8. Special features	Unconformities, regional arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs
9. Basin lithology[2]	Clastic 60%, carbonate 40%	Clastic 75%, carbonate 25%	Clastic 75%, carbonate 25%	Clastic 35%, carbonate 65%
10. Depth of production[3]	Shallow	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 45%, moderate 30%, deep 25%
11. Geothermal gradient	Low	Low	High	High
12. Temperature	Cool	Cool	Cool	High
13. Age	Paleozoic	Paleozoic, Mesozoic	Paleozoic, Mesozoic	Upper Paleozoic, Mesozoic, Tertiary
14. Oil and gas recovery[4]	Low, few giant fields	Average	Generally average	High
15. Traps	Associated with central arches and stratigraphic traps along basin margins	Basement uplifts, mostly arches or blocks	Basement uplifts, mostly combination of structural stratigraphic	Basement uplifts, arches and fault blocks
16. Propensity for heavy oil	Low	Low	Low	High
17. Propensity for natural bitumen	Low	High	Low	High

[1]Sediment ratio: ratio of sediment volume to basin surface area.

[2]Basin lithology: percentages apply to reservoir rocks, not to the basin fill.

[3]Depth of production: shallow, 0-6000 ft.; medium, 6000-9000 ft.; deep, >9000 ft.

[4]Oil and gas recovery (barrels of oil equivalent per cubic mile of sediment): low, <60,000; average, >=60,000 but <300,000; high, >=300,000.

[5]Does not add to 100% in source, Klemme (1980a,b).

Table 7. Attributes of Klemme basin types.—Continued

	Type IICb	Type IICc	Type IIIA	Type IIIBa
	Continental interior multicycle basins: foredeep portion of collision zone at paleoplate margin	**Continental interior multicycle basins: open collision zone at paleoplate margin**	**Continental rifted basins: craton/accreted zone, rift-faulted, with small linear sag**	**Continental rifted basins: back arc rift-faulted convergent margin**
1. Crustal zone	Ocean crust early stages then continental crust of craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone	Continental craton and accreted zone	Contintental accreted zone with oceanic crust in early stages
2. Tectonic setting	Convergent margin along collision zone of paleoplates, but retain only proximal or foredeep portion of original sediment suite	Convergent margin along collision zone of paleoplates	Continental, on margin of craton. About two-thirds of Type IIIA basins form along trend of older deformation; remainder on Precambrian shields	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages
3. Regional stress	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) extension with local wrench faulting during rifting, (2nd) sag	(1st) extension with local wrench faulting compression, (2nd) extension and compression
4. Basin size, shape	Large, elongate	Large, elongate	Small to moderate, fault controlled, elongate	Small, elongate
5. Basin profile	Asymmetrical	Asymmetrical	Irregular	Irregular
6. Sediment ratio[1]	High	High	High	High but variable
7. Architectural sequence	(1st) platform or sag, (2nd) foredeep	(1st) platform or sag, (2nd) foredeep	(1st) extension with local wrench faulting druing rifting, (2nd) sag	Rift faulting leading to linear sag, may be followd by wrench faulting
8. Special features	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs, unconformities	Large traps, evaporite caps, unconformities, regional source seal	Large traps, and unconformities
9. Basin lithology[2]	Clastic 50%, carbonate 50%	Clastic 35%, carbonate 65%	Clastic 60%, carbonate 40%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 45%, moderate 30%, deep 25%	Shallow 45%, moderate 30%, deep 25%	Moderate 55%, shallow 30%, deep 15%	Shallow 70%, moderate 20%, deep 10%
11. Geothermal gradient	High	High	High	High
12. Temperature	High	High	Normal to high	Normal to high
13. Age	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Paleogene, Neogene	Upper Mesozoic, Paleogene and Neogene
14. Oil and gas recovery[4]	Generally low	High	Generally high	Variable
15. Traps	Basement uplifts, arches and fault blocks	Basement uplifts, arches and fault blocks	Basement uplifts, combination structural/stratigraphic; result in fault block movement	Basement uplifts, fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Moderate	Low
17. Propensity for natural bitumen	Low	Low	Low	Low

Table 7. Attributes of Klemme basin types.—Continued

	Type IIIBb	Type IIIBc	Type IIIC	Type IV	Type V
	Continental rifted basins: transverse rift-faulted convergent margin	**Continental rifted basins: median rift-faulted convengent margin**	**Continental rifted basins: rift-faulted divergent margin, may be subdivided into (a) parallel, or (b) transverse basins**	**Deltas**	**Fore-arc basins**
1. Crustal zone	Contintental accreted zone with oceanic crust in early stages	Contintental accreted zone with oceanic crust in early stages	Ocean crust in early stage, then continental crust of craton and accreted zone	Ocean crust in early stage, then continental crust of craton and accreted zone	Continetal accreted crust and oceanic crust
2. Tectonic setting	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Rift faulting along a divergent, passive or pull-apart continental margin	Almost any location: divergent and convergent margins along open or confined coastal areas	Fore-arc basins located on oceanward side of the volcanic arc in subduction or consumption zone
3. Regional stress	(1st) extension and wrench compression, (2nd) extension and compression	(1st) extension and wrench compression, (2nd) extension and compression	Extension leading to rift or wrench faulting	Extension as sag develops but uncertain as to the initial cause of sag, roots being deeply buried	Compression and extension
4. Basin size, shape	Small, elongate	Small, elongate	Small to moderate, elongate	Moderate, circular to elongate	Small, elongate
5. Basin profile	Irregular	Irregular	Asymmetrical	Depocenter	Asymmetrical
6. Sediment ratio[1]	High but variable	High but variable	High	Extremely high	High
7. Architectural sequence	Rift faulting leading to linear sag, may be followd by wrench faulting	Rift faulting leading to linear sag, may be followd by wrench faulting	Linear sage with irregular profile	Roots of deltas deeply buried; extension leads to half-sag with sedimentary fill thickening seaward.	Small linear troughs
8. Special features	Large traps, and unconformities	Large traps, unconformities, and regional arches	Possible unconformities and regional source seals	None	Large traps, and unconformities
9. Basin lithology[2]	Clastic 90%, carbonate 10%	Clastic 90%, carbonate 10%	Clastic 70%, carbonate 30%	Clastic 100%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 70%, moderate 20%, deep 10%	Shallow 70%, moderate 20%, deep 10%	Deep 60%, moderate 30%, shallow 10%	Deep 65%, moderate 30%, shallow 5%	Shallow 70%, deep 20%, moderate 10%
11. Geothermal gradient	High	Normal to high	Low	Low	High
12. Temperature	Normal to high	Normal to high	Cool	Normal to low	High to normal
13. Age	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Paleogene, Neogene, and Quaternary	Upper Mesozoic, Tertiary
14. Oil and gas recovery[4]	Variable	Variable	Low	High	High but variable
15. Traps	Basement uplifts, fault blocks and combination	Basement uplifts, fault blocks and combination	Fault blocks and combination	Primarily tensional growth (roll-over) anticlines and flowage: basement not involved	Fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Low	Low	Nil
17. Propensity for natural bitumen	Low	Low	Low	Nil	Nil

Table 8. Regional distribution of heavy oil and natural bitumen (billion barrels).

[Volumes may not add to totals due to independent rounding]

Region[1]	Discovered orginal oil in place	Prospective additional	Total original oil in place
	Heavy oil		
North America…………………	650	2	651
South America…………………	1099	28	1127
Europe………………………….	75	0	75
Africa…………………………..	83	0	83
Transcaucasia…………………..	52	0	52
Middle East…………………….	971	0	971
Russia…………………………..	182	0	182
South Asia……………………...	18	0	18
East Asia……………………….	168	0	168
Southeast Asia and Oceania……	68	0	68
Total………………………..	3366	29	3396
	Natural bitumen		
North America…………………	1671	720	2391
South America…………………	2070	190	2260
Europe………………………….	17	0	17
Africa…………………………..	13	33	46
Transcaucasia…………………..	430	0	430
Middle East…………………….	0	0	0
Russia…………………………..	296	51	347
South Asia……………………...	0	0	0
East Asia……………………….	10	0	10
Southeast Asia and Oceania……	4	0	4
Total………………………..	4512	993	5505

[1] See table 6 for a list of countries reporting deposits of heavy oil and/or natural bitumen grouped by regions.

Appendixes 1–4

Appendix 1. Map Basin Name Conventions

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Amu Darya	Tadzhik
Arkla	Louisiana Salt Dome
Baikal	Lake Baikal
Barinas-Apure	Llanos de Casanare
Carnarvon	Dampier
Central Montana Uplift	Crazy Mountains
Central Sumatra	Sumatra, Central
East Java	Java, East
East Texas	East Texas Salt Dome
Eastern Venezuela	Maturin
Forest City	Salina-Forest City
Gulf of Alaska	Alaska, Gulf of
Gulf of Suez	Suez, Gulf of
Guyana	Guiana
Junggar	Zhungeer
Kutei	Mahakam
Mae Fang	Fang
Minusinsk	Minisinsk
North Caspian	Caspian, North
North Caucasus-Mangyshlak	Caucasus, North
North Egypt	Western Desert
North Sakhalin	Sakhalin, North
North Sumatra	Sumatra, North
North Ustyurt	Ust Urt
Northern North Sea	North Sea, Northern
Northwest Argentina	Argentina, Northwest
Northwest German	German, Northwest
Northwest Shelf	Dampier
Ordos	Shanganning
Progreso	Guayaquil
Sacramento	Sacramento/San Joaquin
Salinas	Salinas (Mexico)
San Joaquin	Sacramento/San Joaquin
South Adriatic	Adriatic, South
South Palawan	Palawan, South
South Sumatra	Sumatra, South
Timan-Pechora	Pechora
Turpan	Tulufan

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).—Continued

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Upper Magdalena	Magdalena, Upper
West Java	Java, West, Sunda
West of Shetlands	Shetlands, West
Western Canada Sedimentary	Alberta
Yukon-Kandik	Yukon/Kandik

The following basins listed in bold type are from the digital mapping file of St. John (1996) and require further explanation:

- **Anadarko**: includes provinces more commonly known as the *Anadarko,* Central Kansas Uplift, Chautauqua Platform, *Las Animas Arch,* Nemaha Anticline-Cherokee Basin, *Ozark Uplift,* Sedgwick, and South Oklahoma Folded Belt (provinces in italics report neither heavy oil nor natural bitumen.)

- **Sacramento/San Joaquin**: separated into two distinct provinces, Sacramento and San Joaquin.

- **North Sea, Southern**: : includes both the Anglo-Dutch and Southern North Sea basins.

- **South Adriatic**: includes both the Durres and South Adriatic basins.

Other comments:

Three separate outlines for Marathon, Ouachita, and Eastern Overthrust are shown as a common province Marathon/Ouachita/Eastern Overthrust in the original St John (1996) but only Ouachita Basin had reported volumes of natural bitumen resources.

Deposits reported for Eastern Venezuela basin include deposits on the island of Trinidad, which are a likely extension of the rock formations from the surface expression of the basin outline.

The plates attach the name of Barinas Apure to the polygonal province labeled Llanos de Casanare in St. John (1996). Barinas Apure is the province name commonly used in Venezuela and Llanos de Casanare is the province name commonly used in Colombia for the same geologic province.

Appendix 2. Basins, Basin Type and Location of Basins having Heavy Oil and Natural Bitumen Deposits

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.

Geological province	Klemme basin type	Country	State/Province	Other names
Aegian	IIIBc	Greece		North Aegean Trough (North Aegean Sea Basin)
Akita	IIIBa	Japan		Akita Basin, Japan Accreted Arc/Accreted Terrane
Amu-Darya	IICa	Tajikistan, Uzbekistan		Tadzhik, Surkhan-Vaksh, Badkhyz High (Murgab Basin), Afghan-Tajik
Amur	IIIBc	Georgia		
Ana Maria	IIIBb	Cuba		Zaza Basin, Greater Antilles Deformed Belt
Anabar-Lena	IIA	Russia		
Anadarko	IIA	United States	Kans.	
Anadyr	IIIBb	Russia		
Angara-Lena	IIA	Russia		
Anglo-Dutch	IIB	Netherlands		Central Graben, North Sea, Southern
Appalachian	IIA	United States	Ky., N.Y.	
Aquitaine	IIIA	France		Ales, Aquitaine, Lac Basin, Parentis, Massif Central, Pyrenean Foothills-Ebro Basin
Arabian	IICa	Bahrain, Iran, Iraq, Jordan, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria		Arabian Basin, Rub Al Khali, Aneh Graben, Aljafr Sub-basin, Oman Platform, Mesopotamian Foredeep, Palmyra Zone, Oman Sub-Basin, Euphrates/Mardin, Ghaba Salt Basin, Greater Ghawar Uplift, Haleb, Qatar Arch, South Oman Salt Basin, Widyan Basin
Arkla	IICc	United States	Ark., La.	Louisiana Salt Dome
Arkoma	IIA	United States	Ark., Okla.	
Assam	IICb	India		
Atlas	IICb	Algeria		Moroccan-Algerian-Tunisian Atlas, Hodna-Constantine
Bahia Sul	IIIC	Brazil		J Equitinhonha
Baikal	IIIA	Russia		Lake Baikal
Balearic	IIIA	Spain		Western Mediterranean, Gulf of Valencia, Barcelona Trough (Catalano-Balearic Basin), Iberic Cordillera
Baltic	I	Sweden		
Baluchistan	IICb	Pakistan		Sulaiman-Kirthar
Barbados	V	Barbados		Lesser Antilles, Northeast Caribbean Deformed Belt
Barinas-Apure	IIA	Venezuela, Colombia		Barinas-Apure Basin, Llanos de Casanare
Barito	IIIBa	Indonesia		Barito Basin
Bawean	IIIBa	Indonesia		
Beibu Gulf	IIIBa	China		Beibuwan (Gulf of Tonkin) Basin
Bengal	IICa	Bangladesh, India		Bengal (Surma Sub-basin), Tripura-Cachar, Barisal High (Bengal Basin), Ganges-Brahmaputra Delta
Beni	IIA	Bolivia		Foothill Belt
Big Horn	IIA	United States	Mont., Wyo.	
Black Mesa	IIB	United States	Ariz.	Dry Mesa, Dineh Bi Keyah
Black Warrior	IIA	United States	Ala., Miss.	
Bohai Gulf	IIIA	China		Bohai Wan (Huabei-Bohai) Basin, Huabei, Pohal, Luxi Jiaoliao Uplift

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Bombay	IIIC	India		
Bonaparte Gulf	IIIC	Australia		Berkeley Platform (Bonaparte Basin)
Bone Gulf	IIIBa	Indonesia		Bone
Bresse	IIIA	France		Jura Foldbelt
Browse	IIIC	Australia		
Brunei-Sabah	IICc	Brunei, Malaysia		Baram Delta
Cabinda	IIIC	Angola, Congo (Brazzaville), Democratic Republic of Congo (Kinshasa)		Lower Congo Basin, West-Central Coastal
Caltanisetta	IICb	Italy, Malta		Caltanissetta Basin, Ibleian Platform, Sicilian Depression
Cambay	IIIA	India		Cambay North, Bikaner-Nagam, Bombay (in part)
Campeche	IICc	Mexico		Tabasco-Campeche, Yucatan Boderland and Platform, Tobasco, Campeche-Sigsbee Salt, Villahermosa Uplift
Campos	IIIC	Brazil		Cabo Frio High (Campos Basin)
Cantabrian	IIIA	Spain		Offshore Cantabrian Foldbelt (Cantabrian Zone), Spanish Trough-Cantabrian Zone
Carnarvon	IIIC	Australia		Dampier, Northwest Shelf, Carnarvon Offshore, Barrow-Dampier Sub-Basin
Carpathian	IICb	Austria, Czech Republic, Poland, Ukraine		Carpathian Flysch, Carpathian Foredeep, Bohemia, Carpathian-Balkanian
Celtic	IIIA	Ireland		Celtic Sea Graben System, Ireland-Scotland Platform
Central Coastal	IIIBb	United States	Calif.	Coastal, Santa Cruz, Salinas Valley, Northern Coast Range
Central Kansas Uplift	IIA	United States	Kans.	Anadarko
Central Montana Uplift	IIA	United States	Mont.	Crazy Mountains
Central Sumatra	IIIBa	Indonesia		Central Sumatra Basin
Ceram	IICa	Indonesia		North Seram Basin, Banda Arc
Channel Islands	IIIBb	United States		Southern California Borderlands
Chao Phraya	IIIA	Thailand		Phitsanulok Basin, Thailand Mesozoic Basin Belt
Chautauqua Platform	IIA	United States	Okla.	Anadarko
Cincinnati Arch	I	United States	Ky., Ohio	
Cook Inlet	IIIBa	United States	Alaska	Susitna Lowlands
Cuanza	IIIC	Angola		Kwanza Basin, West-Central Coastal
Cuyo	IIB	Argentina		Alvear Sub-basin (Cuyo Basin), Cuyo-Atuel
Dead Sea	IICa	Israel, Jordan		Syrian -African Arc, Levantine, Jafr-Tabuk, Sinai
Denver	I	United States	Colo., Nebr.	Denver-Julesberg
Diyarbakir	IICa	Syria, Turkey		Bozova-Mardin High (Southeast Turkey Fold Belt), Euphrates/ Mardin, Zagros Fold Belt
Dnieper-Donets	IIIA	Ukraine		Dnepr-Donets Graben
Doba	IIIA	Chad		
Durres	IICb	Albania		Ionian Basin (zone), South Adriatic, Pre-Adriatic
East China	IIIBa	China, Taiwan		Diaoyu Island Depression (East China Sea Basin)
East Java	IIIBa	Indonesia		Bawean Arch (East Java Basin)
East Texas	IICc	United States	Tex.	East Texas Salt Dome, Ouachita Fold Belt
Eastern Venezuela	IICa	Venezuela, Trinidad and Tobago		Maturin, Eastern Venezuela Basin, Orinoco Oil Belt, Guarico Sub-basin, Trinidad-Tabago

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Espirito-Santo	IIIC	Brazil		Abrolhos Bank Sub-Basin (Espirito Santo Basin)
Fergana	IIIBc	Kyrgyzstan, Tajikistan, Uzbekistan		
Florida-Bahama	IIIC	Cuba, United States	Fla.	Almendares-San Juan Zone, Bahia Honda Zone, Llasvvillas Zone, Florida Platform, Greater Antilles Deformed Belt
Forest City	I	United States	Kans., Nebr.	Salina-Forest City, Salina, Chadron Arch
Fort Worth	IIA	United States	Tex.	Bend Arch, Fort Worth Syncline, Llano Uplift, Ouachita Overthrust
Gabon	IIIC	Gabon		Gabon Coastal Basin (Ogooue Delta), West-Central Coastal
Gaziantep	IICa	Syria, Turkey		
Ghana	IIIC	Ghana, Nigeria		Benin-Dahomey, Dahomey Coastal
Gippsland	IIIA	Australia		Gippsland Basin
Green River	IIA	United States	Colo., Wyo.	
Guangxi-Guizou	IIB	China		Bose (Baise) Basin, South China Fold Belt
Gulf Coast	IICc	United States	La., Tex.	Mid-Gulf Coast, Ouachita Folded Belt, Burgos
Gulf of Alaska	V	United States	Alaska	
Gulf of Suez	IIIA	Egypt		Gulf of Suez Basin, Red Sea Basin
Guyana	IIIC	Suriname		Guiana, Bakhuis Horst, Guyana-Suriname
Illinois	I	United States	Ill., Ky.	
Indus	IICb	India		Punjab (Bikaner-Nagaur Sub-basin), West Rajasthan
Ionian	IICb	Greece		Epirus, Peloponesus
Irkutsk	IIA	Russia		
Jeanne d'Arc	IIIC	Canada	N.L.	Labrador-Newfoundland Shelf
Jianghan	IIIA	China		Tung-T'Ing Hu
Junggar	IIIA	China		Zhungeer, Anjihai-Qigu-Yaomashan Anticlinal Zone (Junggar)
Kansk	IIA	Russia		
Krishna	IIIC	India		Krishna-Godavari Basin
Kura	IIIBc	Azerbaijan, Georgia		Kura Basin
Kutei	IIIBa	Indonesia		Mahakam
Kuznets	IIB	Russia		
Laptev	IIB	Russia		
Los Angeles	IIIBb	United States	Calif.	
MacKenzie	IV	Canada	N.W.T.	Beaufort Sea, MacKenzie Delta
Mae Fang	IIIA	Thailand		Fang, Mae Fang Basin, Tenasserim-Shan
Maracaibo	IIIBc	Venezuela, Colombia		Maracaibo Basin, Catatumbo
Mauritius-Seychelles	IIIC	Seychelles		
Mekong	IIIC	Vietnam		Mekong Delta Basin
Michigan	I	United States	Mich.	
Middle Magdalena	IIIBc	Colombia		Middle Magdalena Basin
Minusinsk	IIB	Russia		Minisinsk
Mississippi Salt Dome	IICc	United States	Ala., Miss.	
Moesian	IICb	Bulgaria, Moldova, Romania		Moesian Platform-Lom Basin, Alexandria Rosiori Depression (Moesian Platform), Carpathian-Balkanian, West Black Sea

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Molasse	IICb	Austria, Germany, Italy, Switzerland		Molasse Basin
Morondava	IIIC	Madagascar		
Mukalla	IIIC	Yemen		Sayhut Basin, Masila-Jeza
Natuna	IIIA	Indonesia		
Nemaha Anticline-Cherokee Basin	IIA	United States	Kans., Mo.	Anadarko
Neuquen	IIB	Argentina		Agrio Fold Belt (Neuquen Basin)
Niger Delta	IV	Cameroon, Equatorial Guinea, Nigeria		Abakaliki Uplift (Niger Delta)
Niigata	IIIBa	Japan		Niigata Basin, Yamagata Basin, Japan Volcanic Arc/Accreted Terrane
Nile Delta	IV	Egypt		Nile Delta Basin
North Caspian	IICa	Kazakhstan, Russia		Akatol' Uplift, Alim Basin, Beke-Bashkuduk Swell Pri-Caspian, Kobyskol' Uplift, South Emba, Tyub-Karagan
North Caucasus-Mangyshlak	IICa	Russia		Indolo-Kuban-Azov-Terek-Kuma Sub-basins, North Buzachi Arch, Middle Caspian, North Caucasus
North Egypt	IICa	Egypt		Western Desert, Abu Gharadiq
North Sakhalin	IIIBb	Russia		Sakhalin North
North Slope	IICc	United States	Alaska	Arctic Coastal Plains, Interior Lowlands, Northern Foothills, Southern Foothills, Colville
North Sumatra	IIIBa	Indonesia		North Sumatra Basin
North Ustyurt	IIB	Kazakhstan		Ust-Urt
Northern North Sea	IIIA	Norway, United Kingdom		Viking Graben, North Sea Graben
Northwest Argentina	IIA	Argentina		Carandaitycretaceous Basin
Northwest German	IIB	Germany		Jura Trough, West Holstein
Olenek	I	Russia		
Ordos	IIA	China		Shanganning, Qinling Dabieshan Fold Belt
Oriente	IIA	Peru		Acre, Maranon, Upper Amazon
Otway	IIIC	Australia		
Ouachita Overthrust	IIA	United States	Ark.	
Palo Duro	IIA	United States	N. Mex.	Tucumcari
Pannonian	IIIBc	Bosnia and Herzegovina, Croatia, Hungary, Romania, Serbia		Backa Sub-basin (Pannonian Basin)
Paradox	IIB	United States	Utah	
Paris	IIB	France		Anglo-Paris Basin
Pearl River	IIIC	China		Dongsha Uplift (Pearl River Basin), Pearl River Mouth, South China Continental Slope
Pelagian	IICa	Tunisia, Libya		
Permian	IIA	United States	N. Mex., Tex.	Ouachita Fold Belt, Bend Arch, Delaware, Midland
Peten-Chiapas	IICc	Guatemala		Chapayal (South Peten) Basin, North Peten (Paso Caballos), Sierra De Chiapas-Peten, Yucatan Platform
Piceance	IIA	United States	Colo.	
Po	IICb	Italy		Crema Sub-Basin (Po Basin)
Polish	IIIA	Poland		Danish-Polish Marginal Trough, German-Polish

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Potiguar	IIIC	Brazil		Boa Vista Graben (Potiguar Basin), North-Northeastern Region
Potwar	IICb	Pakistan		Bannu Trough (Potwar Basin), Kohat-Potwar
Powder River	IIA	United States	Mont., Wyo.	
Pripyat	IIIA	Belarus		Pripyat Graben
Progreso	IIIBb	Ecuador		Guayaquil, Gulf Of Gayaquil, Jambeli Sub-basin of Progresso Basin, Santa Elena
Putumayo	IIA	Colombia, Ecuador		Napo, Cuenca Oriente Ecuatoriana
Rhine	IIIA	France, Germany		Upper Rhine Graben
Sacramento	IIIBb	United States	Calif.	Sacramento-San Joaquin
Salawati	IICa	Indonesia		Salawati Basin, Bintuni-Salawati
Salinas	IICc	Mexico		Isthmus Of Tehuantepec, Salinas Sub-basin, Isthmus Saline, Saline Comalcalco
San Joaquin	IIIBb	United States	Calif.	Sacramento-San Joaquin
San Jorge	IIIA	Argentina		Rio Mayo, San Jorge Basin
San Juan	IIB	United States	Ariz., Colo., N. Mex.	
Santa Maria	IIIBb	United States	Calif.	
Santos	IIIC	Brazil		
Sarawak	IICc	Malaysia		Central Luconia Platform
Sedgwick	IIA	United States	Kans.	Anadarko
Senegal	IIIC	Senegal		Bove-Senegal Basins
Sergipe-Alagoas	IIIC	Brazil		Sergipe-Alagoas Basin
Shumagin	V	United States	Alaska	
Sirte	IIIA	Libya		Agedabia Trough (Sirte Basin)
Songliao	IIIA	China		
South Adriatic	IICb	Italy		Adriatic, Marche-Abruzzi Basin (Pede-Apenninic Trough), Plio-Pleist Foredeep, Scaglia
South African	IIIC	South Africa		Agulhas Arch (South African Coastal Basin)
South Burma	IIIBb	Burma		Central Burma Basin, Irrawaddy
South Caspian	IIIBc	Azerbaidjan		South Caspian OGP (Apsheron-Kobystan Region), Emba, Guriy Region
South Oklahoma Folded Belt	IIA	United States	Okla., Tex.	Anadarko
South Palawan	IIIBa	Philippines		China Sea Platform, Palawan Shelf
South Sumatra	IIIBa	Indonesia		Central Palembang Depression (South Sumatra Basin)
South Texas Salt Dome	IICc	United States	Tex.	
South Yellow Sea	IIIA	China		Central Uplift (South Huanghai Basin), Subei Yellow Sea
Southern North Sea	IIB	United Kingdom		Central Graben (North Sea Graben system), Dutsh Bank Basin (East Shetland Platform), Witch Ground Graben
Sudan	IIIA	Sudan		Kosti Sub-Basin (Melut Basin), Muglad Basin, Sudd Basin
Sunda	IIIBa	Indonesia		
Surat	IIB	Australia		
Sverdrup	IICc	Canada	N.W.T.	Mellville
Taiwan	IIIBa	Taiwan		Taihsi Basin

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Talara	IIIBb	Peru		Talara Basin
Tampico	IICc	Mexico		Tampico-Tuxpan Embayment, Chicontepec, Tampico-Misantla
Tarakan	IIIBa	Indonesia		Bera Sub-basin (Tarakan Basin), Pamusian-Tarakan
Taranto	IICb	Italy		Abruzzi Zone (Apennine Range). Marche-Abruzzi Basin (Pede-Apenninic Trough), Latium, Calabrian
Tarfaya	IIIC	Morocco		Aaiun-Tarfaya
Tarim	IIIA	China		
Thrace	IIIBc	Turkey		Thrace-Gallipoli Basin, Zagros Fold Belt
Timan-Pechora	IIB	Russia		Belaya Depression (Ural Foredeep), Brykalan Depression, Pechora-Kozhva Mega-Arch, Varendey-Adz'va
Timimoun	IIB	Algeria		Sbaa
Tonga	IIIBa	Tonga		
Tunguska	I	Russia		Baykit Antecline
Turpan	IIIA	China		Tulufan
Tyrrhenian	IIIA	Italy		
Uinta	IIA	United States	Utah	
Upper Magdalena	IIIBc	Colombia		Upper Magdalena Basin
Ventura	IIIBb	United States	Calif.	Santa Barbara Channel
Veracruz	IIIC	Mexico		
Verkhoyansk	IIA	Russia		
Vienna	IIIBc	Austria, Slovakia		Bohemia
Vilyuy	IIA	Russia		
Volga-Ural	IIA	Russia		Aksubayevo-Nurlaty Structural Zone, Bashkir Arch, Belaya Depression, Melekess Basin, Tatar Arch, Vishnevo-Polyana Terrace
Washakie	IIA	United States	Wyo.	
West Java	IIIBa	Indonesia		Arjuna Sub-Basin (West Java Basin), Northwest Java
West of Shetlands	IIIC	United Kingdom		Faeroe, West of Shetland
West Siberia	IIB	Russia		West Siberia
Western Canada Sedimentary	IIA	Canada, United States	Alta., Mont., Sask.	Alberta, Western Canada Sedimentary, Sweetgrass Arch
Western Overthrust	IIA	United States	Ariz., Mont., Nev., Utah	Central Western Overthrust, Great Basin Province, Southwest Wyoming, South Western Overthrust
Williston	I	Canada, United States	N. Dak., Sask.	Sioux Uplift
Wind River	IIA	United States	Wyo.	
Yari	IIA	Colombia		Yari Basin
Yenisey-Khatanga	IIA	Russia		
Yukon-Kandik	IIIBb	United States	Alaska	Yukon-Koyukuk
Zagros	IICa	Iran, Iraq		Zagros Fold Beltzagros or Iranian Fold Belt, Sinjar Trough, Bozova-Mardin High, Euphrates/Mardin

Appendix 3. Klemme Basin Classificaton Figure from Plate 1

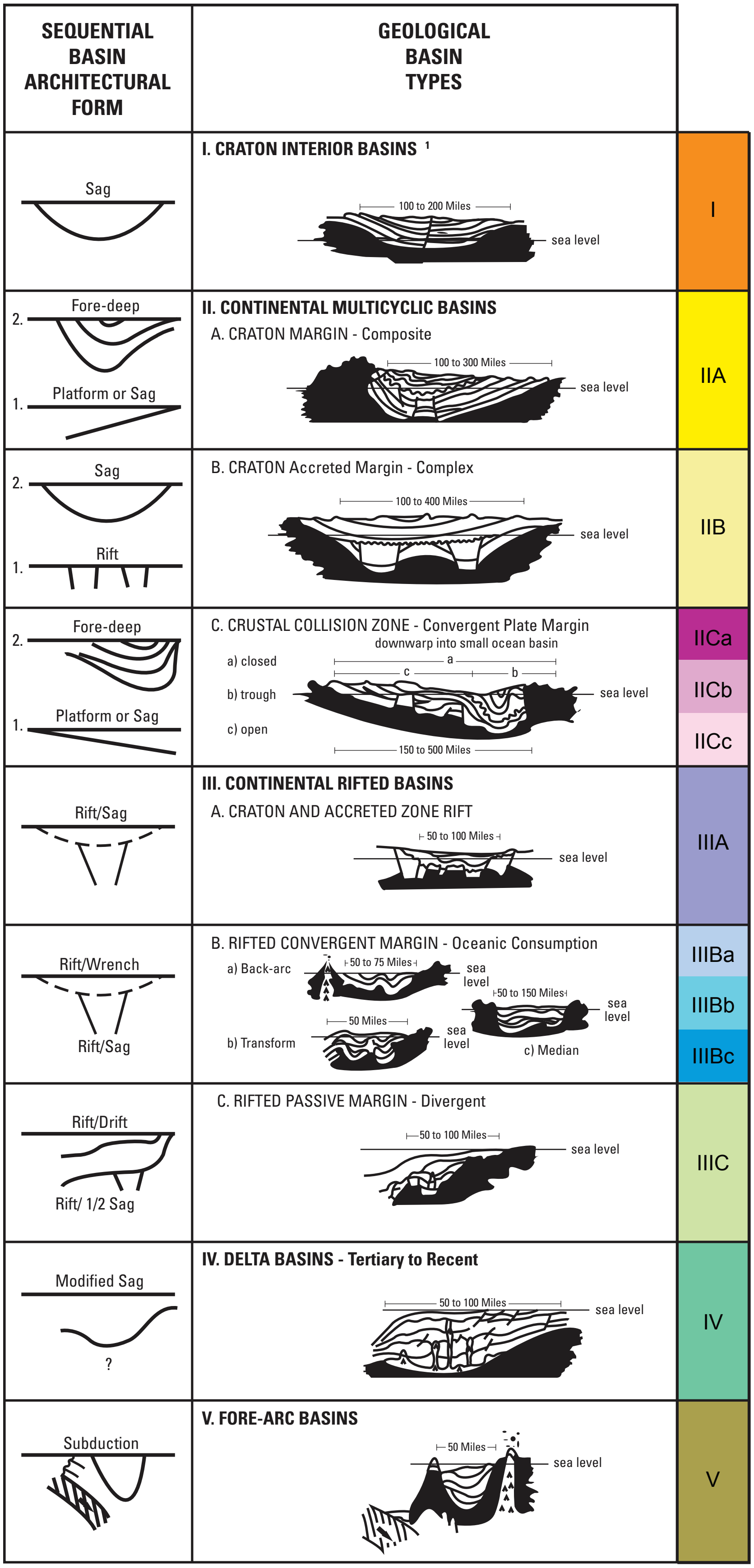

Figure 2-1. Diagram of Klemme basin types from plate 1. Modified from St. John, Bally, and Klemme (1984).

[1] Cincinati Arch is classified as I-Arch

Appendix 4. Tables from the Plates

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Arabian	IICa	842	842				
2	Eastern Venezuela	IICa	593	566	27.7	2,090	1,900	190
3	Maracaibo	IIIBc	322	322		169	169	
4	Campeche	IICc	293	293		0.060	0.060	
5	Bohai Gulf	IIIA	141	141		7.63	7.63	
6	Zagros	IICa	115	115				
7	Campos	IIIC	105	105				
8	West Siberia	IIB	88.4	88.4				
9	Tampico	IICc	65.3	65.3				
10	Western Canada Sedimentary	IIA	54.9	54.9		2,330	1,630	703
11	Timan-Pechora	IIB	54.9	54.9		22.0	22.0	
12	San Joaquin	IIIBb	53.9	53.9		< 0.01	< 0.01	
13	Putumayo	IIA	42.4	42.4		0.919	0.919	
14	Central Sumatra	IIIBa	40.6	40.6				
15	North Slope	IICc	37.0	37.0		19.0	19.0	
16	Niger Delta	IV	36.1	36.1				
17	Los Angeles	IIIBb	33.4	33.4		< 0.01	< 0.01	< 0.01
18	North Caspian	IICa	31.9	31.9		421	421	
19	Volga-Ural	IIA	26.1	26.1		263	263	
20	Ventura	IIIBb	25.2	25.2		0.505	0.505	
21	Gulf of Suez	IIIA	24.7	24.7		0.500	0.500	
22	Northern North Sea	IIIA	22.8	22.8		10.9	10.9	
23	Gulf Coast	IICc	19.7	19.7				
24	Salinas	IICc	16.6	16.6				
25	Middle Magdalena	IIIBc	16.4	16.4				
26	Pearl River	IIIC	15.7	15.7				
27	North Ustyurt	IIB	15.0	15.0				
28	Brunei-Sabah	IICc	14.7	14.7				
29	Diyarbakir	IICa	13.5	13.5				

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.—Continued

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
30	Northwest German	IIB	9.48	9.48				
31	Barinas-Apure	IIA	9.19	9.19		0.38	0.38	
32	North Caucasus-Mangyshlak	IICa	8.60	8.60		0.060	0.060	
33	Cambay	IIIA	8.28	8.28				
34	Santa Maria	IIIBb	8.06	8.06		2.03	2.02	< 0.01
35	Central Coastal	IIIBb	8.01	8.01		0.095	0.025	0.070
36	Big Horn	IIA	7.78	7.78				
37	Arkla	IICc	7.67	7.67				
38	Moesian	IICb	7.39	7.39				
39	Assam	IICb	6.16	6.16				
40	Oriente	IIA	5.92	5.92		0.250	0.250	
41	Molasse	IICb	5.79	5.79		0.010	0.010	
42	Doba	IIIA	5.35	5.35				
43	Morondava	IIIC	4.75	4.75		2.21	2.21	
44	Florida-Bahama	IIIC	4.75	4.75		0.48	0.48	
45	Southern North Sea	IIB	4.71	4.71				
46	Durres	IICb	4.70	4.70		0.37	0.37	
47	Caltanisetta	IICb	4.65	4.65		4.03	4.03	
48	Neuquen	IIB	4.56	4.56				
49	North Sakhalin	IIIBb	4.46	4.46		< 0.01	< 0.01	
50	Cabinda	IIIC	4.43	4.43		0.363	0.363	

Table 4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Western Canada Sedimentary	IIA	2,330	1,630	703
2	Eastern Venezuela	IICa	2,090	1,900	190
3	North Caspian	IICa	421	421	
4	Volga-Ural	IIA	263	263	
5	Maracaibo	IIIBc	169	169	
6	Tunguska	I	59.5	8.19	51.3
7	Ghana	IIIC	38.3	5.74	32.6
8	Timan-Pechora	IIB	22.0	22.0	
9	North Slope	IICc	19..0	19.0	
10	Uinta	IIA	11.7	7.08	4.58
11	Northern North Sea	IIIA	10.9	10.9	
12	South Caspian	IIIBc	8.84	8.84	
13	Bohai Gulf	IIIA	7.63	7.63	
14	Paradox	IIB	6.62	4.26	2.36
15	Black Warrior	IIA	6.36	1.76	
16	South Texas Salt Dome	IICc	4.88	3.87	1.01
17	Cuanza	IIIC	4.65	4.65	
18	Bone Gulf	IIIBa	4.46	4.46	
19	Caltanisetta	IICb	4.03	4.03	
20	Nemaha Anticline-Cherokee Basin	IIA	2.95	0.70	2.25
21	Morondava	IIIC	2.21	2.21	
22	Yenisey-Khatanga	IIA	2.21	2.21	
23	Santa Maria	IIIBb	2.03	2.02	<0.01
24	Junggar	IIIA	1.59	1.59	
25	Tarim	IIIA	1.25	1.25	
26	West of Shetlands	IIIC	1.00	1.00	
27	Putumayo	IIA	0.919	0.919	
28	Illinois	I	0.890	0.300	0.590
29	South Oklahoma Folded Belt	IIA	0.885	0.058	0.827
30	South Adriatic	IICb	0.510	0.510	
31	Ventura	IIIBb	0.505	0.505	
32	Gulf of Suez	IIIA	0.500	0.500	
33	Florida-Bahama	IIIC	0.477	0.477	

Attachment 22

CALIFORNIA
ENERGY
COMMISSION

TRANSPORTATION ENERGY FORECASTS AND ANALYSES FOR THE *2009 INTEGRATED ENERGY POLICY REPORT*

FINAL STAFF REPORT

MAY 2010
CEC-600-2010-002-SF

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DISCLAIMER

ACKNOWLEDGEMENTS

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Union of Concerned Scientists / Patricia Monahan

Sierra Club California / Bill Magavern

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ICF International / Gopalakrishnan Duleep, Douglas Elliott, Lawrence Mujilo

Christensen Associates Energy Consulting / Joseph Henningfield, Brad Wagner

Abt SRBI, Inc. / Lindsay Steffens, Laurie Wargelin, Thomas Adler, Mark Fowler

Please use the following citation for this report:

Gordon Schremp, Aniss Bahreinian, and Malachi Weng-Gutierrez 2010 *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*, California Energy Commission. CEC-600-2010-002-SF.

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ABSTRACT

For the *2009 Integrated Energy Policy Report*, California Energy Commission staff developed long-term forecasts of transportation fuel demand as well as projected ranges of transportation fuel and crude oil import requirements. These forecasts support analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, integration of energy use and land use planning, and transportation fuel infrastructure requirements. The projections and analysis indicate a potential need for targeted expansion of import infrastructure, particularly marine import facilities, to offset declining in-state oil production and growing demand in California, Nevada, and Arizona for transportation fuels. The magnitude of future contributions from efficiency improvements and various emerging transportation fuels and technologies is highly uncertain. Staff found that efficiency and emerging fuels and technologies can potentially displace significant amounts of petroleum, which will reduce the need for petroleum-specific infrastructure enhancements. However, many of these alternative fuels, in particular renewable fuels, may also require their own additional segregated import facilities, including pipelines and storage tanks. Moreover, developing the means of distributing these emerging alternative fuels, particularly through public retail refueling sites and home recharging systems, and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government.

Keywords:

California demand forecasts, transportation energy, gasoline, diesel, jet fuel, crude oil production, renewable fuels, alternative fuels, fuel imports, crude oil imports, marine import infrastructure, refining capacity, consumer preference, pipeline exports, retail refueling infrastructure, fuel prices, ethanol, E85, biodiesel, RFS, LCFS, FFV, CNG, hydrogen

EXECUTIVE SUMMARY

Background

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), requires the California Energy Commission to conduct "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices to develop policies for its *Integrated Energy Policy Report.*" The Energy Commission develops long-term projections of California transportation energy demand that support its analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, integration of energy use and land-use planning, and transportation fuel infrastructure requirements.

This report summarizes the transportation energy demand forecasts, quantifies the petroleum and petroleum product-equivalent supply needs to meet the forecasted transportation energy demand, and identifies emerging constraints on transportation fuels infrastructure required to meet California's future transportation fuel demand. California's petroleum infrastructure is composed of the import and export system for petroleum, petroleum products, and renewable blendstocks; in-state refineries; and the distribution and storage network, made up of pipelines, trucks, rail, and storage tanks, that move petroleum, petroleum products, and renewable blendstocks to and from in-state refineries and to the refueling infrastructure. Increasingly, this transportation energy system will have to accommodate emerging renewable and alternative fuels that have their own sources of supply, as well as separate import, distribution, and retail refueling infrastructure.

While the Energy Commission expects consumption of transportation energy in California to increase in the future under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels can potentially displace significant amounts of petroleum, which can reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its unique set of marketing, supply, infrastructure, and regulatory issues constraining market penetration. Moreover, developing the means of distributing these emerging fuels through public retail refueling sites and home recharging systems and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government.

Selected Findings

The following represent some of the more important findings from the supporting analyses. Chapter 1 provides a more comprehensive summary listing.

Petroleum Transportation Fuels Demand Trends and Forecasts

- California average daily gasoline demand for the first six months of 2009 is 1.0 percent lower compared to the same period in 2008, continuing a declining trend since 2004. Over the 12-month period from July 2008 through June 2009, gasoline demand is down 3.4 percent compared to the previous 12-month period.
- California average daily diesel fuel demand for the first six months of 2009 is 8.4 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the 12-month period from July 2008 through June 2009, diesel fuel demand declined to 10.1 percent compared to the previous 12-month period.
- Between 2005 and 2007, California jet fuel demand rose 5 percent but from 2007 to 2008 declined 8.9 percent.
- Between 2007 and 2030, staff estimates total annual gasoline consumption in California to fall 13.3 percent in the low-demand case to 13.57 billion gallons, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. In the high-demand case, the recovering economy and lower relative prices lead to a gasoline demand peak in 2014 of 16.40 billion gallons before consumption falls to a 2030 level of 14.32 billion gallons, 8.5 percent below 2007 levels.
- These forecasted volumes have not been adjusted to account for compliance with the revised federal Renewable Fuel Standard (RFS) fair share obligations that further decrease demand for gasoline (E10) and greatly increase the demand outlook for E85. Under the low-demand case, gasoline demand is decreased from 13.57 billion gallons in 2030 to 11.86 billion gallons. In the high-demand case, the gasoline forecast of 14.32 billion gallons by 2030 is further decreased to 13.03 billion gallons as a consequence of the RFS.
- Between 2007 and 2030, staff expects total diesel demand in California to increase 35 percent in the low-demand case to 5.138 billion gallons and 42 percent in the high-demand case to 5.399 billion gallons.
- Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the low demand case, and 67.2 percent to 5.75 billion gallons in the high-demand case.

Renewable and Alternative Fuels

Ethanol

- Ethanol use in California gasoline is expected to increase from an average concentration of between 6 and 7 percent by volume in 2009 to levels ranging between 8 and 10 percent in 2010, primarily due to federal regulations mandating greater use of renewable fuels and transition to a revised state reformulated gasoline regulation. For forecasting, staff has assumed 10 percent blending for 2010 but recognizes that some refiners and other marketers have the flexibility to use lower concentrations in their proprietary systems.

- The federal Renewable Fuels Standards 2 will require more renewable fuels, primarily ethanol, and to a lesser extent biodiesel. Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1.272 billion gallons in 2010 to 2.778 billion gallons by 2020. Under the High-Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1.299 billion gallons in 2010 to 2.639 billion gallons by 2020.

- It is estimated that ethanol demand in California due to Renewable Fuels Standards 2 requirements will exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on the gasoline demand growth rates. However, it is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10), even if the U.S. Environmental Protection Agency ultimately grants permission for United States refiners and marketers to go to E15.

- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with the Renewable Fuels Standards 2 requirements. Assuming a 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 1.1 million gallons in 2010 to 1,725 million gallons in 2020 and 2,262 million gallons by 2030 under the Low Demand Case for gasoline. However, the pace of this expansion may be hindered due to a variety of infrastructure challenges and disincentives.

- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between 4,400 and 30,900 E85 dispensers by 2022. To put that figure in perspective, there were approximately 42,050 total retail fuel dispensers in the entire state during 2008. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion.

- Over the near term, the greatest barrier to expanded use of ethanol is an adequate and timely build-out of the necessary minimum E85 retail fueling infrastructure capability. E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and appurtenances range between $50,000 and $200,000. This level of investment is between 1.5 and 6 times greater than the total annual profit of a typical retail station (for both fuel and non-fuel commodities). It is estimated that, at a minimum, an average of 545 E85 dispensers per year would need to be installed in California between 2014 and 2022, costing between $27 million and $218 million per year.

- What type of base gasoline will be necessary to blend with ethanol to produce E85? If the blendstock is something other than California reformulated blendstock for oxygenate blending (CARBOB) for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

- California's number of registered flexible fuel vehicles must increase from a total of 382,000 vehicles in October 2008 to as many as 4.8 million flexible fuel vehicles by 2020 and 7.3 million by 2030 to help ensure that sufficient volumes of E85 can be sold to meet growing mandated ethanol blending requirements.
- The proposed Renewable Fuels Standards 2 regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders must comply with the Renewable Fuels Standards 2 requirements, but retail station operators have no obligation. This is an apparent "disconnect" in the Renewable Fuels Standards 2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.
- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the Renewable Fuels Standards 2 obligations in 2010. Therefore, the U.S. Environmental Protection Agency should delay the cellulosic obligations until commercial production capacity is actually operational. Specifically, U.S. Environmental Protection Agency could set the national cellulosic ethanol use requirement for each January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.
- The Low Carbon Fuel Standard will change the mix of ethanol types that will be used in California, namely ethanol from the Midwest, which will become more difficult to use, while ethanol from Brazil (sugar cane-based) will become increasingly attractive. Although the carbon intensity reductions of the Low Carbon Fuel Standard appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.
- Blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the Low Carbon Fuel Standard without requiring any off-setting carbon credits. The only exceptions are California ethanol facilities that have dry distillers grain with solubles coproducts and certain sources of Midwest ethanol.
- The Low Carbon Fuel Standard is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities, such as ethanol produced from sugarcane in Brazil. California's logistical infrastructure for the importation and redistribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.
- California's ethanol import and redistribution infrastructure will need to change rather quickly to accommodate the anticipated transition to 10 percent (E10) blending beginning January 1, 2010. It is likely that an adequate infrastructure will be in place to increase ethanol blending by more than 50 percent (compared to 2009 levels).
- If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. Infrastructure projects to accommodate both means of receipt are being pursued but have yet to begin construction.

Biodiesel

- A growing percentage of total U.S. biodiesel supply has been exported, rather than used in domestic transportation fuels. Biodiesel exports have grown from nearly 9 million gallons in 2004 to more than 677 million gallons in 2008 due to more attractive wholesale prices and U.S. exporters' use of the dollar-per-gallon biodiesel blenders' credit. In 2008 alone, export volumes represented 68 percent of total U.S. biodiesel supplies (production combined with imports).

- However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently applied a combination of import duties designed to compensate for the economic advantage gained by United States biodiesel exporters from the dollar per gallon blenders' credit.

- The Renewable Fuels Standards 2 regulations call for a minimum use of 1 billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity and another 289 million gallons per year capacity under construction. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the Renewable Fuels Standards 2 requirements for several years.

- Under the Low Diesel Demand Case, biomass-based diesel "fair share" (F*air share* refers to California's fair share of renewable fuel consumption under the Renewable Fuels Standards 2.) ranges from 41 million gallons in 2010 to 72 million gallons by 2030. Under the High Diesel Demand Case – biodiesel "fair share" ranges from 41 million gallons in 2010 to 70 million gallons by 2030.

- If biodiesel demand necessitated by California's Low Carbon Fuel Standard (LCFS) approaches 10 percent by volume, biodiesel demand could reach between 435 million gallons by 2020 and 540 million gallons by 2030. Further, B20 levels would imply biodiesel demand levels in California of 870 million gallons by 2020 and 1,080 million gallons by 2030.

- Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), distribution terminal modifications could be undertaken and completed to enable an expansion of biodiesel use.

- As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel do pose some barriers that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume.

Other Alternative Fuels

- Natural gas has demonstrated a broad range of transportation applications, including light-, medium-, and heavy-duty uses in personal, transit, commercial, and freight roles, although overall numbers of vehicles are relatively small. The technology has also proven to have significant potential for carbon reduction, which can be further developed by advances in biogas technology.

- Lack of vehicle offerings, high vehicle cost and reduced range compared to gasoline vehicles, consumer unfamiliarity with the technology, and the need for investment in refueling infrastructure are among the more pressing impediments to developing transportation natural gas potential.

- California's use of natural gas in the transportation sector is forecasted to increase at a rate of between 1.7 and 2.6 percent per year, rising from 150.1 million therms in 2007 to between 222.9 million to 270.3 million therms by 2030. The number of compressed natural gas vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030. However, these light-duty compressed natural gas vehicles will only represent up to 30 percent of the demand for transportation sector natural gas by 2030. The larger portion of total natural gas demand will still come from the urban public transit sector.

- Electric vehicle technology has the potential to significantly reduce carbon emissions and petroleum use. Fuel costs can also be considerably less than conventional petroleum fuels, taking into account the energy efficiency of the vehicle, especially given favorable rates for time of use metering and designated second meters.

- Consumer perceptions of electric vehicle technology vary widely. While full electric vehicles (FEV's) are not generally viewed favorably, compared to gasoline vehicles, plug-in hybrids appear to generate a much more positive impression.

- Battery costs outweigh all other incremental cost factors in the production of these vehicles and must be lowered to improve the commercial viability of the product. Increased reliance on lithium-ion battery technology will necessitate more rigorous assessment of the availability of lithium supply.

- California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of plug-in hybrid electric vehicles. As measured in gigawatt hours (GWhs), demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. The forecasted surge in transportation electricity use is mainly from plug-in hybrid electric vehicles and to lesser extent full electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

- Not enough information on consumer acceptance, vehicle availability, and infrastructure development is available to forecast future fuel cell vehicle purchases and hydrogen fuel use at this time. Fuel cell vehicles need to be brought out of the research and development stage to fully evaluate their commercial and environmental potential.

- A wide variety of methods and feedstocks can be used in the production of hydrogen fuel. GHG reduction factors are greatly influenced by the process used, but generally the carbon and petroleum reduction potential is very high.

- Standard measurements and fuel quality specifications need to be established to promote the sale of hydrogen as a transportation fuel.

Crude Oil Import Forecast

- California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than any point since 1985. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States, by 36.3 percent. Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year.

- In 2008, California refiners imported 406 million barrels of crude oil. Crude oil imports are continuing to increase throughout the forecast period, requiring an expansion of the existing crude oil import infrastructure to ensure a continued adequate supply of feedstock to enable refiners to operate their facilities at levels sufficient to supply California and the neighboring states with projected quantities of transportation fuels to meet forecasted demand.

- Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by

2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008).

- Under the High Case projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015 (17.3 percent increase), by 113 million barrels by 2020 (28 percent increase) and by 190 million barrels by 2030 (47 percent increase compared to 2008).
- Southern California will require an expansion of the existing crude oil import infrastructure to avoid detrimental impact on refinery operations. Although progress continues in developing Berth 408 in the Port of Los Angeles, the time required to obtain all of the necessary permits to begin construction is now more than four years. In fact, Plains All-American, a company engaged in the transportation, storage, terminalling and marketing of crude oil and refined products, still does not have all of the requisite approvals necessary for them to initiate construction.
- Additional storage tank capacity would have to be constructed to handle the incremental imports of crude oil, between 1.5 million and 5.8 million barrels by 2015; between 2.4 million and 9.5 million barrels by 2020; and between 4.0 million and 15.9 million barrels of storage capacity by 2030.
- The continued decline of California’s crude oil production could be reversed through increased exploration and drilling in state and federal waters, but any appreciable impact on the level of imported oil would be at least a decade away. If the lifting of the moratoria on Outer Continental Shelf drilling off the coast of California remains and expanded exploration and development is allowed to proceed, crude oil production off the coast could increase from 110,000 barrels per day in 2008 to approximately 310,000 barrels per day by 2020 and 480,000 barrels per day by 2030.

Petroleum Product Import Forecast

- Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona’s demand was met by products exported from California. However, that percentage dropped to just 35 percent by 2008 as refiners and other marketers shifted source of supply from California and Texas and New Mexico.
- Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account pipeline expansion plans between Texas and Arizona, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.
- The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.
- Under the High Import Case analysis, California imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would still rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalances between gasoline and the other transportation fuels are even more extreme, resulting in a net decline of imports of at least 115,000 barrels per day by 2015. This latter type of outcome is unlikely to materialize as refiners

will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed.

CHAPTER 1: Introduction to Transportation Energy Forecasts

Transportation Energy Analyses

As required by SB 1389, the California Energy Commission conducts "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." The Energy Commission reports these assessments and forecasts in its *Integrated Energy Policy Report* (*IEPR*), which it adopts every odd-numbered year (Public Resources Code [PRC] §25302[d]).

Transportation energy demand and fuel price forecasts support several state energy policy and program activities, including the alternative vehicle and fuel technology analysis mandated by Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005); petroleum use reduction and efficiency assessments; land-use planning analysis; and transportation energy infrastructure requirements assessment. Since the *2007 IEPR*, Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) has been signed into law, the Low Carbon Fuel Standards (LCFS) have been adopted by the California Air Resources Board (ARB), and the 2009 American Recovery and Reinvestment Act (ARRA) was enacted. SB 375 links greenhouse gas (GHG) reductions with transportation funding, land-use planning, and housing policy, which in turn requires more integration of land-use and transportation models. The LCFS sets carbon reduction standards that will affect the types of fuels that can be sold in California, particularly renewable fuels. The federal stimulus bill has increased the incentives available to higher efficiency and alternative fuel technologies.

While the Energy Commission expects consumption of transportation energy in California to increase under a variety of fuel price and regulatory conditions, there are substantial uncertainties associated with the future contributions of various renewable and alternative transportation fuels and technologies. These emerging fuels can potentially displace significant amounts of petroleum, which can reduce the need for petroleum-specific infrastructure enhancements. However, each of these alternative fuels has its unique set of supply, infrastructure, and regulatory issues constraining market penetration. Moreover, developing the means of distributing these emerging fuels through public retail refueling sites and home recharging systems and aligning the development of these refueling systems with the rollout of appropriate numbers of vehicles may prove to be a challenge to industry and government. These issues will be discussed in Chapter 3.

This revised report provides final transportation energy analyses for the *2009 IEPR* with a focus on the implications of future transportation energy demand for California's existing transportation fuels marine import facilities, as well as the state's retail refueling infrastructure. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol. Staff incorporated additional alternative fuel vehicles and technologies, as compared with the staff report for the *2007 IEPR*.[i]

Summary of Staff Findings

The outlook for the adequacy of California's petroleum transportation fuel import infrastructure has improved slightly since publication of the *2007 IEPR*. This has occurred because of lower expectations of demand for these fuels due to general economic factors, higher fuel prices, and policies intended to reduce petroleum consumption. At the same time, other issues have risen with respect to meeting new state and federal low-carbon and renewable fuel standards, as well as the sufficiency of supply and adequacy of import and distribution infrastructure for renewable and alternative fuels.

Numerous uncertainties can affect these estimates of future import and distribution infrastructure needs, including changes in fuel prices, rates of adoption of new technologies and alternative fuels, demand for fuels in California and neighboring states, decline rates of oil production in California, refinery and other infrastructure capacity expansions, and GHG reduction rules and standards. Moreover, as with all technical analysis, uncertainties will also be introduced with the use of forecasting models and other analytical tools, including the use of surveys and other data sources to calibrate and estimate models and the use of forecasts of input variables by other organizations. However, potential supply and capacity shortfalls lead staff to conclude that specific kinds of import and refueling infrastructure capacity expansions may need to occur to prevent economic losses to state consumers.

Staff has generated two crude oil price scenarios, representing plausible and sustainable long-term low and high crude oil prices. Each of these two crude price paths is also associated with a low and high price band for ethanol, natural gas, and electricity, generating four fuel price cases from the possible combinations. From these cases, the highest and lowest petroleum demand cases were analyzed for their compliance with existing low-carbon and renewable fuels standards and effects on import and distribution infrastructure. In the summary findings below, the highest and lowest expected demand levels for the petroleum fuels are reported as a range. On the supply side, staff developed high and low cases of crude oil and fuel import requirements that vary according to assumptions about crude oil production, refinery and pipeline expansion projects, port and marine terminal capacities, and California and neighboring state fuel demand. Staff also identified and attempted to quantify other factors that will affect the forecast of imports requirements. Findings that result from the development of these forecasts and analyses include the following:

Trends in Transportation

- Between 2009 and 2030, population is forecast to increase at an annual compound average rate of 1.1 percent, compared with a growth rate of 2.9 percent in real personal income over the same period. These rates of growth will result in substantial increases in travel demand for California.
- While projected population growth to 2030 has remained the same between the 2007 and 2009 forecasts, non-farm employment projections have been lowered in the 2009 forecast, resulting in a sharp decline in the percentage of California population employed.
- Between 2001 and 2008 the number of all alternative fueled vehicle types has increased in the state at rates substantially greater than for gasoline vehicles. This growth is particularly pronounced for hybrid electric vehicles at 75 percent over this period.
- Between 2004 and 2008 the percentage of new light-duty vehicle sales that were small and large cars grew significantly, with corresponding decreases in the shares of trucks and sport utility vehicles.
- The 2008 California Vehicle Survey (CVS) verifies the significant impact of distance to work and availability of transit on vehicle miles traveled. Therefore, changes in land use patterns that reduce the distance between locations of job and residence, and increase the availability of urban transit, will reduce vehicle miles traveled and transportation

fuel consumption per capita. Fuel costs have a significant influence on both vehicle choice and vehicle miles traveled.

- Between 2000 and 2008, the percentage of medium- and heavy-duty vehicles fueled by gasoline has fallen from 52 percent to less than 39 percent, with most of their share being taken over by diesel vehicles. Among alternative fuels, natural gas vehicles have built the largest share at slightly over 1 percent.

- Substantial growth in import container traffic at California ports has been an important factor in freight transportation energy use since 2000. However, the economic downturn has caused a decline of 15.7 percent in daily average container traffic during the first 11 months of 2009 when compared to 2008 and down 23.5 percent when compared to 2007.

- Data through the week ending December 19, 2009, show that rail carload activity is down 16.5 percent compared to the same period in 2008. Intermodal rail activity is also down 14.6 percent, while estimated ton-miles of rail activity declined 15.5 percent compared to 2008. Domestic trucking activity is down 7.3 percent in September 2009 when compared to September 2008.

- California average daily gasoline demand for the first six months of 2009 is 1.0 percent lower compared to the same period in 2008, continuing a declining trend since 2004. Over the 12-month period of July 2008 through June 2009, gasoline demand is down 3.4 percent compared to the previous 12-month period.

- California average daily diesel fuel demand for the first six months of 2009 is 8.4 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the 12-month period of July 2008 through June 2009, diesel fuel demand is down 10.1 percent compared to the previous 12-month period.

- Between 2005 and 2007, California jet fuel demand rose 5 percent but from 2007 to 2008 declined 8.9 percent.

- Among 45 California transit agencies for which data was available from the American Public Transportation Association (APTA), ridership increased by 2.2 percent, to 1.34 billion trips, between 2007 and 2008.

Petroleum Transportation Fuel Demand Forecasts

- Between 2007 and 2030, staff estimates total annual gasoline consumption in California to fall 13.3 percent in the low-demand case to 13.57 billion gallons, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. In the high-demand case, the recovering economy and lower relative prices lead to a gasoline demand peak in 2014 of 16.40 billion gallons before consumption falls to a 2030 level of 14.32 billion gallons, 8.5 percent below 2007 levels.

- These forecasted volumes have not been adjusted to account for compliance with the revised federal Renewable Fuel Standard (RFS) fair share obligations that further decrease demand for gasoline (E10) and greatly increase the demand outlook for E85. Under the Low Demand Case, gasoline demand is decreased from 13.57 billion gallons in 2030 to 11.86 billion gallons. In the High Demand Case, the gasoline forecast of 14.32 billion gallons by 2030 is further decreased to 13.03 billion gallons as a consequence of the RFS.

- Between 2007 and 2030, staff expects total diesel demand in California to increase 35 percent in the Low Demand Case to 5.138 billion gallons and 42 percent in the High Demand Case to 5.399 billion gallons.

- Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the Low Demand Case, and 67.2 percent to 5.75 billion gallons in the High Demand Case.

Renewable and Alternative Fuels

Ethanol

- Ethanol use in California gasoline is expected to increase from an average concentration of between 6 and 7 percent by volume in 2009 to levels ranging between 8 and 10 percent in 2010, primarily due to federal regulations mandating greater use of renewable fuels and transition to a revised state reformulated gasoline regulation. For forecasting purposes staff has assumed 10 percent blending for 2010 but recognizes that some refiners and other marketers have the flexibility to use lower concentrations in their proprietary systems.

- Renewable Fuels Standards 2 (RFS2) will require greater use of renewable fuels, primarily ethanol and, to a lesser extent, biodiesel.

- Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,272 million gallons in 2010 to 2,778 million gallons by 2020.

- Under the High Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,299 million gallons in 2010 to 2,639 million gallons by 2020.

- It is estimated that ethanol demand in California will eclipse an average of 10 percent by volume in all gasoline sales by between 2012 and 2013, depending on the gasoline demand growth rates.

- It is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10), even if the United States Environmental Protection Agency (U.S. EPA) ultimately grants permission for United States refiners and marketers to go to E15.

- Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with RFS2 requirements. Assuming a maximum 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 1.1 million gallons in 2010 to 1,725 million gallons in 2020 and 2,262 million gallons by 2030 under the Low Demand Case for gasoline. However, the pace of this expansion may be inadequate to achieve compliance due to a variety of infrastructure challenges and disincentives.

- Depending on the amount of fuel sold for a typical E85 dispenser, California would require between 4,400 and 30,900 E85 dispensers by 2022. To put that figure in perspective, there were approximately 42,050 total retail fuel dispensers in the entire state during 2008. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion.

- What type of base gasoline will be necessary to blend with ethanol to produce E85? If the blendstock is something other than California Reformulated Blendstock for Oxygenate Blending (CARBOB) for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

- California's number of registered flexible fuel vehicles (FFVs) will need to increase from a total of 382,000 vehicles in October 2008 to as many as 4.8 million FFVs by 2020 and 7.3 million by 2030 to help ensure that sufficient volumes of E85 can be sold to meet growing mandated ethanol blending requirements.

- The proposed RFS2 regulations do not have any requirements that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the RFS2 standards, but retail station operators do not have any obligation. This is an apparent “disconnect” in the RFS2 policy that could easily result in a retail infrastructure that cannot handle the necessary increase in E85 sales.

- Over the near term, the greatest barrier to expanded use of ethanol is an adequate and timely build-out of the necessary minimum E85 retail fueling infrastructure capability. E85 retail infrastructure is expensive. Costs for installing a new underground storage tank (UST), dispenser, and appurtenances range between $50,000 and $200,000. This level of investment is between 1.5 and 6 times greater than the total annual profit of a typical retail station (for both fuel and non-fuel commodities). It is estimated that, at a minimum, an average of 545 E85 dispensers per year would need to be installed in California between 2014 and 2022, costing between $27 million and $218 million per year.

- Regulations adopted by ARB designed to reduce emissions from new vehicle models (both tailpipe and evaporative), along with revised zero emission vehicle (ZEV) standards will require automobile manufacturer compliance with more stringent emission standards and growing percentage of ZEV and partial zero emission vehicle (PZEV) sales. Both of these sets of standards will create significant challenges for greater introduction of FFVs.

- It is possible that vehicle manufacturer marketing decisions might preclude FFVs, setting the stage for a potential shortfall of new FFV vehicle availability in California in sufficient numbers to help meet compliance with the RFS2 renewable fuel obligations.

- Ethanol producers prefer to sell into the low-blend market of E6 or E10 due to higher likelihood of receiving near-gasoline prices. The E85 market is a less desirable outlet for their ethanol production, hence the reason ethanol producers support raising the ethanol “blend wall” from E10 to E15.

- Due to the lower energy content of a gallon of E85 versus a gallon of E10 (approximately 23 to 28 percent), ethanol suppliers and retailers will likely need to sell their product at a discount to achieve necessary sales volumes. This market differentiation will exacerbate current poor ethanol production economics.

- Renewable Identification Number (RIN) credit levels may not be sufficient to overcome the economic value of the fuel economy differential, even if one assumes that the blenders receiving the RIN credit revenue will be willing to pass some of that money back through to ethanol producers in the form of higher wholesale ethanol prices.

- As California sales of E85 increase, there should be steps taken to help ensure that FFV motorists are receiving adequate pricing information at retail stations to put them in a position of making more informed fuel purchase decisions. An example of increased consumer information would be for the Legislature to consider requiring retail station owners to affix labels on each face of E85 retail dispensers with language similar to “the fuel economy of an FFV using E85 is approximately 23 to 28 percent less when compared to E10.”

- LCFS will change the mix of ethanol types that will be used in California. Namely, corn-based ethanol from the Midwest will become increasingly difficult to use, while ethanol from Brazil (sugar cane-based) will become increasingly attractive.

- Although the carbon intensity reductions of the LCFS appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.

- Brazilian ethanol may be blended in E10 for several years (up through 2016) without carbon credit offsets. California ethanol is viable in E10 blends for up to four years before it would need to be exported for use outside California or blended as E85. Finally, Midwest ethanol blending would be most limited, only able to be blended for a couple of years assuming the ethanol plant had wet distillers grain with solubles (DGS) as a co-product.

- Blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the LCFS without the need for any offsetting carbon credits. The only exceptions are California ethanol facilities that have dry DGS coproducts and certain sources of Midwest ethanol.

- Additional pathways with lower carbon intensities (CI) can extend the length that ethanol can be used in gasoline blends for either E10 or E85. Verification of lower CI pathways is expected to continue over the next couple of years. This is especially the case once cellulosic ethanol and diesel fuel production is achieved and verified on a commercial scale.

- As of June 2009 there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States. Production capacity of conventional ethanol is expected to be adequate over the next several years as facilities resume operations and new producers come on-line after completing their construction projects.

- It is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the RFS2 obligations in 2010. Therefore, the U.S. EPA should delay the cellulosic obligations until commercial production capacity is actually operational. Specifically, the U.S. EPA could set the national cellulosic ethanol use requirement for each January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.

- Currently, four of the six California ethanol facilities are idle with a collective production capacity of nearly 184 million gallons per year. These facilities are expected to resume operations sometime during 2010.

- Production of ethanol in Brazil is primarily determined by interrelationships between sugar market values and local renewable transportation demand. There may or may not be ample excess supplies of ethanol available to export from Brazil any given year.

- Brazilian exporters of ethanol to the United States must pay two types of import tariffs that total nearly 60 cents per gallon. Removing the tariff could reduce the price of ethanol in the United States by 2.5 to 14 percent, a potential benefit to consumers.

- The amount of excess ethanol that may be available to import from Brazil over the next several years is forecast to grow to between 1.9 billion and 3.2 billion gallons by 2015.

- The market price for Brazil ethanol imports is expected to command a premium to California-sourced ethanol, which should be more valuable than conventional corn-based ethanol produced outside the state. The anticipated higher, yet unknown, prices are assumed to be passed along to consumers.

- The LCFS is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities, such as ethanol produced from sugar cane in Brazil. California's logistical infrastructure for the importation and re-distribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months.
- Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest.
- California's ethanol import and redistribution infrastructure will need to change rather quickly to accommodate the anticipated transition from E6 to E10 blending beginning January 1, 2010. It is likely that an adequate infrastructure will be in place to increase ethanol blending by more than 50 percent (compared to 2009 levels).
- If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. Infrastructure projects to accommodate both means of receipt are being pursued but have yet to begin construction.

Agriculture

- As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. The portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 32.3 percent of domestic corn use in 2008.
- However, near-continuous yield improvement (as measured in bushels harvested per acre) through improved agricultural practices have enabled greater production of corn without any significant expansion of the number of acres planted.
- The application rate per acre of corn for nitrogen has increased 6.2 percent between 1980 and 2005, while the average corn yield has increased 62.5 percent over the same period. The continued improvement of corn yields is primarily a consequence of other improvements unrelated to increased use of nitrogen per acre.
- Corn yields are forecast to rise from 153.8 bushels per acre harvested in 2008 to 175.0 bushels per acre by 2018, an increase of 13.8 percent. According to the United States Department of Agriculture (USDA), the quantity of corn for production of fuel ethanol is forecast at 4.825 billion bushels for market year 2015/16, compared to 3.27 billion bushels in 2008.
- The majority of corn is grown without the use of any irrigated water, solely dependent on rainfall during the growing season. In 2007, only 15.3 percent of corn acres were irrigated with the balance (84.7 percent) receiving no irrigated water.

Biodiesel

- Biodiesel exports have grown from nearly 9 million gallons in 2004 to more than 677 million gallons in 2008 due to more attractive wholesale prices and U.S. exporters' use of the dollar per gallon biodiesel blenders' credit.
- A growing percentage of total U.S. biodiesel supply has been exported, rather than used in domestic transportation fuels. In 2008 alone, export volumes represented 68 percent of total United States biodiesel supplies (production combined with imports).

- However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently taken action to apply a combination of import duties designed to compensate for the economic advantage gained by U.S. biodiesel exporters from the dollar per gallon blenders' credit.
- Absent the large increase of biodiesel exports, blending levels in the United States could have increased to an average of 1.29 percent during 2008, rather than the actual 2008 average of 0.61 percent.
- Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations.
- There has been no quantitative analysis performed to determine how the volumes and types of biodiesel used in California could change as a consequence of the LCFS. When additional carbon intensity pathways for various types of biodiesel are published, the Energy Commission will conduct additional analysis to identify any potential supply or infrastructure issues that could result over the near to mid-term period.
- If biodiesel demand necessitated by California's Low Carbon Fuel Standard (LCFS) approaches 10 percent by volume, biodiesel demand could reach between 435 million gallons by 2020 and 540 million gallons by 2030. Further, B20 levels would infer biodiesel demand levels in California of 870 million gallons by 2020 and 1,080 million gallons by 2030.
- Under the Low Diesel Demand Case – biodiesel "fair share" for California ranges from 41 million gallons in 2010 to 72 million gallons by 2030. Under the High Diesel Demand Case – biodiesel "fair share" ranges from 41 million gallons in 2010 to 70 million gallons by 2030.
- The RFS2 regulations call for a minimum use of 1 billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity, and another 289 million gallons per year capacity under construction. It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years.
- The biodiesel infrastructure in California has not been developed to the same extent as that of ethanol primarily because there has not been any meaningful increase in the use of biodiesel to date.
- Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use.
- Distribution terminal modifications will need to be made over the near to mid-term to help ensure sufficient volumes of biodiesel will be available for blending with conventional diesel fuel.
- As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel pose some barriers that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume.

Natural Gas

- Natural gas has demonstrated a broad range of transportation applications, including light-, medium-, and heavy-duty uses in personal, transit, commercial, and freight roles, although overall numbers of vehicles are relatively small. The technology has also proven to have significant potential for carbon reduction, which can be further developed by advances in biogas technology.

- Lack of vehicle offerings, high vehicle cost and reduced range compared to gasoline vehicles, consumer unfamiliarity with the technology, and the need for investment in refueling infrastructure are among the more pressing impediments to developing transportation natural gas potential.

- California's use of natural gas in the transportation sector is forecasted to increase at a rate of between 1.7 and 2.6 percent per year, rising from 150.1 million therms in 2007 to between 222.9 million to 270.3 million therms by 2030. The number of compressed natural gas (CNG) vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030 in the High Natural Gas Demand Case. However, these light-duty CNG vehicles will represent only up to 30 percent of the demand for transportation sector natural gas by 2030. The larger portion of total natural gas demand will still come from the urban public transit sector.

- Current public refueling infrastructure varies widely by region. Initially, infrastructure development should be matched geographically with locations of greatest vehicle density.

- Developments that could stimulate transportation natural gas uses include new utility rate structures for home refueling, improved on-board storage technology, new hybrid natural gas technology, and use of carbon credits in investment plans.

- Effects on the natural gas supply system of increased transportation consumption, as well as other potential competing uses, will need to be more carefully evaluated.

Electricity

- Electric vehicle technology has the potential to significantly reduce carbon emissions and petroleum use. Fuel costs can also be considerably less than conventional petroleum fuels, taking into account the energy efficiency of the vehicle, especially given favorable rates for time-of-use metering and designated second meters.

- Consumer perceptions of electric vehicle technology vary widely. While full electric vehicles (FEVs) are not generally viewed favorably when compared to gasoline vehicles, plug-in hybrids appear to generate a much more positive impression.

- California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of PHEVs. As measured in gigawatt hours (GWhs), demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. The forecasted surge in transportation electricity use is mainly from PHEVs and to lesser extent full electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

- Much more effort should be focused on development of residential refueling infrastructure. Standardized methods and equipment for the powering of these FEVs and plug-in hybrid electric vehicles (PHEVs) need to be established, and training for technicians in installation and servicing needs to be more widely available.

- Battery costs outweigh all other incremental cost factors in the production of these vehicles and must be lowered to improve the commercial viability of the product. Increased reliance on lithium-ion battery technology will necessitate more rigorous assessment of the availability of lithium supply.

- Impacts on the electricity supply system of widespread adoption of electric transportation technology will also need to be more carefully evaluated.

Hydrogen

- Not enough information on consumer acceptance, vehicle availability, and infrastructure development is available to forecast future fuel cell vehicle purchases and hydrogen fuel use at this time. Fuel cell vehicles need to be brought out of the research and development stage to fully evaluate their commercial and environmental potential.

- A wide variety of methods and feedstocks can be used in the production of hydrogen fuel. GHG reduction factors are greatly influenced by the process used, but generally the carbon and petroleum reduction potential is very high.

- Standard measurements and fuel quality specifications need to be established to promote the sale of hydrogen as a transportation fuel. Further, the California Division of Measurement Standards recognizes that establishing a comprehensive set of accuracy and advertising standards for commercially available hydrogen fuel is a critical first step in the development of a fair and competitive marketplace in the California Hydrogen Highway infrastructure.

Crude Oil Import Forecast

- California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than any point since 1985. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States, by 36.3 percent. Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year.

- Between 2001 and 2008, California refinery creep (the gradual growth of California refinery capacity to process crude oil) for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year.

- In 2008, California refiners imported 406 million barrels of crude oil. Crude oil imports are continuing to increase throughout the forecast period, necessitating an expansion of the existing crude oil import infrastructure to ensure a continued adequate supply of feedstock to enable refiners to operate their facilities at levels sufficient to supply California and the neighboring states with projected quantities of transportation fuels to meet forecasted demand.

- Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by 2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008).

- Under the High Case projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015 (17.3 percent increase), by 113 million barrels by 2020 (28.0 percent increase), and by 190 million barrels by 2030 (47.0 percent increase compared to 2008).

- Southern California is forecast to require an expansion of the existing crude oil import infrastructure to avoid detrimental effects on refinery operations. Although progress continues with regard to developing Berth 408 in the Port of Los Angeles, the time required to obtain all of the necessary permits to begin construction has been stretched to more than four years. In fact, Plains All-American still does not have all of the requisite approvals necessary for it to initiate construction.

- The increased imports of crude oil are expected to result in a greater number of marine vessels (referred to as crude oil tankers) arriving in California ports, 17 to 100 additional crude oil tanker arrivals per year by 2015, 28 to 162 by 2020, and 46 to 272 additional arrivals per year by 2030.

- Additional storage tank capacity would have to be constructed to handle the incremental imports of crude oil, between 1.5 million and 5.8 million barrels by 2015; between 2.4 million and 9.5 million barrels by 2020; and between 4.0 million and 15.9 million barrels of storage capacity by 2030.

- The continued decline of California's crude oil production could be reversed through increased exploration and drilling in state and federal waters, but any appreciable impact on the level of imported oil would be at least a decade away. If the lifting of the moratoria on Outer Continental Shelf (OCS) drilling off the coast of California remains and expanded exploration and development is allowed to proceed, crude oil production off the coast could increase from 110,000 barrels per day in 2008 to approximately 310,000 barrels per day by 2020 and 480,000 barrels per day by 2030.

- If such an expanded drilling scenario were to be pursued by federal, state, and local governments, a new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations would likely be required to achieve this forecast level of incremental crude oil production. It is unknown what portion of the untapped economically recoverable crude oil OCS reserves are close to any of the existing 22 offshore platforms (in federal OCS waters) such that directional drilling could be employed to increase production without constructing any new platforms and associated infrastructure.

- Even under this expanded federal OCS drilling scenario, California refiners would still need to import additional quantities of crude oil for the scenario that includes 0.45 percent per year refinery creep. However, the quantities required would be 16 to 22 percent lower than the initial crude oil import forecast by 2015, 80 to 119 percent lower by 2020, and 80 to 168 percent lower compared to the forecasted level of imports for 2030. This means that under the zero refinery capacity creep scenario, the expanded federal OCS drilling could decrease crude oil imports from 2008, but certainly not eliminate crude oil imports.

- If the Tranquillon Ridge Project were to move forward, offshore crude oil production from Platform Irene could increase by up to 28,000 barrels per day within one or two years. However, this increased crude oil supply from local sources will only reduce the forecasted level of crude oil imports in 2015 by 13 to 27 percent and in 2020 by 9 to 18 percent.

- Although an expansion of the federal Strategic Petroleum Reserve to the West Coast is not being actively pursued by Congress or the United States Department of Energy (U.S. DOE), the placement of strategic crude oil storage in California could decrease the likelihood of refinery production decline in the event of a temporary loss of crude oil deliveries to California. There has been no engineering analysis performed to date for quantifying an estimated range of cost for such a project.

Petroleum Product Import Forecast

- Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona's demand was met by products exported from California. However, that percentage dropped to just 35 percent by 2008 as refiners and other marketers shifted source of supply away from California and over to Texas and New Mexico.
- Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.
- The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.
- Under the High Import Case analysis, California imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would still need to rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalance for gasoline increases and the incremental imports for other transportation fuels are lessened, resulting in a net decline of total imports of at least 115,000 barrels per day by 2015. It is recognized that this latter type of outcome is unlikely to materialize as refiners will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed.

CHAPTER 2: Transportation Fuel Demand Trends and Forecasts

This chapter provides information on current economic, demographic, and transportation-related demand trends, as well as staff's proposed California transportation fuel demand cases for the *2009 IEPR*. Since these projections are based on updated input data and models, the uncertainties in the input values used in the demand models will also be discussed briefly.

California's transportation fuel demand has changed over time in response to growth in population, variation in fuel prices, evolving vehicle and fuel technologies, the health of the economy, and environmental regulations. These changes have collectively influenced both vehicle choice and driving behavior. Among the more important recent factors are the 2008 crude oil and fuel price volatility and recessionary economic conditions. For example, crude oil prices rose to over $140 per barrel in July 2008, before declining sharply to a level below $30 in December, but have since roughly doubled again to over $60 during July 2009. At its highest peak, in June 2008, the United States Energy Information Administration (U.S. EIA) reports the average price of California regular-grade motor gasoline was $4.48 per gallon. By December 2008 the price fell to $1.82, before rising again to $2.92 in June 2009. According to adjusted California Board of Equalization (BOE) data, California sales of gasoline fell by 6.3 percent from 2004 to 2008.

Forecast Uncertainties

In addition to uncertainties inherent in the data and specifications used in any forecasting model, there are uncertainties associated with the use of other public or private sector forecasts as inputs to these models. Changes in the regulatory environment, land-use patterns, and fuel and vehicle technology, as well as the unusual transportation fuel price fluctuations add to the uncertainties of fuel demand forecasts.

Increasing environmental concerns have led California to assess and adopt a number of rules and regulations aimed at reducing harmful emissions. The latest in a series of rules and regulations is the adoption of the Low Carbon Fuel Standard (LCFS). These California rules, to be fully enforced in 2012, will require all participants in the transportation fuels market to reduce carbon intensity measured by the sum of greenhouse gas (GHG) emissions in all stages of transportation fuel production and consumption. This will involve different measures including the greatly increased use of alternative fuels and vehicle technology. By enhancing the existing surveys and models, staff has attempted to assess the markets for more vehicles and transportation fuels that can emerge to serve as alternatives to conventional petroleum fuels and vehicles. The absence of a long enough history and wide enough markets for these alternative and emerging vehicles and transportation fuels has limited consensus and added to the uncertainties associated with staff's analysis, beyond the uncertainties introduced by current economic conditions.

Uncertainties associated with crude oil and fuel price forecasts and the regulatory environment are addressed with scenario building, but manufacturer product offerings and economic and demographic projections are input into the model without expressly accounting for their inherent uncertainties. Potential changes in land-use patterns and varying development of refueling infrastructure will also add to the uncertainties of the transportation fuel demand forecasts. Forecast volatility for annual forecasts will tend to be lower and lessen the impacts of transportation fuel demand's seasonal nature. The following section will outline some of the important projections used as inputs into the forecasts and discuss a few of their implications.

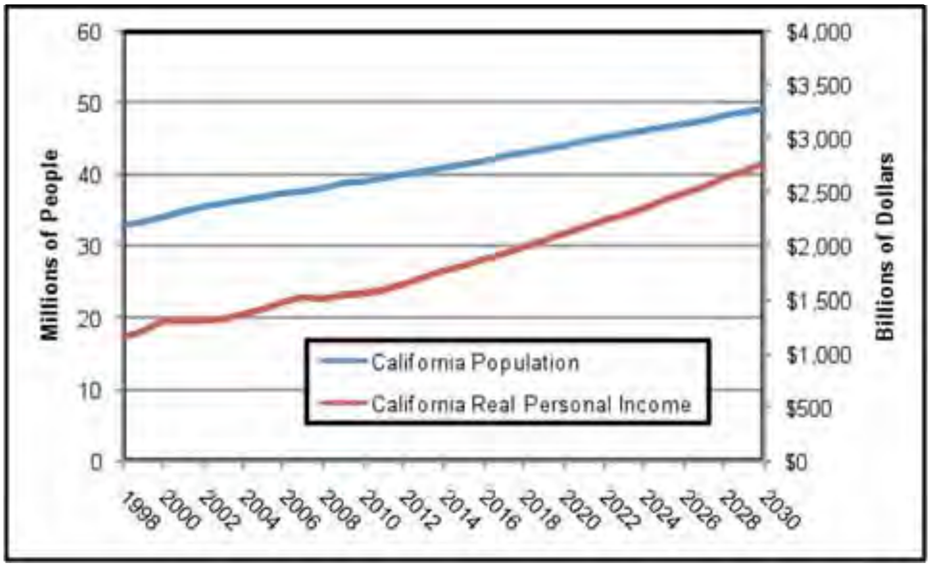
Current Transportation Trends and Projections of Input Variables

In this section staff provides information and data on trends of various transportation demand-related indicators, as well as economic, demographic, and other variables. The section also provides information on projections of important variables used as inputs for modeling transportation energy demand.

Actual and Projected Demographic and Economic Trends Related to Fuel Demand Forecasts

Between 1990 and 2008, California’s population and personal income increased by 28 and 60 percent, respectively. Over the next 20 years (2009 to 2029), the California Department of Finance (DOF) and Moody’s forecast growth of 25 and 76 percent, respectively, in California’s population and income. Figure 2.1 shows actual and forecast data on personal income and population over the 1998-2030 period. Between 2009 and 2030, population will increase at an annual compound average rate of 1.1 percent, compared with a growth rate of 2.9 percent in real personal income over the same period. These rates of growth remain significant and will result in substantial increases in travel demand for California.

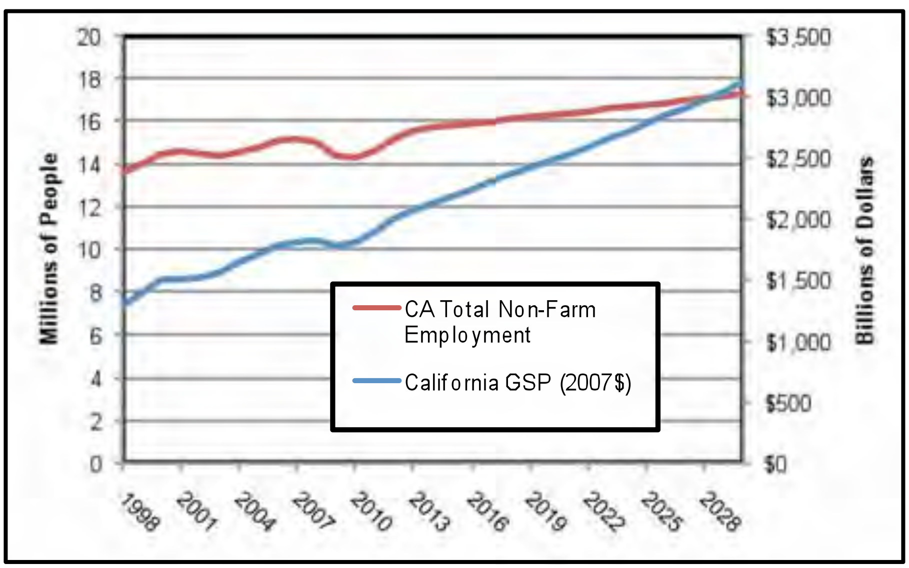
Figure 2.1: California Population and Income History and Forecasts 1998 to 2030



Sources: Department of Finance and Moody's economy.com

From 1998 to 2008 California's Gross State Product (GSP) increased by 40 percent in real terms, rising from $1.3 trillion to $1.82 trillion (2007 dollars). Employment growth was much less pronounced during the same period and shows historical growth of 10 percent from 1998 and 2008. Figure 2.2 reflects the impact of recession on the 2009 and 2010 GSP and employment forecasts. Between 2008 and 2009 both GSP and employment declined, by 2.07 and 4.27 percent, respectively, and only GSP is projected to return to a positive growth by 2010.

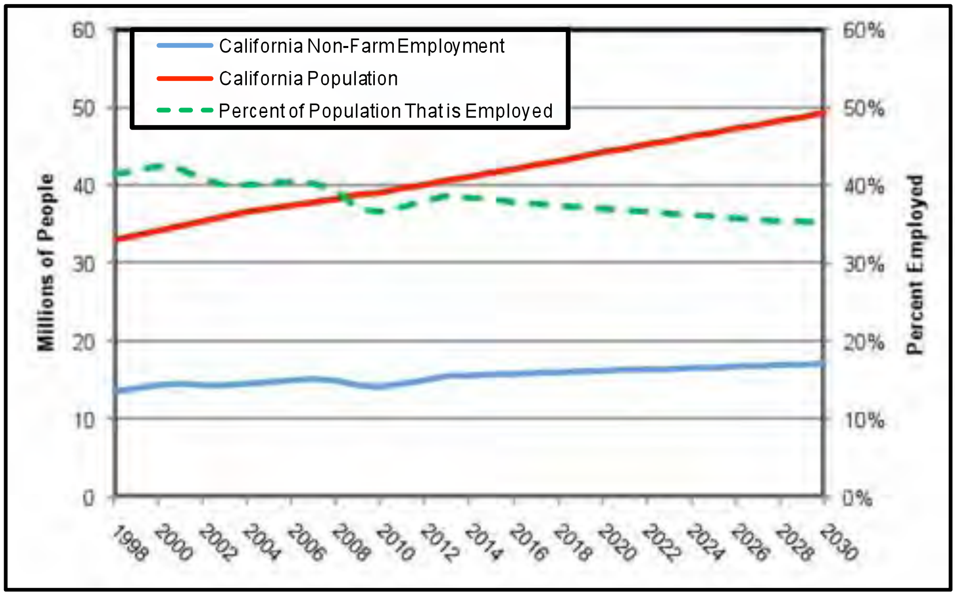
Figure 2.2: California GSP and Employment History and Forecasts 1998 to 2030



Source: Moody's economy.com

Figure 2.3 shows the relationship between California's population and non-farm employment. This suggests that the forecasted growth in non-farm employment will not keep pace with the growth in population over the same period. Non-farm employment is projected to grow 20 percent during the forecast period of 2009-2030, in contrast with higher projected growth rates for both population and GSP. Total non-farm employment does not begin to exhibit positive growth until 2011 and does not return to 2008 levels until 2012.

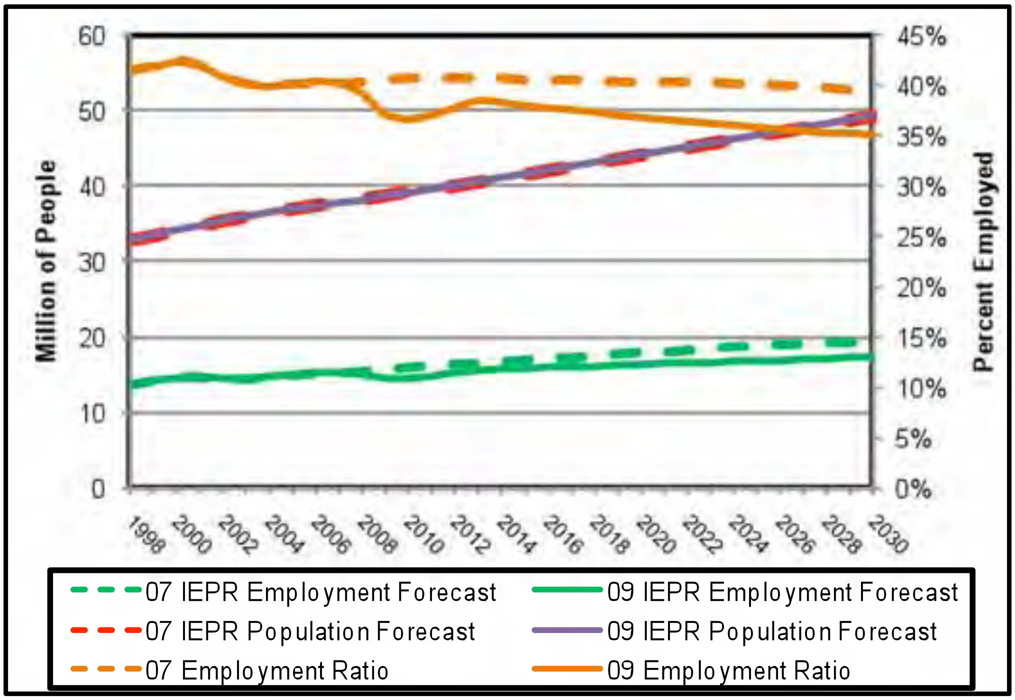
Figure 2.3: California Population and Employment History and Forecasts 1998 to 2030



Source: Department of Finance and Moody's economy.com

Figure 2.4 contrasts 2007 and 2009 projections of population and employment. While the population growth to 2030 has remained the same between the two forecasts, non-farm employment projections have been lowered in the 2009 forecast, resulting in a sharp decline in the percentage of California population employed.

Figure 2.4: California Population, GSP, and Employment Projections Used in the 2007 and 2009 *IEPRs*



Source: Department of Finance and Moody's economy.com

In 2008, part-time employment as a percentage of total employment also increased by 1.3 percent to 18.5 percent.

Historical Light-Duty Vehicle Acquisition

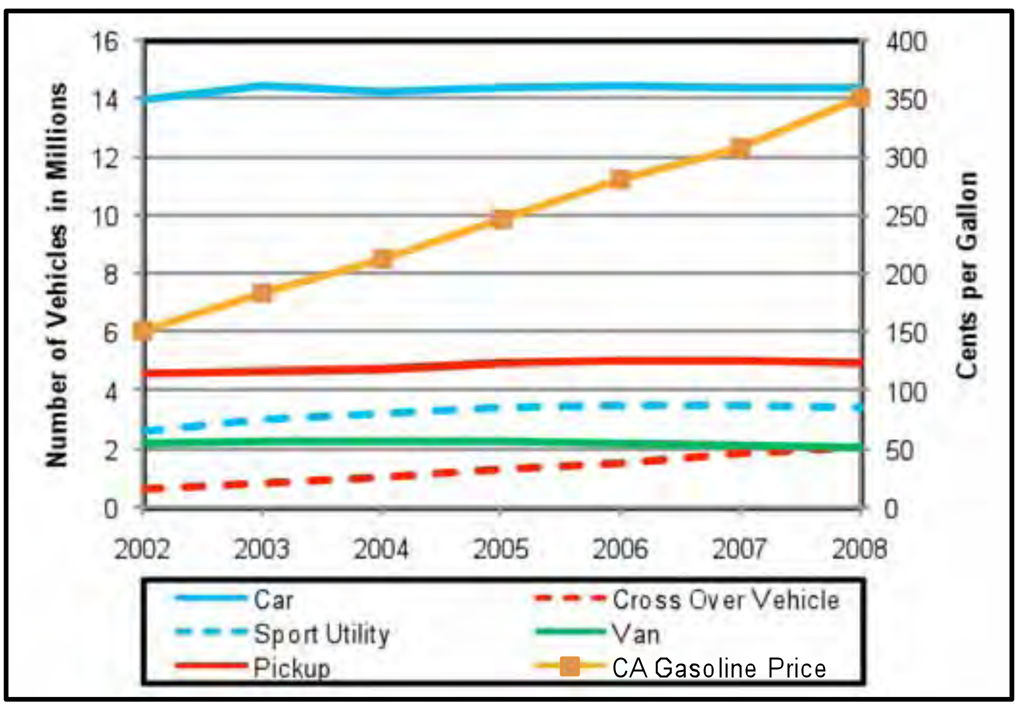
Staff reviewed recent trends in California vehicle acquisitions from the Department of Motor Vehicles (DMV) Vehicle Registration Database.[ii] The number of alternative fuel vehicles on the road in California has increased at rates substantially higher than growth rates for gasoline vehicles. However, the total number of alternative fuel vehicles in California is still small compared to the number of gasoline and diesel vehicles. Table 2.1 and Figures 2.5 and 2.6 provide information for on-road vehicle registration data from the California DMV for 2001 to 2008.

Table 2.1: Summary of California On-Road Light-Duty Vehicles

Light Duty Vehicle Counts						
	Gasoline	**Diesel**	**Hybrid**	**Flex Fuel**	**Electric**	**Natural Gas**[iii]
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
Compound Average Growth Rate	**1.71%**	**5.59%**	**75.06%**	**21.50%**	**26.03%**	**34.71%**

Source: California Energy Commission analysis of California DMV data, October file passes for 2001 through 2008

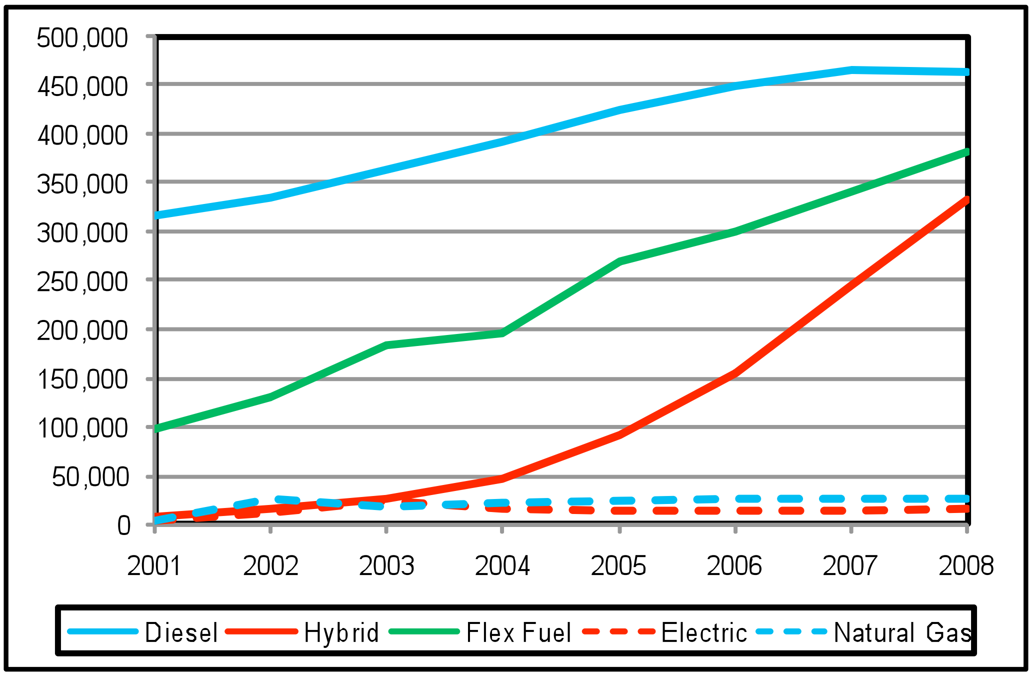
Figure 2.5: Population of California Non-Gasoline On-Road Light-Duty Vehicles by Body Type



Source: California Energy Commission analysis of California DMV data, October file passes 2002 through 2008

Figure 2.6 shows the continued growth of FFVs and hybrid vehicles in California in 2008, but a slight decline in diesel light-duty vehicles in the same year. Ethanol used for FFVs, however, amounts to less than 10 gallons a year per vehicle in 2008, partly due to the disparity between FFVs and ethanol fuel station distributions in different counties. For instance, there is only one fuel station for the 90,000 FFVs registered in Los Angeles County. Natural gas and electric vehicles do not show a significant change between 2005 and 2008.

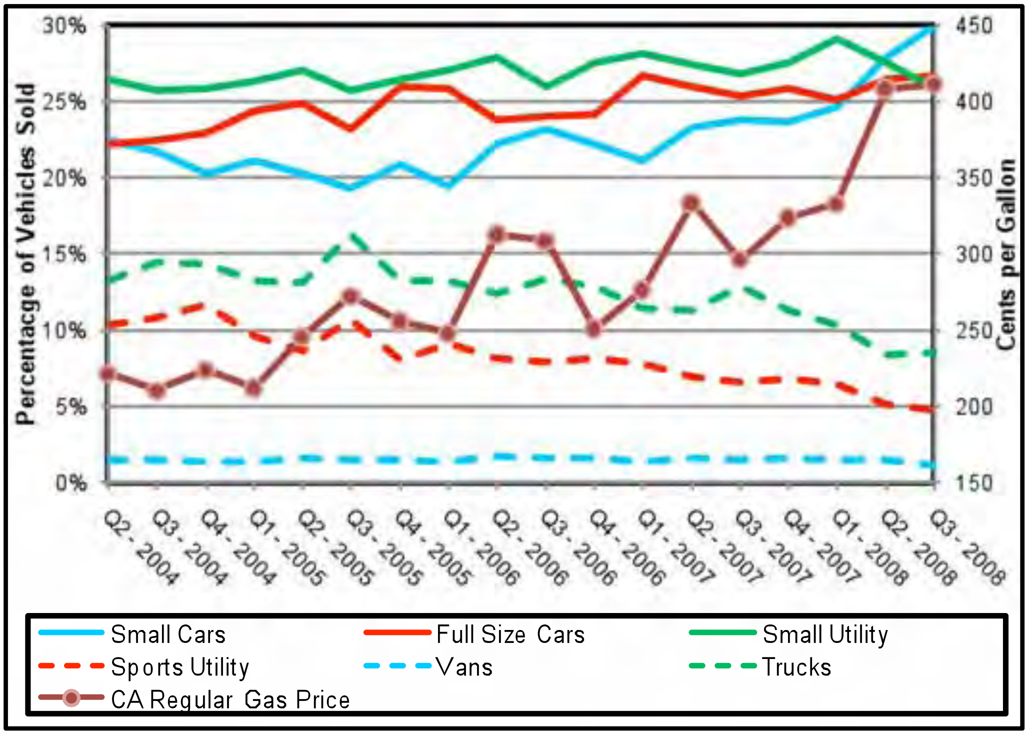
Figure 2.6: Population of California Non-Gasoline On-Road Light-Duty Vehicles by Fuel Type



Source: California Energy Commission analysis of California DMV data, October file passes 2001 through 2008

Figure 2.7 shows the percentage by type of new vehicles sold by year and quarter starting from April 2004 to September 2008. Available data for 2008 indicate increased market share for cars, especially small cars, at the expense of trucks and utility vehicles.

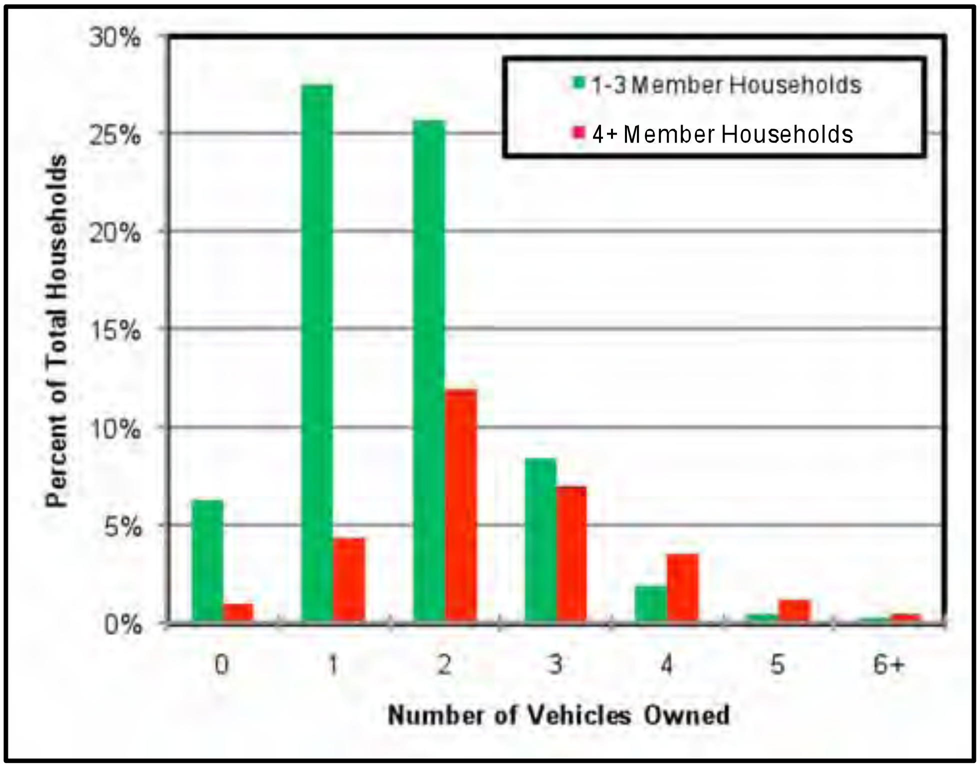
Figure 2.7: Percentage of New Vehicles Sold by Vehicle Type



Source: California Energy Commission analysis of California DMV data, file passes from April 2004 to October 2008

Figure 2.8 shows that over 70 percent of California households have one to three members, and nearly 85 percent of these households have two or fewer vehicles. Not surprisingly, a larger percentage of larger households own two or more vehicles; however, ownership of 2 or more vehicles differ only by 1 percent between households with 1 to 3 members and those households with 4 or greater members.

Figure 2.8: Percentage of California Households by Vehicle Ownership and Household Size, 2007



Source: American Community Survey, 2009

California Driver Age Demographics

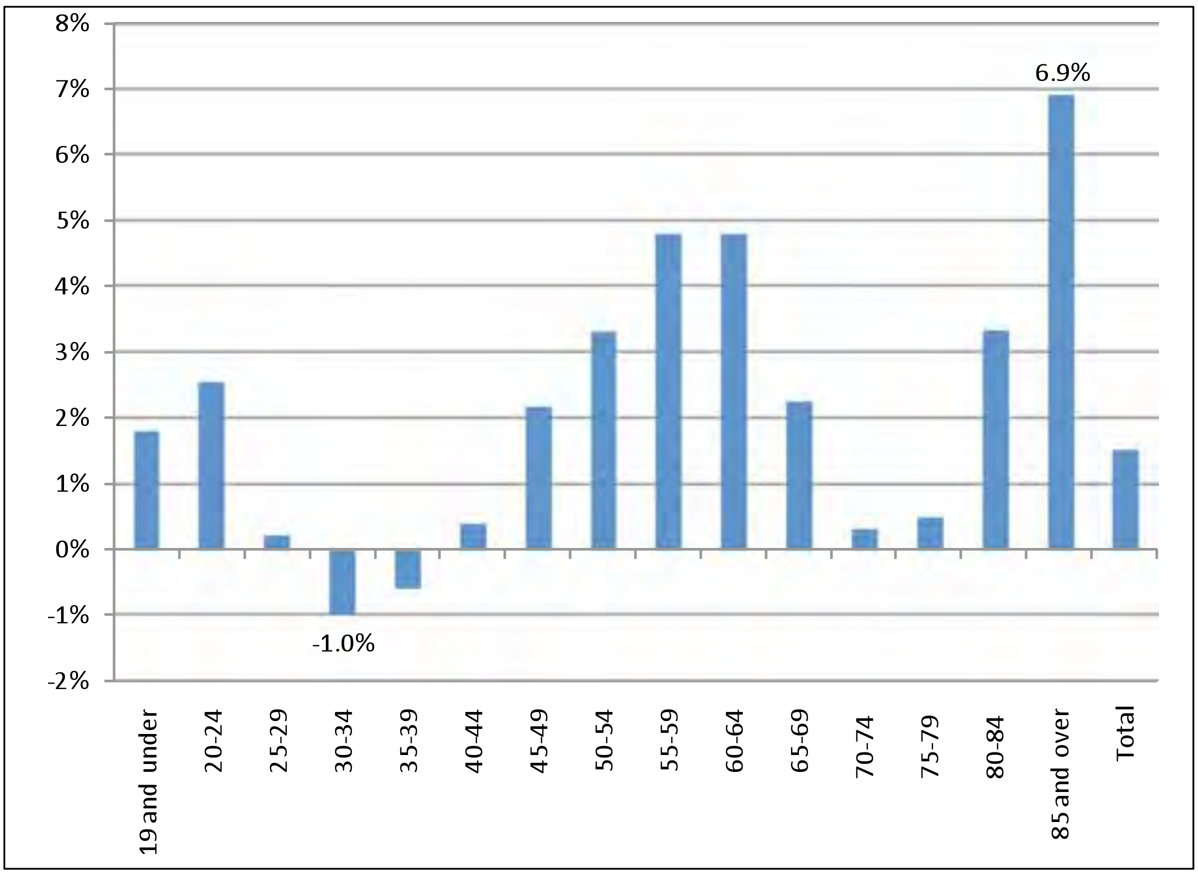
The total number of drivers in California has increased 1.5 percent annually from 1998 to 2007. (See Table 2.2.) California drivers are also getting older with most age groups over 45 showing increases of at least 2 percent per year, while the age group of "20-24" was the only younger segment showing a similar growth rate (see Figure 2.9). The age group with the largest increase was drivers over 85 years of age, growing at an annual rate of 6.9 percent. Over this period there was an annual decrease of 1.0 percent for drivers of ages 30 to 34.

Table 2.2: California Driver Age Demographics (1998 and 2007)

Age Group	1998 Drivers	Percent of Total	2007 Drivers	Percent of Total
19 and under	806,332	3.93%	945,539	4.03%
20's	3,845,391	18.76%	4,314,006	18.38%
30's	4,946,521	24.13%	4,604,714	19.62%
40's	4,484,079	21.87%	5,011,354	21.35%
50's	2,968,677	14.48%	4,206,388	17.92%
60's	1,786,639	8.72%	2,473,874	10.54%
70's	1,241,885	6.06%	1,285,811	5.48%
80 and over	419,378	2.05%	625,766	2.67%

Source: http://www.fhwa.dot.gov/policy/ohpi/qFdrivers.cfm

Figure 2.9: Annual Average Growth Rate for California Drivers By Age Group (1998 through 2007)



Source: California Energy Commission analysis of California DMV data, October file passes 2002 through 2008

California Consumer Vehicle and Fuel Use Preferences

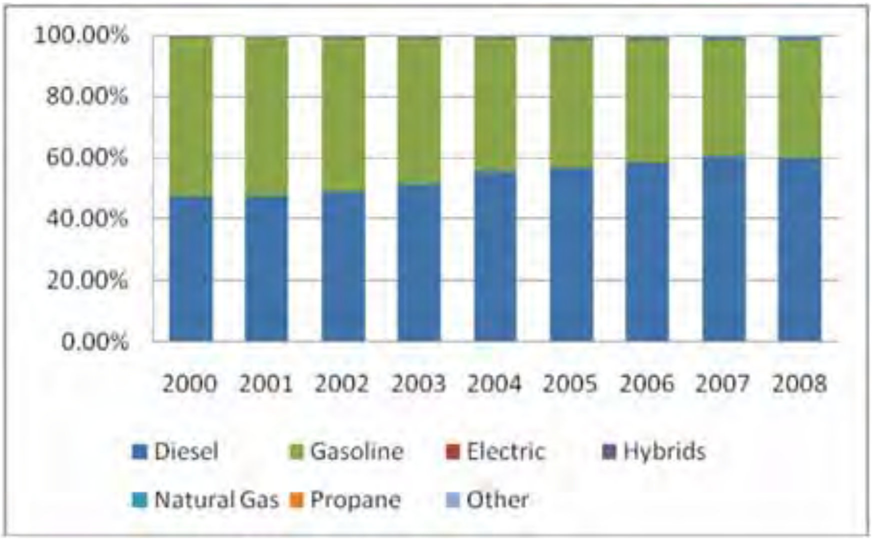
The 2008 California Vehicle Survey (CVS) was conducted to capture California consumers' preferences for light-duty vehicles and transportation fuels. The survey collected data on the *revealed* preferences of 6,577 households and 3,452 commercial sector vehicle owners. Of these survey participants, 3,274 households and 1,780 commercial vehicle owners provided their *stated* preferences for vehicles of varying attributes. Survey data was used to model household and commercial sector vehicle choice and ownership behavior, as well as vehicle miles traveled by California households.

The CVS verifies the significant impact of distance to work and availability of transit on vehicle miles traveled. Therefore, changes in land-use patterns that reduce the distance between locations of job and residence, and increase the availability of urban transit, will reduce vehicle miles traveled and transportation fuel consumption per capita. Fuel costs have a significant influence on both vehicle choice and vehicle miles traveled. California consumers, assuming equal prices and availability, do not differentiate significantly between E85 and gasoline in their preferences. Similarly, assuming all else equal, consumers more favorably view hybrid (including plug-in hybrids) and diesel vehicles but have less favorable impressions of compressed natural gas (CNG) and full electric vehicles, compared with gasoline vehicles. Vehicle price and fuel cost are both highly significant factors in the vehicle choice models, suggesting an awareness by California consumers of the tradeoff between these cost factors. The survey results showed that of all the incentives examined, the $1000 tax credit was viewed most favorably by all sizes of households and the High Occupancy Vehicle (HOV) lane use was the most significant incentive for commercial sector buyers. Other incentives are more influential on vehicle choice decisions of the households that own more than one vehicle. The most important regional differences were in the higher consumer preferences for hybrid vehicles in San Francisco and for HOV lane use incentives in Los Angeles.

Historical Medium- and Heavy-Duty Vehicle Stock

Medium- and heavy-duty vehicles are used primarily in the freight and transit sectors. Gross vehicle weight rating (GVWR) designates the maximum amount of weight for a vehicle in each vehicle class. GVWR Class 1 and Class 2 vehicles are vehicles that have a GVWR of 10,000 lbs or less and are generally described as light-duty vehicles[iv], while GVWR Classes 3 to 8 are assigned to vehicles with a GVWR greater than 10,000 lbs and described as medium- and heavy-duty vehicles. Figure 2.10 shows the annual medium and heavy- duty vehicle population percentages by fuel type for vehicle Classes 3 to 8.

Figure 2.10: Annual Percentage Distribution of Class 3 Through 8 (Medium- and Heavy-Duty) Vehicles by Fuel Type



Source: DMV Registration Database, October file passes from 2000 through 2008

Table 2.3 shows the vehicle populations for six fuel types and one technology category. The natural gas vehicle category is defined to include vehicles fueled by either CNG or liquefied natural gas (LNG). Vehicles classified as "Other" use fuels not listed, such as methanol, hydrogen, and butane. The population of gasoline vehicles decreased from 52 percent in 2000 to 38 percent in 2008, with diesel vehicles making up most of the difference by rising from 48 percent in 2000 to 60 percent of vehicles in 2008. Alternative fuels make up around 1.4 percent of the vehicle population, with CNG and LNG combined having the largest share at 1 percent of the vehicle population.[v] However, Table 2.4 indicates that many of the natural gas vehicles are registered to the government category, which is defined to include both government and transit districts primarily for urban transit use.

Table 2.3: Annual Percentage Distribution of Class 3 Through 8 (Medium- and Heavy-Duty) Vehicles by Fuel Type

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Vehicle Population	808,512	819,104	867,426	884,919	851,568	920,784	952,082	982,456	952,191
Diesel	47.61%	47.35%	48.82%	51.33%	55.35%	56.53%	58.46%	60.51%	60.17%
Gasoline	51.98%	52.11%	50.41%	47.85%	43.78%	42.31%	40.35%	38.29%	38.48%
Electric	0.05%	0.05%	0.07%	0.08%	0.09%	0.11%	0.11%	0.11%	0.12%
Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Natural Gas	0.17%	0.16%	0.50%	0.57%	0.63%	0.79%	0.83%	0.87%	1.02%
Propane	0.17%	0.30%	0.18%	0.15%	0.14%	0.26%	0.23%	0.21%	0.20%
Other	0.02%	0.02%	0.02%	0.02%	0.00%	0.00%	0.02%	0.01%	0.01%

Source: DMV Registration Database, October file passes from 2000 through 2008

Table 2.4 shows the distribution of medium- and heavy-duty vehicles registered to individuals, government agencies/districts, and commercial entities. Vehicles registered to government include those used in urban transit. Vehicles registered to the commercial sector include those used in intercity transit. There are noticeable differences in the percentage distribution of fuel types in these sectors. The medium- and heavy-duty vehicle population owned by individuals has been continuously declining over time with the majority of vehicles using gasoline, while the percentage fueled by diesel appears to be increasing over time. The government vehicle population has the largest percentage of alternative fuel vehicles compared to all other sectors. All three vehicle populations show an increase in the share of diesel vehicles, with gasoline vehicle share declining over time.

Table 2.4: Annual Percentage Distribution of Class 3 Through 8 (Medium- and Heavy-Duty) Vehicles by Fuel Type and Ownership Registration Type

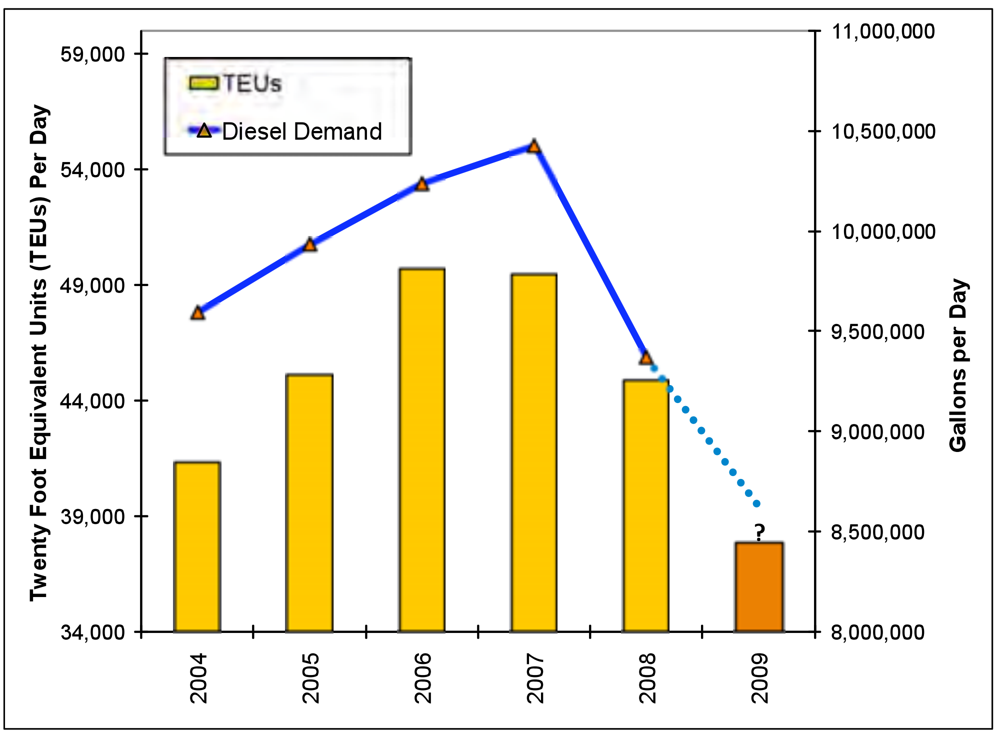
		2000	2001	2002	2003	2004	2005	2006	2007	2008
Personal	Vehicle Population	244,817	275,806	213,748	229,508	201,326	193,091	190,965	187,721	178,897
	Diesel	4.38%	9.76%	7.63%	7.73%	10.19%	11.17%	12.80%	14.34%	15.48%
	Gasoline	95.59%	90.21%	92.29%	92.23%	89.78%	88.80%	87.18%	85.64%	84.51%
	Electric	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
	Propane	0.03%	0.03%	0.06%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%
	Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Government	Vehicle Population	105,494	100,776	130,455	128,448	130,142	147,921	150,789	153,143	158,568
	Diesel	48.88%	48.42%	51.32%	53.11%	53.40%	51.14%	51.03%	51.02%	50.45%
	Gasoline	49.12%	49.74%	44.75%	42.27%	41.96%	43.70%	43.49%	43.30%	43.56%
	Electric	0.37%	0.39%	0.47%	0.57%	0.60%	0.65%	0.65%	0.62%	0.61%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	1.23%	1.07%	3.06%	3.57%	3.70%	4.11%	4.35%	4.59%	4.91%
	Propane	0.25%	0.25%	0.30%	0.39%	0.34%	0.40%	0.41%	0.42%	0.41%
	Other	0.15%	0.13%	0.10%	0.10%	0.01%	0.01%	0.06%	0.06%	0.06%
Commercial/Rental	Vehicle Population	458,201	442,522	523,223	526,963	520,100	579,772	610,328	641,592	614,726
	Diesel	70.42%	70.54%	65.02%	69.88%	73.32%	73.02%	74.58%	76.29%	75.68%
	Gasoline	29.35%	28.91%	34.71%	29.88%	26.44%	26.47%	24.92%	23.24%	23.78%
	Electric	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.04%
	Hybrids	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Natural Gas	0.01%	0.05%	0.07%	0.09%	0.11%	0.21%	0.22%	0.24%	0.31%
	Propane	0.22%	0.48%	0.20%	0.15%	0.13%	0.30%	0.25%	0.21%	0.20%
	Other	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%

Source: California Energy Commission analysis of DMV Registration Database, October file passes from 2000 through 2008
*Personal vehicles are vehicles registered to a single person.

Import Goods Movement and California Ports

A significant portion of the goods imported into the United States move through California ports. These goods are loaded onto trucks and railcars before moving to their final destinations, inside California and around the country. Containerized goods handled through the ports of Los Angeles, Long Beach, and Oakland account for 42.2 percent of all port container activity during 2008 for the continental United States.[vi] Nearly all cargo containers, referred to as twenty-foot equivalent units (TEUs), are handled at some point by either a truck or rail locomotive that is operating on diesel fuel. Therefore, the numbers of cargo containers that are imported (both full and empty) and exported through California ports are a reflection of economic activity and diesel demand in the state. Over the last couple of years, diesel fuel demand in California has demonstrated a good correlation with the total number of TEUs processed through the ports of Long Beach, Los Angeles and Oakland.[vii] Since the taxable sales figures for California typically lag several months, cargo container statistics can be examined as a potential indicator of how strong or weak diesel fuel demand may be halfway through 2009. Figure 2.11 shows the average daily numbers of TEUs processed by California's three largest container ports, along with the average daily demand for diesel fuel. As the chart shows, container activity is down significantly (23.5 percent) since 2007 when compared to the first 11 months of 2009 and down 15.7 percent compared to the average for 2008.[viii] This information is another indication that diesel fuel demand for 2009 is likely to be appreciably lower than 2008 levels.

Figure 2.11: California Ports-Container Volumes and California Diesel Demand (2004-2009)



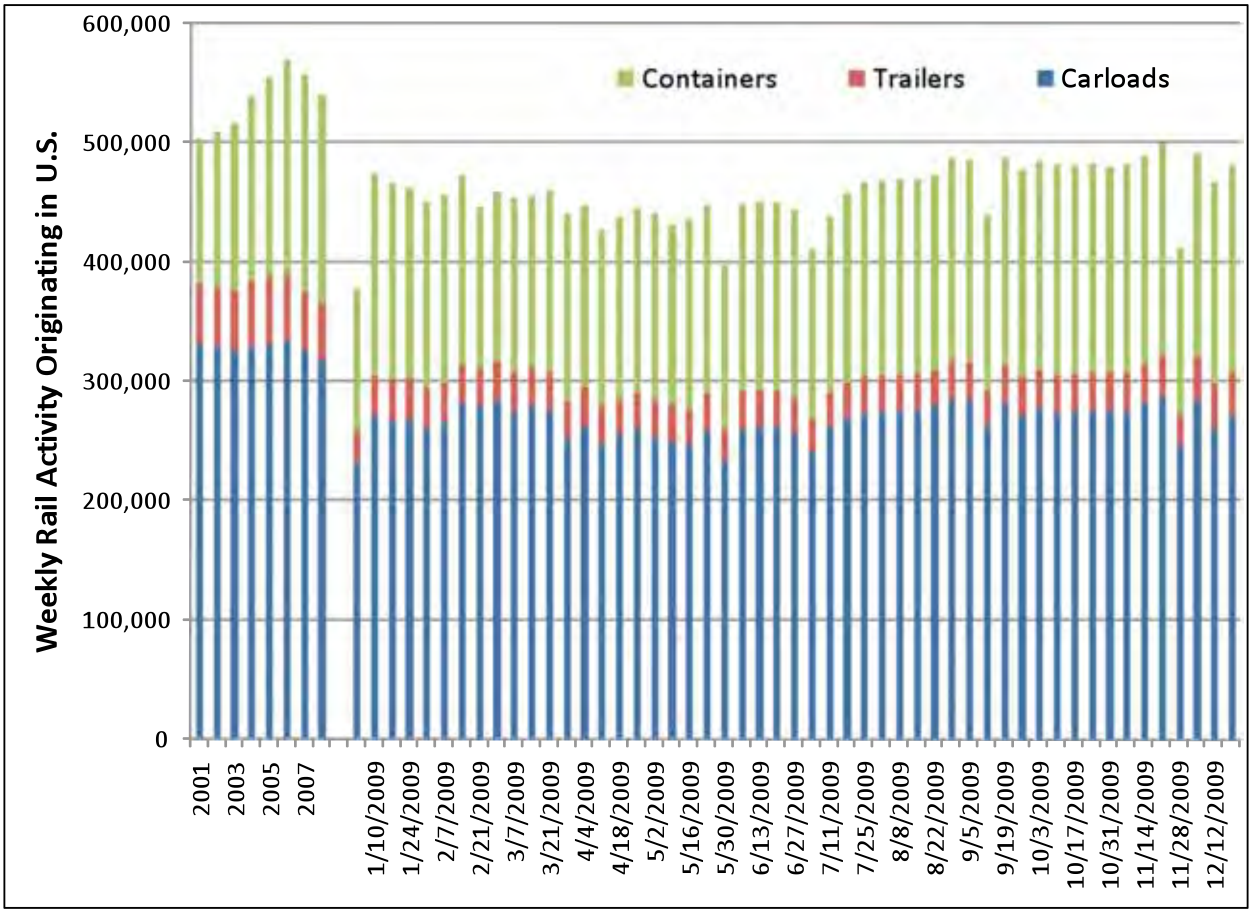
Sources: Ports of Long Beach, Los Angeles and Oakland; Board of Equalization (BOE), and Energy Commission analysis.

The U.S. Department of Commerce reports a Gross State Product (GSP) of $1,846 billion for California in 2008 [ix](Bureau of Economic Analysis, 2009). According to RAND, California imports are valued at $356 billion, which is more than 19 percent of California GSP. Most of the data on in-state freight movements primarily pertains to domestic freight and not international freight movement. Therefore, it is difficult to determine the share of total California freight movement from imported containers. However, with the growth in trade with China, California will remain a vital conduit for goods movement activities, and California ports will continue to play a major role in the national and global economy.

Rail and Truck Activity

To determine whether diesel fuel demand is beginning to recover over more recent months, staff examined other sources of information that are considered good indicators or surrogates for diesel fuel demand in the United States. One of these measures is the level of rail activity used to move freight and bulk goods throughout the country. Figure 2.12 tracks the level of rail activity for rail cars originating in the United States since January 2001. The chart shows the average weekly numbers of carloads and intermodal units (both trailers and containers). The data indicates that rail activity has declined significantly since 2006. Most recently, year-to-date activity through the week ending December 19, 2009, shows that rail carload activity is down 16.5 percent compared to the same period in 2008. Intermodal rail activity is also down 14.6 percent compared to last year, while estimated ton-miles of rail activity declined 15.5 percent compared to 2008.[x] It does not appear as though rail activity is yet rebounding from the drop in economic growth, possibly signaling that diesel demand could remain lower than 2008 volumes for the United States and California.

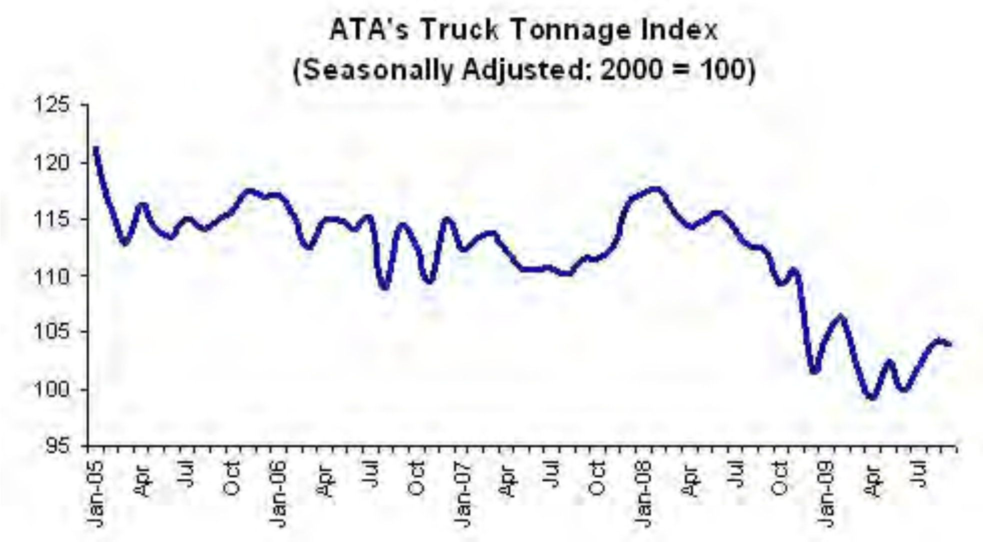
Figure 2.12: Rail Activity Originating in the United States (2001-2009)



Sources: American Association of Railroads (AAR) and Energy Commission analysis.

The American Trucking Association (ATA) tracks trucking activity in the United States. One of the instruments employed by this association is its survey of trucking companies used to assess movement of cargo and referred to as the seasonally adjusted For-Hire Truck Tonnage Index. Domestic trucking activity had been rather steady between 2005 and the first quarter of 2008. However, the rapid increase in diesel fuel prices in 2008 in conjunction with the severe downturn in the economy significantly reduced trucking activity. Figure 2.13 illustrates this point and appears to show that tonnage continues to decline, down 7.3 percent in September 2009 when compared to September 2008.[xi]

Figure 2.13: U.S. Trucking Activity – Tonnage Index (2005-2009)



Source: American Trucking Association (ATA).

Transit

Nationwide, a combination of high fuel prices and a weak economy has reduced automobile travel while increasing transit travel. Transit ridership nationwide increased to 10.7 billion trips in 2008, a 4 percent increase over 2007, continuing the upward trend in transit ridership. Ridership in California mirrored nationwide trends. Among 45 California transit agencies for which data was available from the American Public Transportation Association (APTA), ridership increased by 2.2 percent, to 1.34 billion trips, between 2007 and 2008. This compares with the staff forecast of 2.3 percent increase in ridership from 2007 to 1.53 billion trips in 2008 (a forecast year in the model) for 63 rather than 45 agencies. APTA identifies the cities with the highest transit growth rates by different transit modes, and Table 2.5 shows California cities on the APTA list.

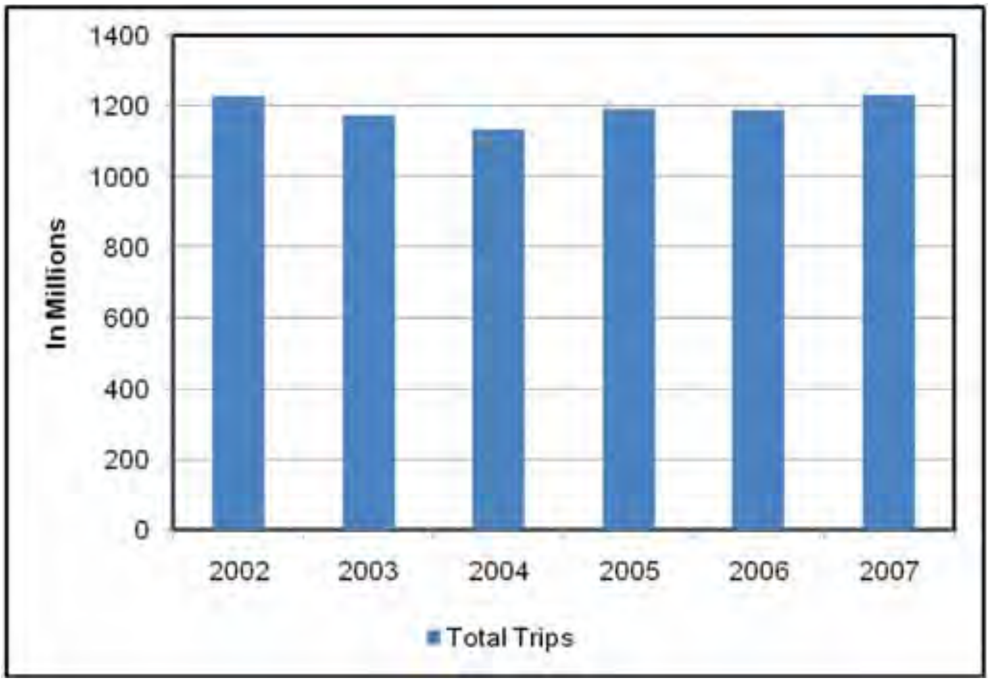
Table 2.5: 2008 California Top Transit Growth Cities by Transit Mode

City	Growth Rate (percent)	Transit Mode
Oakland	16.1	Commuter Rail
Stockton	14.7	Commuter Rail
Sacramento	14.4	Light Rail
San Diego	10.0	Bus
Los Angeles	7.7	Heavy Rail

Source: American Public Transit Association, http://www.apta.com/media/releases/090309_ridership.cfm, March 2009

In the second half of 2009 national public transportation use slipped 2.6 percent. Similarly, for the 45 California transit agencies for which data was available from APTA, ridership slipped 2.45 percent. These recent declines likely are the result of continued declines in employment, decreased transportation fuel prices, and state and local budget shortfalls[xii]. Figure 2.14 shows recent trends in total unlinked transit trips for California as reported by the Federal Transit Administration.

Figure 2.14: Transit Ridership in California

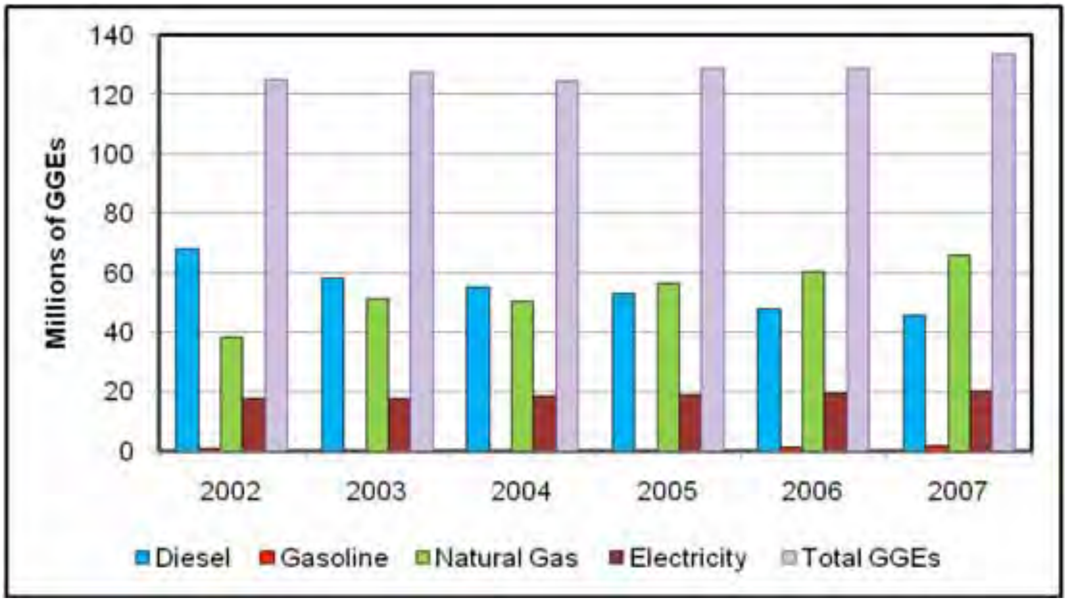


Source: Federal Transit Administration, National Transit Database, http://204.68.195.57/ntdprogram/data.htm

*Total unlinked trips, reported by 82 transit agencies in California. A few agencies have not regularly reported ridership, and the ridership has been estimated for these missing reporting years, using statewide average ridership growth rates.

Figure 2.15 shows the trend in urban transit fuel consumption, corresponding to increasing ridership. It also shows that natural gas has been replacing diesel in the transit fleet, while the rise in electricity consumption corresponds with the growth in light rail.

Figure 2.15: Urban Transit Fuel Consumption in California by Fuel Type



Source: Federal Transit Administration, National Transit Database, http://204.68.195.57/ntdprogram/data.htm*Natural gas consumption indicates the total for CNG and LNG.

The 2008 CVS reveals some patterns in the relationships between vehicle ownership, household size, miles-to-work, and transit use. Table 2.6 shows miles-to-work were highest in the Los Angeles and Sacramento regions. Transit use is highest in the San Francisco region, where transit accessibility and population density are both high, and lowest in the “rest of state,” where transit availability and population density are both low. No significant difference is observed in miles traveled to work by household size; however, households with two or three persons have the highest rate of transit use. The number of vehicles in a household has a strong relationship with both the miles traveled to work and transit use. Vehicle ownership is positively related to the mean miles traveled to work, and transit use decreases with increased number of vehicles available to the household.

Table 2.6: Miles-to-Work and Transit Use in California in 2008

Region	Mean Vehicle Miles to Work	Percent Transit Use
San Francisco	14.23	8.9%
Los Angeles	15.44	2.3%
San Diego	14.38	2.5%
Sacramento	15.29	2.7%
Rest of State	14.51	1.3%
Overall Statewide	14.87	3.6%
Household Size	**Mean Vehicle Miles to Work**	**Percent Transit Use**
1	14.94	2.0%
2	14.76	3.4%
3	14.88	3.3%
4+	14.98	2.4%
Number of Vehicles	**Mean Vehicle Miles to Work**	**Percent Transit Use**
1	12.85	4.8%
2	14.60	2.8%
3+	17.20	2.0%

Source: California Energy Commission, 2008 California Vehicle Survey

Aviation

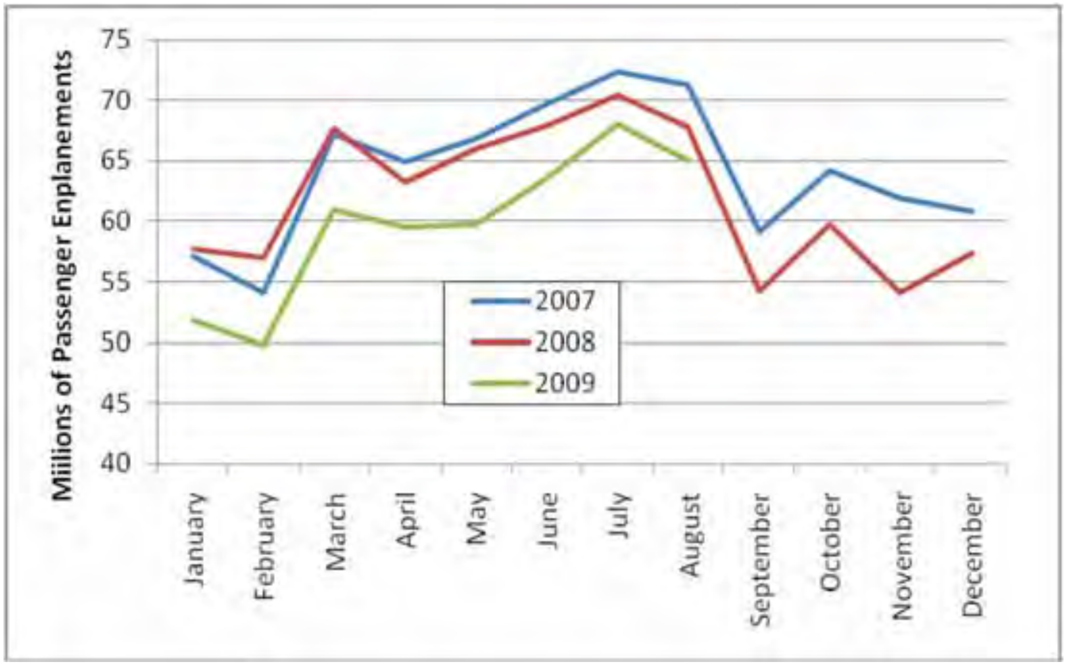
The aircraft fleets of commercial air carriers transporting passengers and cargo are powered by jet turbines and turboprops, both of which run on kerosene-type jet fuel. General (or private) aviation is increasingly dominated by jet turbine and turboprop engines, as the numbers of gasoline aircraft decrease; some general aviation aircraft are air taxis transporting passengers for hire. Wide-body jets of the 1970s and 1980s have largely been replaced in domestic service but persist in international passenger operation and air cargo. Narrow-body jets such as the Boeing 737 and Airbus 240 have come to dominate domestic passenger travel. The next generation of lighter and more efficient aircraft, such as the Boeing 787, is in production and may provide up to 25 percent reduction in fuel use per passenger mile.

Airlines have responded to fuel price increases of recent years by reducing both the number of empty seats and the number of flights. In response to decreased demand, airlines have financial reasons for taking the least efficient aircraft out of service. The converse is also true, that as demand increases the newest and generally most efficient of remaining aircraft is placed back into service. As a result the overall rate of fuel use per passenger mile may increase in the short term with an increase in demand.

The growth of air cargo service, measured in ton miles, has come from increased Internet commerce, the growth of the package industry in general, and the development of niches such as perishable soft fruits, seafood, and prototype electronics. Adding to these growth drivers is the growth in Pacific Rim commerce, which funnels an increasing fraction of the nation’s imports into and through California airports. Additionally, greater amounts of cargo will likely be transported by air freight-only carriers due to the requirement that by 2010 100 percent of cargo must be screened when placed into passenger aircrafts.

Airline activity is usually a good barometer for jet fuel demand. The United States Bureau of Transportation Statistics compiles information from airline companies operating in the United States. One of the better measures of air activity is the number of people boarding flights that originate in the United States and are destined for locations both domestic and international. Referred to as passenger enplanements, the most recent data for 2009 indicate that passenger activity continues to be lower than the preceding two years. Figure 2.16 illustrates that airline passenger activity has not yet begun to recover from a steady decline from 2007. For the first eight months of 2009, total passenger enplanements are down 7.6 percent compared to the same period in 2008.[xiii]

Figure 2.16: U.S. Airline Passenger Enplanements (2007-2009)



Source: United States Bureau of Transportation Statistics.

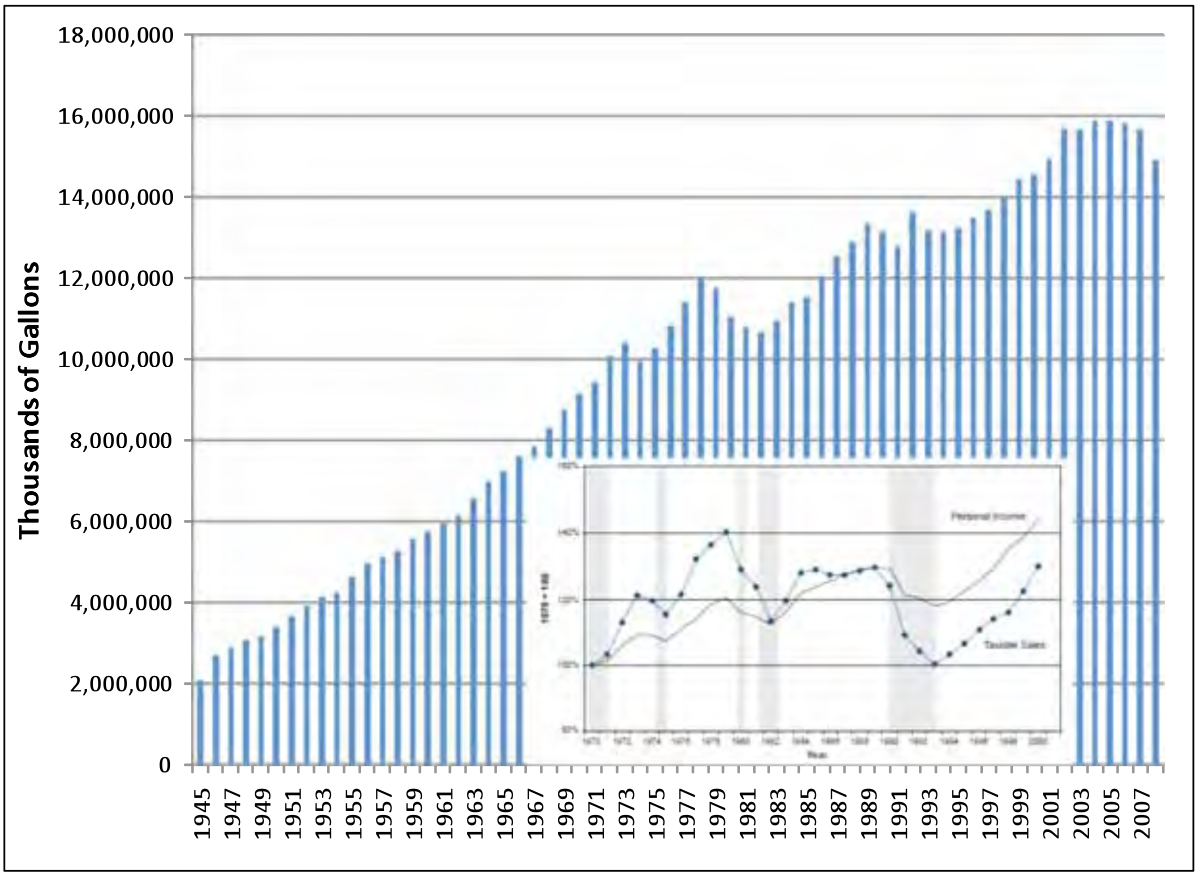
Recent Demand for California Transportation Fuels

Demand for traditional petroleum-based transportation fuels (gasoline, diesel, and jet fuel) has recently declined as a consequence of several factors. Lower demand levels reduce the need to import blending components and finished petroleum products that augment local refinery production supply.

Gasoline Demand

Over the last several decades, there have been occasional stretches when gasoline demand declined from one year to the next. It has been unusual that California has experienced any periods when gasoline demand declined for multiple consecutive years. The longest sustained demand decline was from 1978 through 1982. As expected, these downturns in gasoline demand appear to be closely associated with California's periods of recession that have resulted in lower levels of personal income.[xiv] Figure 2.17 depicts how California's gasoline demand has grown since the end of World War II, rising from 2.06 billion gallons in 1945 to a peak of 15.91 billion gallons in 2004.

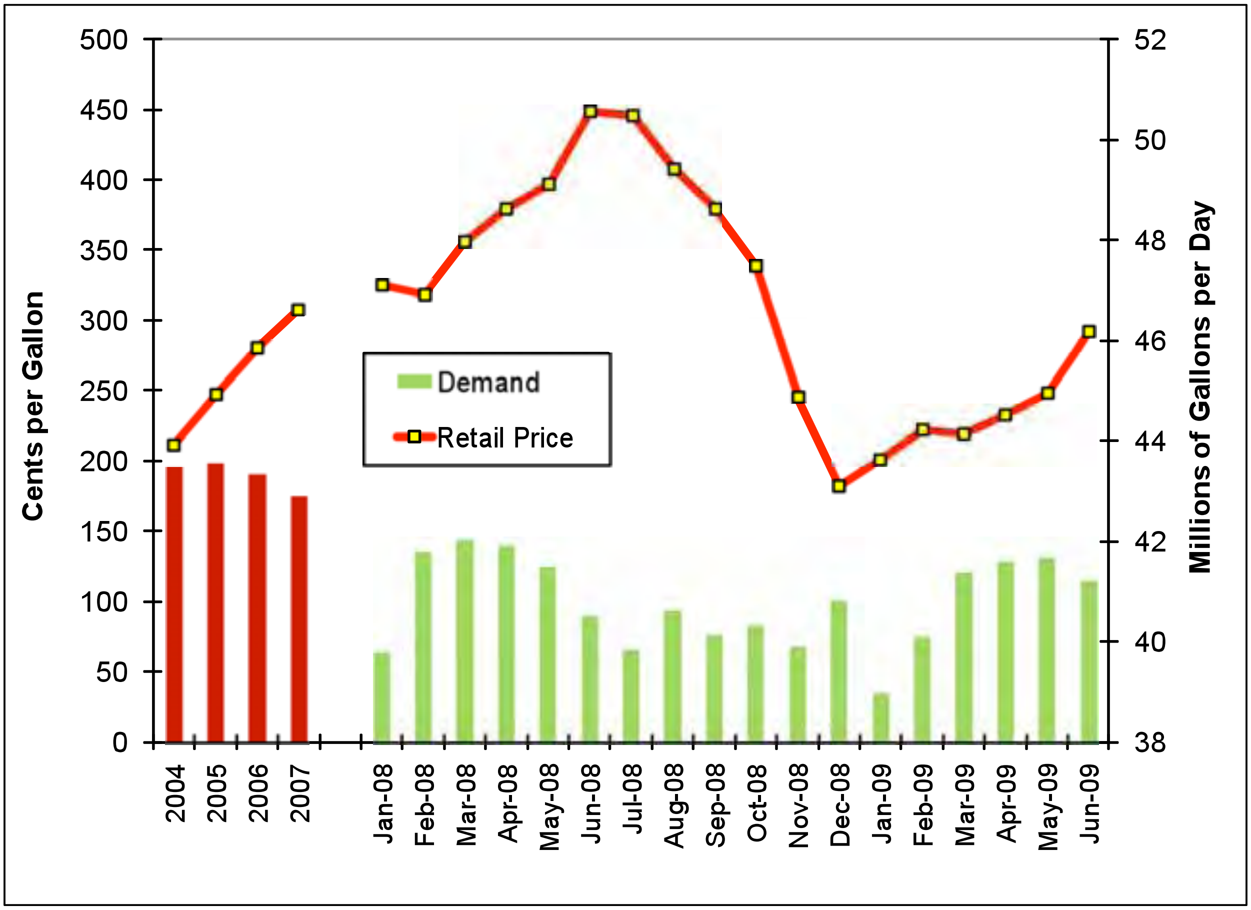
Figure 2.17: California Gasoline Demand and Recessions (1945-2008)



Sources: Federal Highway Administration, California State Board of Equalization, and Energy Commission analysis.

Staff has recently analyzed the taxable gasoline sales data compiled by BOE. Adjustments were mainly made to compensate for large audits that were reported as "sales" during a single month but were in fact a compilation of new or rectified accounting records that took place over several months or years. This new analysis has resulted in slight revisions to the BOE taxable gasoline sales figures that are available at the BOE website.[xv] Figure 2.18 shows the total annual gasoline demand and retail prices for 2004 through 2007 and monthly figures thereafter. California average daily gasoline demand for the first six months of 2009 is 1.0 percent lower compared to the same period in 2008, continuing a declining trend since 2004. In fact, over the last 12 months (July 2008 through June 2009) gasoline demand is down 3.4 percent compared to the previous 12-month period (July 2007 through June 2008).[xvi]

Figure 2.18: California Average Daily Gasoline Demand and Price (2004-2009)



Sources: California State Board of Equalization and Energy Commission analysis.

California Historical Relationship Between Gasoline Use, Vehicles, and Registered Drivers

The following discussion focuses on California's historic gasoline demand since 2000. From 2000 to 2008 gasoline demand in California grew at 0.32 percent per year while California's total population grew at a faster pace, 1.37 percent per year (see Table 2.7). As a result, per capita gasoline demand in California has been declining at annual rate of 1.04 percent. The total population growth has been the primary contributor to the per capita decline in gasoline demand. However, it is important to note that not every person in California consumes gasoline so a better representation of demand may be warranted. Staff looked at per vehicle demand and per driver demand as two alternative trends to per capita gasoline demand.

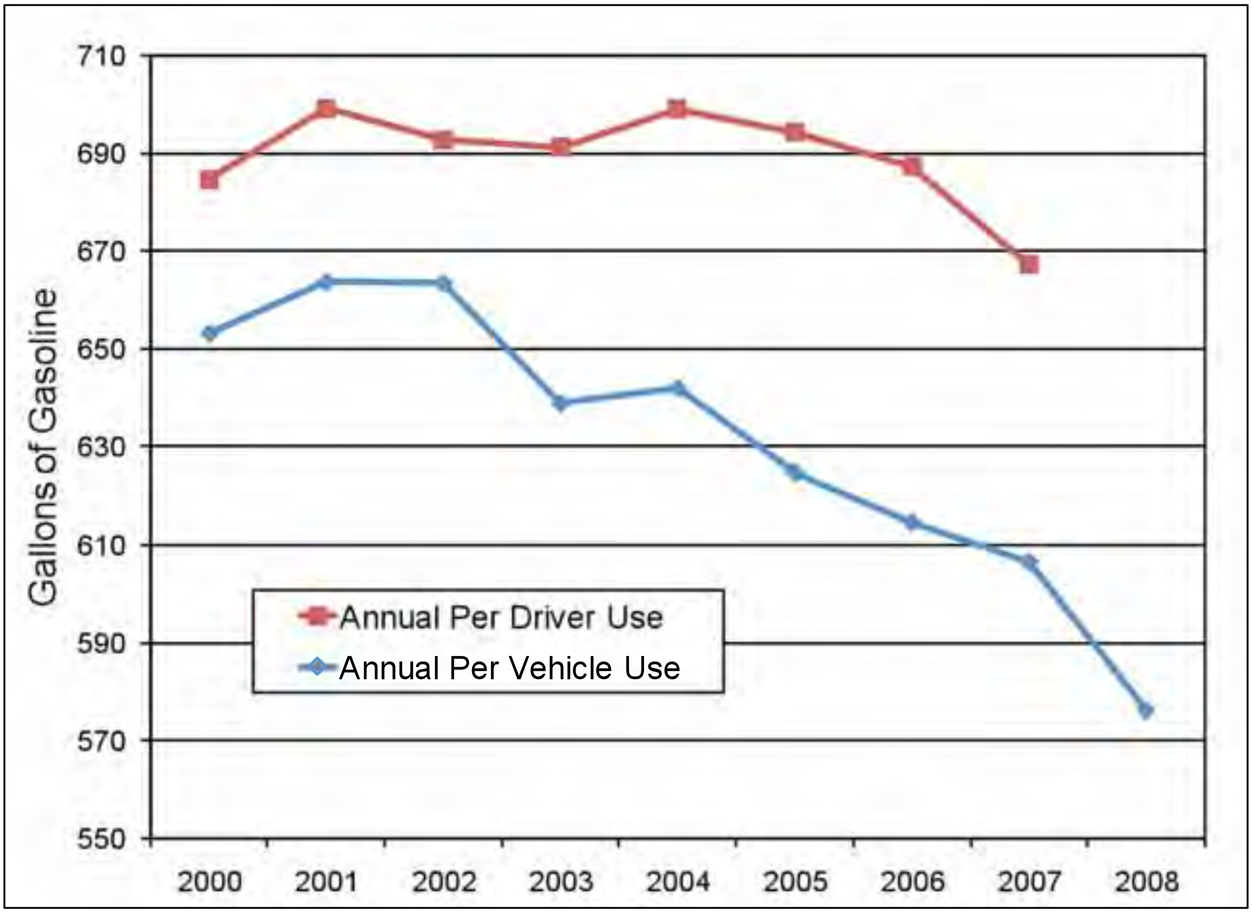
Table 2.7: California Historical Population and Gasoline Demand (2000 – 2008)

Year	California Population	Historic Annual Gasoline Demand	Annual Per Capita Demand	Annual Registered Gasoline Vehicles	Annual Per Vehicle Demand	Registered CA Drivers	California Population Without Driver's License	Annual Per Driver Demand
2000	34,152,028	14,544,627,116	425.88	22,268,785	653.14	21,243,939	12,908,089	684.65
2001	34,747,465	15,117,143,010	435.06	22,779,246	663.64	21,623,793	13,123,672	699.10
2002	35,358,330	15,513,415,849	438.75	23,384,639	663.40	22,394,800	12,963,530	692.72
2003	35,926,021	15,661,671,712	435.94	24,516,071	638.83	22,657,288	13,268,733	691.24
2004	36,438,137	15,909,201,916	436.61	24,785,578	641.87	22,761,088	13,677,049	698.96
2005	36,881,561	15,894,985,843	430.97	25,440,904	624.78	22,895,965	13,985,596	694.23
2006	37,279,133	15,821,102,372	424.40	25,741,051	614.63	23,021,279	14,257,854	687.24
2007	37,678,033	15,658,306,800	415.58	25,815,758	606.54	23,467,452	14,210,581	667.24
2008	38,088,340	14,917,674,124	391.66	25,890,465	576.18			
Average Annual Growth Rate								
2000 to 2007	**1.41%**	**1.06%**	**-0.35%**	**2.13%**	**-1.05%**	**1.43%**	**1.38%**	**-0.37%**
2000 to 2008	**1.37%**	**0.32%**	**-1.04%**	**1.90%**	**-1.55%**			

Source: California Energy Commission analysis of BOE, DOF, and DMV data.

From 2000 to 2007 per vehicle demand declined at 1.05 percent annually, a much faster rate than per capita gasoline over the same period 0.35 percent annually. (See Figure 2.19.) This is due to the marked increase in vehicles in California over this period of 15.9 percent. Consequently the large decline in per vehicle demand is really a reflection of the increased number of vehicles on the road and does not provide insights into the driving patterns of Californians. Over the same period, per driver gasoline demand has declined only 2.5 percent or 0.37 percent annually. This is a much smaller decline than per capita or per vehicle gasoline demand and better represented the muted response of gasoline demand since 2000. Still, overall gasoline demand has been declined significantly as the economic conditions worsened in California.

Figure 2.19: California Historical Gasoline Use Per Driver and Vehicle (2000-2008)

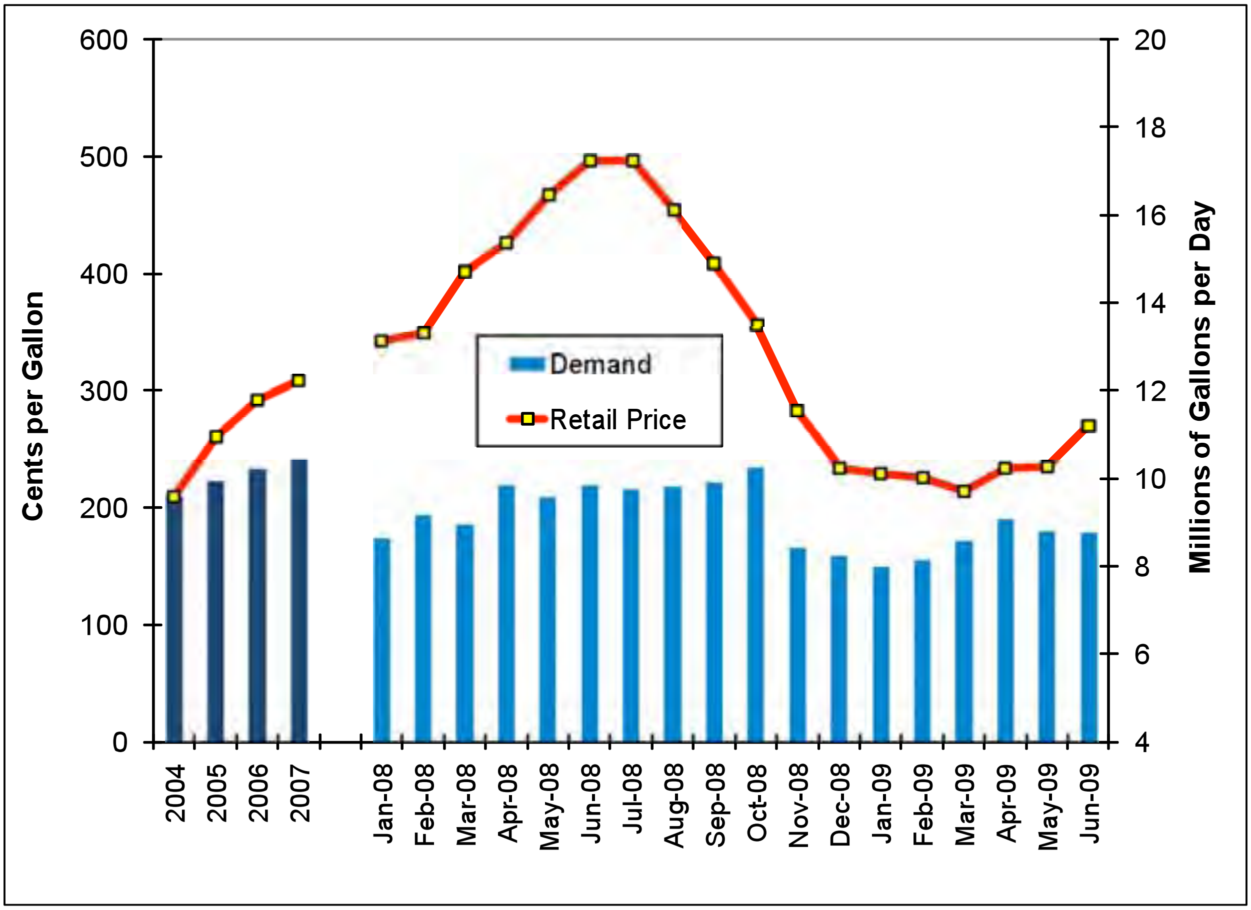


Sources: Energy Commission analysis of BOE, DOF, and DMV data.

Diesel Fuel Demand

As was the case with gasoline, staff adjusted monthly diesel fuel sales figures to include additional volumes of red dye diesel fuel that are not included in BOE taxable sales figures since the first sale of diesel fuel intended for use in an exempt manner is not a taxable event. However, to better assess monthly demand for diesel fuel, it is appropriate to include these red dye volumes. Figure 2.20 shows the total annual diesel fuel demand and retail prices for 2004 through 2007 and monthly figures thereafter. California average daily diesel fuel demand for the first six months of 2009 is 8.4 percent lower compared to the same period in 2008, continuing a declining trend since 2007. Over the last 12 months (July 2008 through June 2009) diesel fuel demand is down 10.1 percent compared to the previous 12-month period (July 2007 through June 2008).[xvii]

Figure 2.20: California Average Daily Diesel Demand and Price (2004-2009)

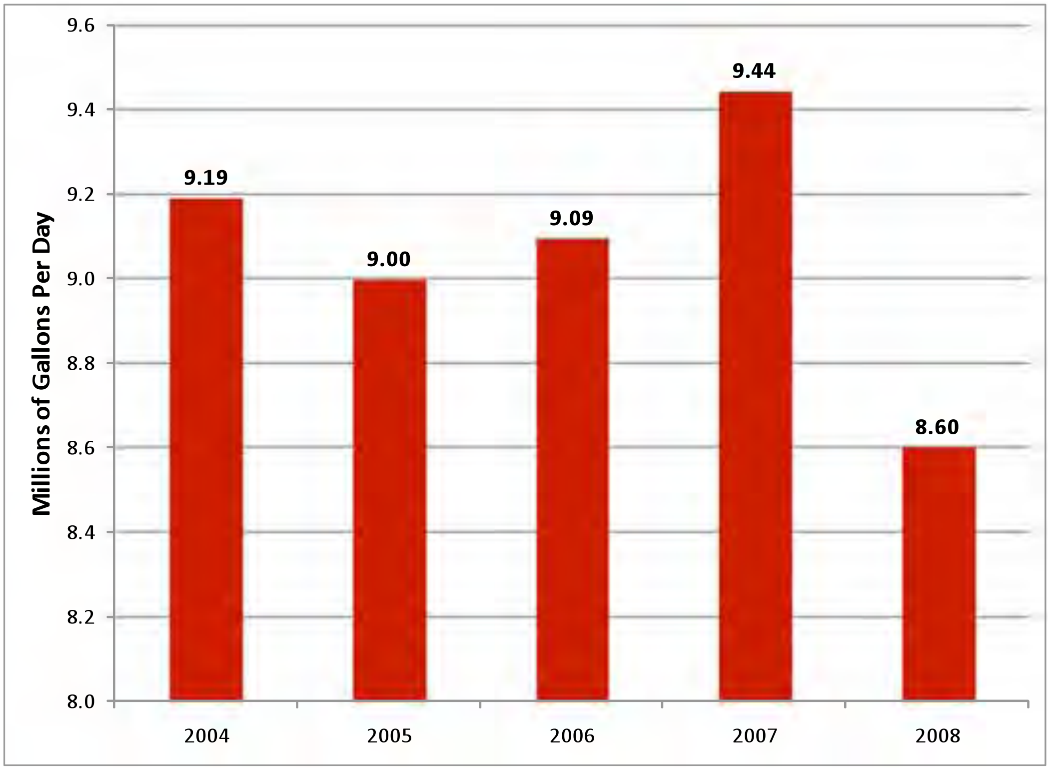


Sources: California State Board of Equalization and Energy Commission analysis.

Jet Fuel Demand

The third type of traditional petroleum-based transportation fuel is commercial jet fuel or Jet A. California refiners also produce limited quantities of military grade jet fuel, referred to as JP-5 and JP-8. For examining recent and forecasted jet fuel demand quantities and trends, only commercial jet fuel was included. Recent demand trends for jet fuel are similar to diesel fuel and reflect an overall downturn in the domestic and California economies. After rising 5 percent between 2005 and 2007, California jet fuel demand declined 8.9 percent in 2008 compared to the previous year. Figure 2.21 shows the annual demand for commercial jet fuel in California from 2004 through 2008.

Figure 2.21: California Commercial Jet Fuel (Jet A) Demand (2004-2008)



Sources: Petroleum Industry Information Reporting Act data and Energy Commission analysis.

Transportation Demand Forecasts

Approach to Forecasting and Assumptions

The transportation demand forecasts prepared for this staff draft report encompass four primary transportation sectors.

- Commercial and residential light-duty vehicles (under 10,000 pounds GVWR)
- Medium- and heavy-duty transit vehicles, including rail (over 10,000 pounds GVWR)
- Medium- and heavy-duty freight vehicles, including rail
- Commercial aviation

Each of these sectors is associated with a distinct forecasting model which estimates the demands for that individual transportation sector. The California Conventional Alternative Fuel Response Simulator (CALCARS), Freight, Transit, and Aviation models represent each of the corresponding transportation sectors. Appendix A provides a description of these models and their updates.

Staff has developed forecasts over a range of fuel prices used in forecasting transportation energy demand in California. Appendix B details all fuel price cases developed for use in the forecasts. Additionally, economic and demographic projections from DOF and Moody's Economy.com were extended to 2030 to cover the forecast period. (Survey responses and information represent the forecasted period for California.) As with past transportation fuel demand forecasts, K.G. Duleep of ICF International provided historic and projected vehicle characteristics used in the CALCARS model. Appendix A briefly discusses the vehicle characteristics included in the model evaluation.

In 2004, ARB adopted the California GHG standard for light-duty vehicles (Assembly Bill 1493, Pavley, Chapter 200, Statutes of 2002). The standard requires a gradual reduction of GHG equivalent emissions beginning in 2009, which by 2016 results in approximately a 30 percent reduction in emissions per mile for the average new vehicle as compared to today's new vehicles. The levels of fuel economy used in this report for light-duty vehicle demand cases considering the GHG standard are based on the levels of average fuel economy improvement, which could allow compliance with the standard, as well as the ZEV mandate.

Staff updated the CALCARS model with the 2008 CVS results for the final 2009 IEPR forecast. The survey, which is described briefly on p. 33, obtained information on respondents' attitudes and preferences regarding several alternative fuel technologies, including hybrids, plug-in hybrids, full electric vehicles, flex-fuel vehicles, and CNG vehicles. This data enabled staff to forecast demand across the breadth of transportation fuels, not just conventional petroleum fuels.

There are a number of infrastructure and fuel station availability assumptions which play an important role in the forecasting of the alternative fuels. For high ethanol blends, those reaching 85 percent by volume (E85), the number of fuel stations available to fuel vehicles is an important factor since flex fuel vehicles capable of fueling with high ethanol blends continue to increase in California's vehicle population. For both price cases, staff assumed the number of E85 dispensers available to the public would reach 630 by 2030 under a "business as usual" scenario of no regulations mandating greater use of ethanol beyond E10 levels. However, as discussed in greater detail in Chapter 3, both federal (Renewable Fuel Standard 2) and state (Low Carbon Fuel Standard) regulations are expected to mandate significantly greater quantities of ethanol in California's gasoline such that more than 2 billion gallons of E85 are forecast to meet these requirements by 2015. The number of E85 retail dispensers required to meet these higher demands are a minimum of nearly 5,000 by 2022.

In the case of transportation electricity, there are significant vehicle technology and infrastructure barriers that need to be overcome for widespread use of plug-in hybrids and full electric vehicles to become a reality. For the most part, staff assumed that home would be the primary location for charging these vehicles and that 88 percent of the time they will be charged during off-peak hours to take advantage of the best electricity rates from utilities. Additionally, staff estimates overall demand for transportation electricity will remain below 2 percent of overall statewide electricity demand in 2020 and therefore would not require additional peak generation capacity. For natural gas, staff assumed the current trends of transit consumption would continue, light-duty vehicles would continue to be available for consumer purchase, and that fueling infrastructure does not constrain consumption.

Transportation Fuel Demand Forecasts

In general, the early years of the demand forecast represent a recovery from the current recessionary economic conditions. Because the economic and demographic projections used in these forecasts indicate the return of reasonably healthy economic growth and steady population growth, the trends for the freight and aviation sectors tend to resume historical patterns of increases in fuel demand. Gasoline demand in the light-duty sector, however, is more heavily influenced by the introduction of competing technologies, efficiency improvements, and by higher projected fuel prices. As a result, the forecasted gasoline demand tends to decline in later years.

Gasoline Demand Forecast

Table 2.8 reports the light-duty gasoline consumption forecast in California, and Table 2.9 and Figure 2.22 show total forecasted gasoline consumption. Between 2007 and 2030, total gasoline consumption in California falls by 13.3 percent in the low demand case as increased efficiency, continued fleet hybridization and dieselization, and the introduction of alternative fuels reduce gasoline demand. In the high demand case, the recovering economy and lower fuel prices lead to a gasoline demand peak in 2014 before falling to 14.3 billion gallons in 2030, 8.1 percent below 2007 levels.

Table 2.8: California Light-Duty Vehicle Gasoline Demand Forecast (Gallons)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	15,404,295,151		15,404,295,143	
2010	14,733,953,378	-4.35%	15,137,294,752	-1.73%
2015	15,422,350,389	4.67%	16,157,839,911	6.74%
2020	14,256,301,112	-7.56%	15,096,012,667	-6.57%
2025	13,518,539,454	-5.17%	14,278,189,729	-5.42%
2030	13,415,756,227	-0.76%	14,161,923,909	-0.81%
Average Annual Growth Rate	-0.60%		-0.36%	

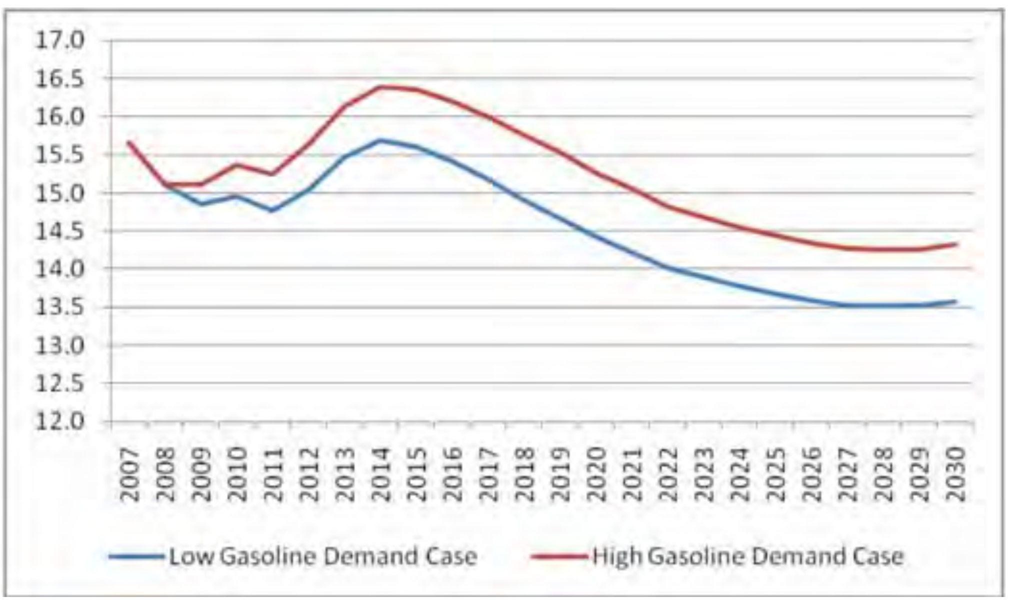
Source: California Energy Commission

Table 2.9: Total California Gasoline Demand Forecast (Gallons)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	15,658,237,951		15,658,237,943	
2010	14,956,643,778	-4.48%	15,360,225,152	-1.90%
2015	15,610,337,189	4.37%	16,346,946,711	6.42%
2020	14,421,323,112	-7.62%	15,262,764,667	-6.63%
2025	13,676,011,854	-5.17%	14,437,962,129	-5.40%
2030	13,572,105,827	-0.76%	14,321,133,509	-0.81%
Average Annual Growth Rate	-0.62%		-0.39%	

Source: California Energy Commission

Figure 2.22: Total California Gasoline Demand Forecast (Billions of Gallons)



Source: California Energy Commission

Diesel Demand Forecast

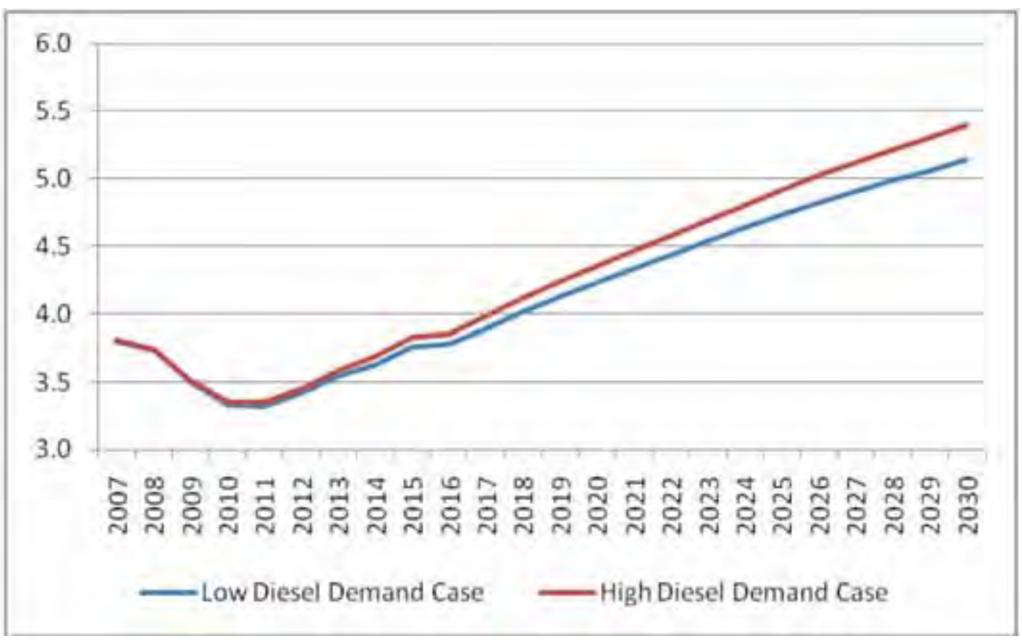
The diesel demand forecast represents four primary areas: truck and rail freight goods movement, residential and commercial light-duty vehicle transportation, urban and intercity public transit, and off-road use of diesel (mostly in construction and agriculture). Of these four sectors, goods movement is by far the most significant, representing over 83 percent of all consumption in the 2007. Table 2.10 and Figure 2.23 show the total California diesel demand forecast. Between 2007 and 2030, total diesel demand is forecast to increase by 35 percent in the low demand case and 41 percent in the high demand case.

Table 2.10: California Diesel Demand Forecast (Gallons)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	3,805,139,662		3,805,866,881	
2010	3,332,865,763	-12.41%	3,354,477,740	-11.86%
2015	3,760,153,105	12.82%	3,829,527,177	14.16%
2020	4,231,080,051	12.52%	4,353,254,456	13.68%
2025	4,732,020,454	11.84%	4,918,909,775	12.99%
2030	5,138,484,333	8.59%	5,399,294,401	9.77%
Average Annual Growth Rate	1.31%		1.53%	

Source: California Energy Commission

Figure 2.23: California Diesel Demand Forecast (Billions of Gallons)



Source: California Energy Commission

Unadjusted High Ethanol Blends (E85) Demand Forecast

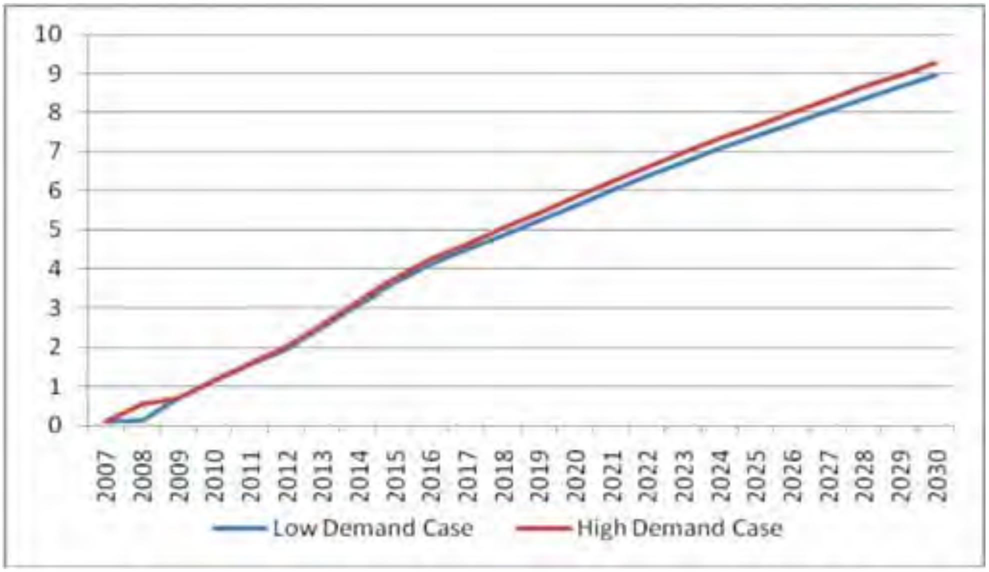
The unadjusted high ethanol blend (ethanol blend with gasoline to 85 percent by volume, or E85) demand forecast represents residential and commercial light-duty vehicle transportation consumption of E85. The high overall rate of increase for this fuel is directly related to the number of fueling stations available within California. The forecasted number of stations increases from 4 stations in 2007 to 630 stations in 2030. Table 2.11 and Figure 2.24 show the total unadjusted California E85 demand forecast. These results are considered unadjusted because they do not comply with the latest National Renewable Fuels Standards and will be adjusted in Chapter 3.

Table 2.11: California Unadjusted High Ethanol Blend (E85) Demand Forecast (Gallons)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	94,032		94,032	
2010	1,136,954	1109.11%	1,162,773	1136.57%
2015	3,620,556	218.44%	3,730,763	220.85%
2020	5,616,716	55.13%	5,834,246	56.38%
2025	7,395,734	31.67%	7,661,638	31.32%
2030	8,942,940	20.92%	9,259,782	20.86%
Average Annual Growth Rate	21.90%		22.09%	

Source: California Energy Commission

Figure 2.24: California Unadjusted High Ethanol Blend (E85) Demand Forecast (Millions of Gallons)



Source: California Energy Commission

Transportation Electricity Demand Forecast

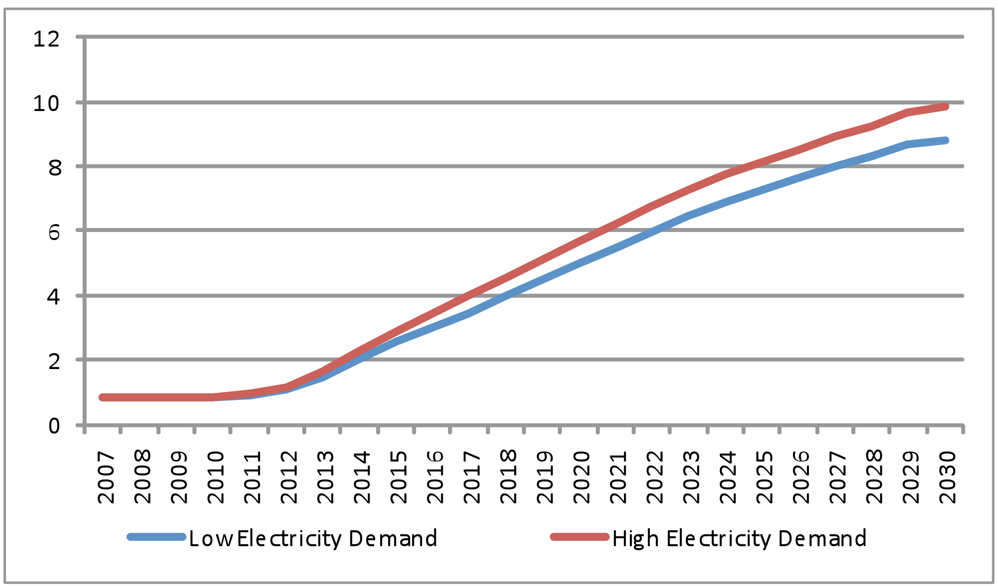
The transportation electricity demand forecast represents three primary areas: residential and commercial light-duty vehicle transportation and urban public transit. The majority of early electricity demand for the transportation sector is attributable to electric rail in urban transit. Through the latter years of the forecast, plug-in hybrid and full electric vehicles consume a larger portion of the forecasted transportation electricity, over 90 percent of demand in both cases by 2030. The Low Demand Case has lower oil prices, higher electricity prices and lower numbers of electric vehicles when compared to the High Demand Case. Table 2.12 and Figure 2.25 show the total California transportation electricity demand forecast.

Table 2.12: California Transportation Electricity Demand Forecast (GWhs)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	835		835	
2010	835	0.04%	856	2.56%
2015	2,536	203.65%	2,869	235.15%
2020	4,958	95.54%	5,656	97.12%
2025	7,265	46.53%	8,128	43.73%
2030	8,808	21.24%	9,838	21.04%
Average Annual Growth Rate	10.79%		11.32%	

Source: California Energy Commission

Figure 2.25: California Transportation Electricity Demand Forecast (Thousands of GWhs)



Source: California Energy Commission

Transportation Natural Gas Demand Forecast

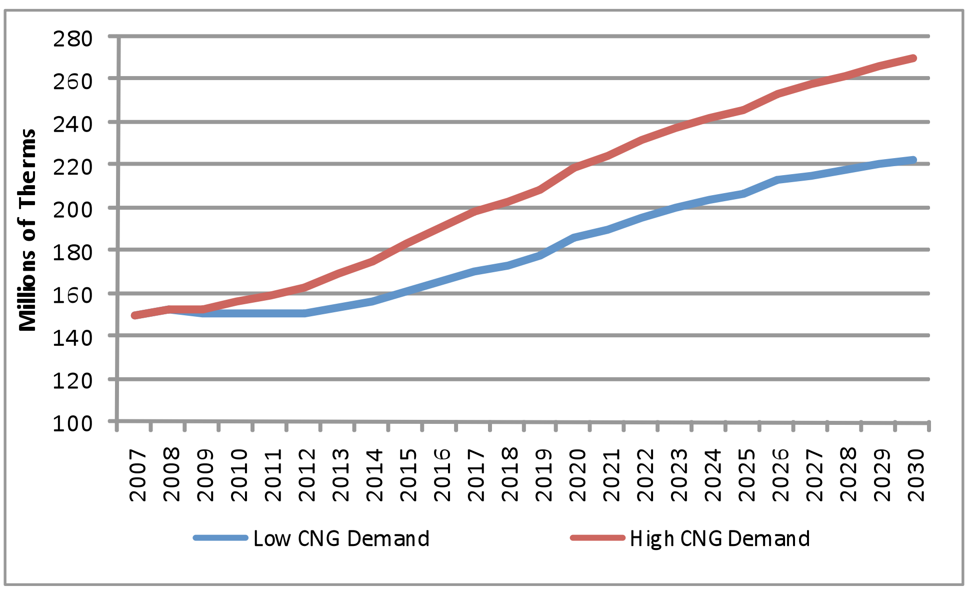
The transportation natural gas demand forecast represents three primary areas: residential and commercial light-duty vehicle transportation and urban public transit. Of these sectors, urban public transit is most significant, representing over 90 percent of all consumption in 2007. However, by 2030 light-duty natural gas vehicles gained about 30 percent of the market in both demand cases. The Low Demand Case has lower oil prices, higher natural gas prices and lower numbers of natural gas vehicles when compared to the High Demand Case. Table 2.13 and Figure 2.26 show the total California natural gas transportation demand forecast.

Table 2.13: California Transportation Natural Gas Demand Forecast (Therms)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	150,128,357		150,128,360	
2010	150,726,790	0.40%	156,260,884	4.08%
2015	161,114,904	6.89%	183,245,428	17.27%
2020	186,642,520	15.84%	219,427,462	19.75%
2025	207,368,777	11.10%	245,982,368	12.10%
2030	222,884,810	7.48%	270,313,465	9.89%
Average Annual Growth Rate	1.73%		2.59%	

Source: California Energy Commission

Figure 2.26: California Transportation Natural Gas Demand Forecast (Millions of Therms)



Source: California Energy Commission

Jet Fuel Demand Forecast

Since jet fuel is formulated to national and international standards, jet fuel demand forecasts do not take into account California GHG standards but do incorporate high and low jet fuel price scenarios as well as two aviation fuel efficiency forecast cases. Assumptions of high jet fuel prices and fuel efficiency imputed from United States Federal Aviation Administration (FAA) projections generate the low demand case. Low jet fuel prices and the FAA fuel efficiency performance targets generate the high jet fuel demand case. Staff did not attempt to project military jet fuel use, so military consumption is excluded from the forecast. Table 2.14 and Figure 2.27 show the low and high jet fuel demand cases.

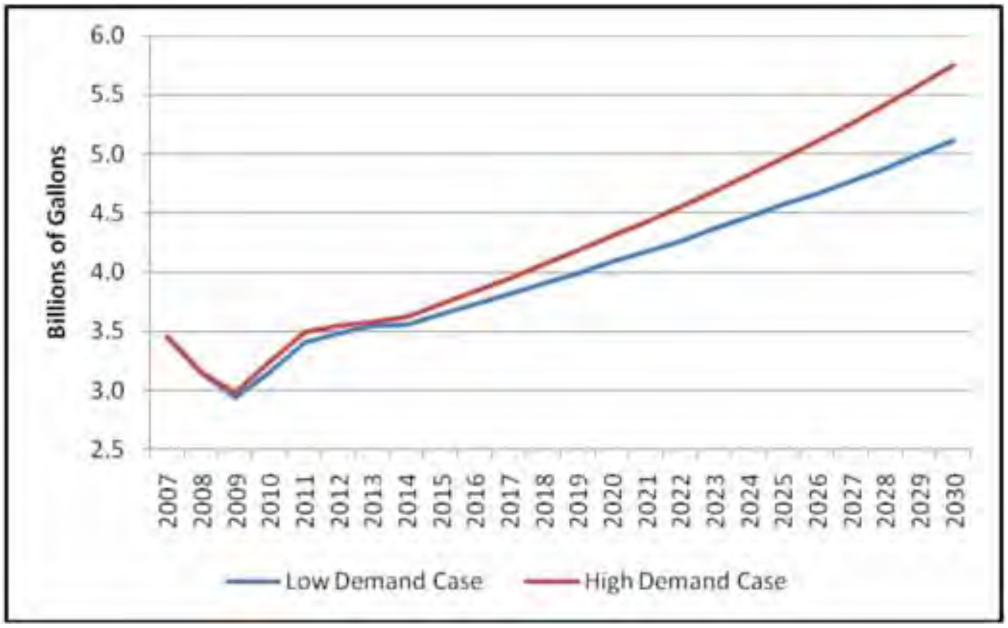
Between 2007 and 2030 staff expects that jet fuel demand in California will increase by 51.2 percent to 5.12 billion gallons in the low demand case and 67.2 percent to 5.75 billion gallons in the high demand case.

Table 2.14: California Jet Fuel Demand Forecast (Gallons)

Year	Low Demand Case	Percentage Change From the Previous Value	High Demand Case	Percentage Change From the Previous Value
2007	3,446,593,006		3,446,593,006	
2010	3,156,383,966	-8.42%	3,247,229,634	-5.78%
2015	3,641,014,703	15.35%	3,733,969,879	14.99%
2020	4,081,988,183	12.11%	4,302,667,349	15.23%
2025	4,569,339,667	11.94%	4,964,917,236	15.39%
2030	5,115,783,871	11.96%	5,748,285,636	15.78%
Average Annual Growth Rate	1.73%		2.25%	

Source: California Energy Commission

Figure 2.27: California Jet Fuel Demand Forecast



Source: California Energy Commission

CHAPTER 3: Renewable and Alternative Fuels

Use of renewable and other alternative fuels in the United States and California is expected to continue growing, primarily as a consequence of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption. However, there are several unresolved issues that have yet to be addressed regarding adequacy of both additional supplies and the requisite infrastructure to receive and distribute increased quantities of ethanol and biodiesel to California consumers. In some circumstances, different federal and state policies may counteract trends that could imperil attainment of their stated goals. Likewise, there are numerous challenges to developing adequate vehicle production and sales, refueling infrastructure, and technical standards that would enable increased use of natural gas, electric, and other alternative fuels in transportation.

This chapter will provide historical information, regulatory context, supply assessments, and identification of infrastructure barriers that could endanger adequacy of transportation fuel supplies for California motorists and businesses. Available time and resources dictate that staff focuses on those issues that appear to have the most pressing near-term consequences, namely the intersection of complex state and federal renewable fuel rules that prescribe percentages and volumes of renewable fuels consumed, particularly ethanol. Other fuels will be discussed, but with the understanding that the time, dialogue, and research needed to fully quantify their contributions to petroleum and carbon reduction, and the barriers to their adoption, are limited. However, staff is committed to developing these analyses in future work as resources and time permit and seeks an open and ongoing discussion with stakeholders to work to that end.

Key Questions

Renewable Fuels

How much additional ethanol and biodiesel will be required in California over the next several years?

Is there enough domestic production capacity available to meet this increase in renewable fuel demand?

When will ethanol demand in California exceed the ethanol “blend wall” of 10 percent by volume?

Can California move to a 15 percent ethanol limit in gasoline over the near to mid-term?

If not, what type of E85 infrastructure (vehicles and retail outlets) and timing would be required to accommodate ethanol volumes above the blend wall?

Will the LCFS necessitate a change in the type of ethanol required to achieve compliance with the new standard?

What will be the source of this other type of ethanol, and will there be enough supply available to meet California’s estimated demand?

If so, what type of infrastructure would be needed, and is that import capacity currently in place?

If not, how much time would be required to construct new capabilities and modify existing infrastructure in time to meet anticipated changes?

Will substantial increases in demand for ethanol place an undue burden on agriculture?

Other Alternative Fuels

How much natural gas, electricity, and hydrogen will be required to power natural gas-powered vehicles, full electric and plug-in hybrid electric vehicles, and fuel cell vehicles in California over the mid- to long-term future? Are these energy sources going to be available in sufficient supply and at a price attractive to consumers?

What are the barriers to increased use of natural gas, electricity, and hydrogen in transportation applications?

What is required to stimulate the production and sale of increasing numbers of natural gas, electric, and fuel cell vehicles?

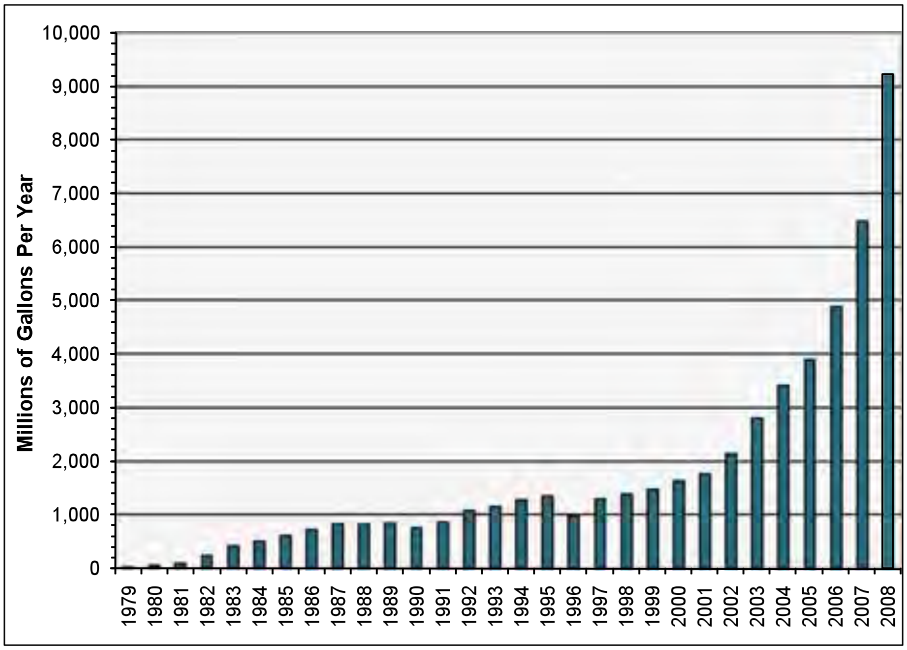
What are the options for retail refueling infrastructure needed to meet alternative fuel demand and how can the development of additional refueling facilities be stimulated? What are the options for home refueling of natural gas and electric vehicles, and what steps are needed to promote their adoption?

What standards, specifications, and other technical conventions need to be developed to promote alternative fuel vehicle sales and energy use?

Ethanol Overview

Ethanol (normally referred to as denatured fuel ethanol) has a long history as a transportation fuel in the United States. The Ford Model T, first manufactured in 1908, was designed with an engine that operated on gasoline, kerosene, or ethanol.[xviii] The use of ethanol as a motor vehicle fuel was modest from the early 1900s through the late 1930s. Declining prices of gasoline, relative to ethanol, decreased ethanol's role in transportation fuel for the next several decades until the oil price shocks of the 1970s spurred government action and intervention.[xix] Federal assistance in the form of tax credits and loan guarantees resulted in a resurgence of the U.S. ethanol industry from "practically zero" in 1978 to more than 210 million gallons by 1982.[xx,xxi] Figure 3.1 shows the annual progression of ethanol production in the United States between 1979 and 2008.

Figure 3.1: U.S. Ethanol Production 1979-2008

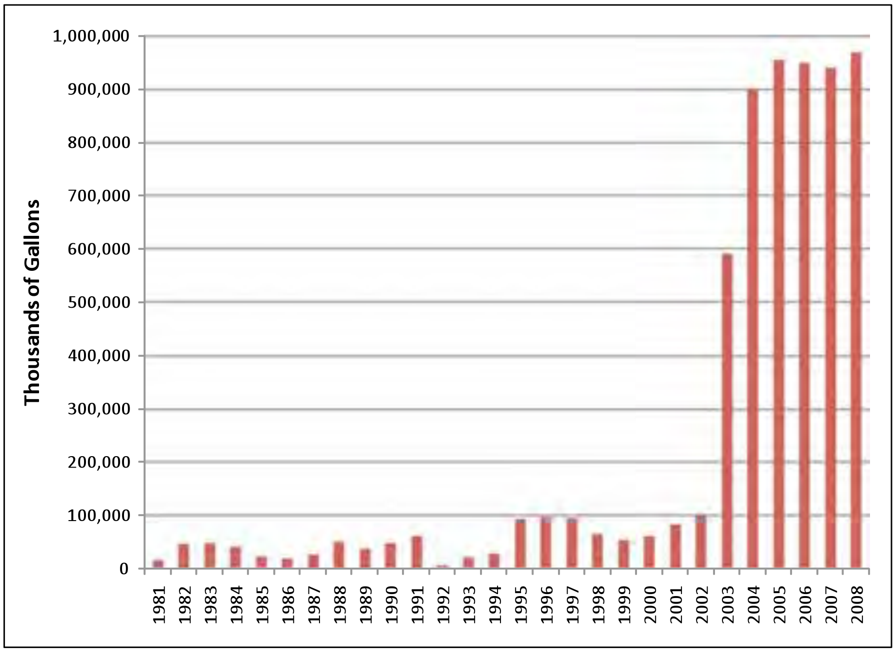


Sources: U.S. Department of Agriculture (USDA) and the Energy Information Administration (EIA).

Beginning in 1980, ethanol's use for blending in gasoline at concentrations of 10 percent by volume (referred to as gasohol or E10) began to gain acceptance in somewhat limited quantities. However, further action by Congress mandated increased use of ethanol to help reduce formation of carbon monoxide beginning in November 1992 via the Wintertime Oxygenate program administered by the U.S. EPA.[xxii] Beginning in January 1995, federal reformulated gasoline regulations took effect that required year-round use of oxygenates (chemicals containing oxygen that are added to fuels, especially gasoline, to make them burn more efficiently) in roughly one-third of the nation's gasoline.[xxiii] ARB adopted reformulated gasoline regulations specific to California that required all gasoline sales to meet the new standard beginning March 1, 1996.[xxiv] Oxygenates for these federal and state programs included ethers (such as MTBE and TAME) and ethanol. The majority of the industry elected to use MTBE, but ethanol was used to blend with a portion of the wintertime oxygenated and reformulated gasoline markets. By the end of the 1990s, ethanol demand in the United States had increased to 1.4 billion gallons per year.

The phase-out of MTBE (due to ground water contamination concerns) and passage of the RFS are the most recent events that resulted in a further expansion of ethanol use as a transportation fuel. The transition to ethanol and away from MTBE began in California following Governor Gray Davis' decision of eliminate its use due to concerns of potential widespread contamination of drinking water sources.[xxv] The practice of reducing use of MTBE spread to other areas of the country, and by January 2005, the transition away from MTBE was completed leaving ethanol as the only oxygenate left standing.[xxvi] Figure 3.2 depicts the estimated fuel ethanol consumption in California between 1981 and 2008. Demand for ethanol rapidly increased in 2003 as a number of refiners elected to transition away from MTBE earlier than the revised deadline of December 31, 2003. Once the MTBE phase-out was completed in 2004, ethanol demand jumped again before stabilizing just short of one billion gallons per year.

Figure 3.2: California Ethanol Demand 1981-2008



Sources: U.S. Federal Highway Administration (FHA), California State Board of Equalization (BOE) and Energy Commission analysis.

Congress took additional steps to expand ethanol's use by initially mandating minimum levels of blending through the RFS provisions of the Energy Policy Act of 2005, followed by an increase of these mandated levels through specific provisions of the Energy Independence and Security Act of 2007 (EISA). The following section describes the recent proposed RFS modifications and their implications for mandated minimum renewable fuel volumes for the United States and California.

Renewable Fuels Standard – Increased Demand for Ethanol and Biodiesel

As required by EISA, the RFS program will be altered to require the sale of 30 billion gallons of renewable fuels by 2020 and 36 billion gallons by 2022.[xxvii] These requirements will require a substantial change to the transportation fuel market place, and the ways to meet these mandates are still being considered by U.S. EPA as it continues accepting comments on its Notice of Proposed Rulemaking (NOPR) until September 25, 2009.[xxviii] The primary change affecting renewable fuel use is the mandated use of ever-increasing quantities of biofuels, predominantly ethanol. Further, the RFS2 will require all obligated parties (refiners, importers, and blenders) to achieve minimum renewable fuel use each year either through actual use (blending) or purchase of RIN credits from other market participants who blended a greater quantity of renewable fuel than was required by the RFS2 requirements. Refiners and importers are required to determine their Renewable Volume Obligation (RVO) each calendar year that is calculated from the RFS percentage assigned by the U.S. EPA during November of the preceding year.[xxix] For 2009, the RFS obligation is 10.21 percent and assumes that 11.1 billion gallons of renewable fuel will be blended into gasoline and diesel fuel. Beginning in 2010, these obligations will include "fair share" blending of four different categories of renewable fuels through actual use or purchase of appropriate RINs.[xxx] The annual nationwide requirements are listed in Table 3.1.

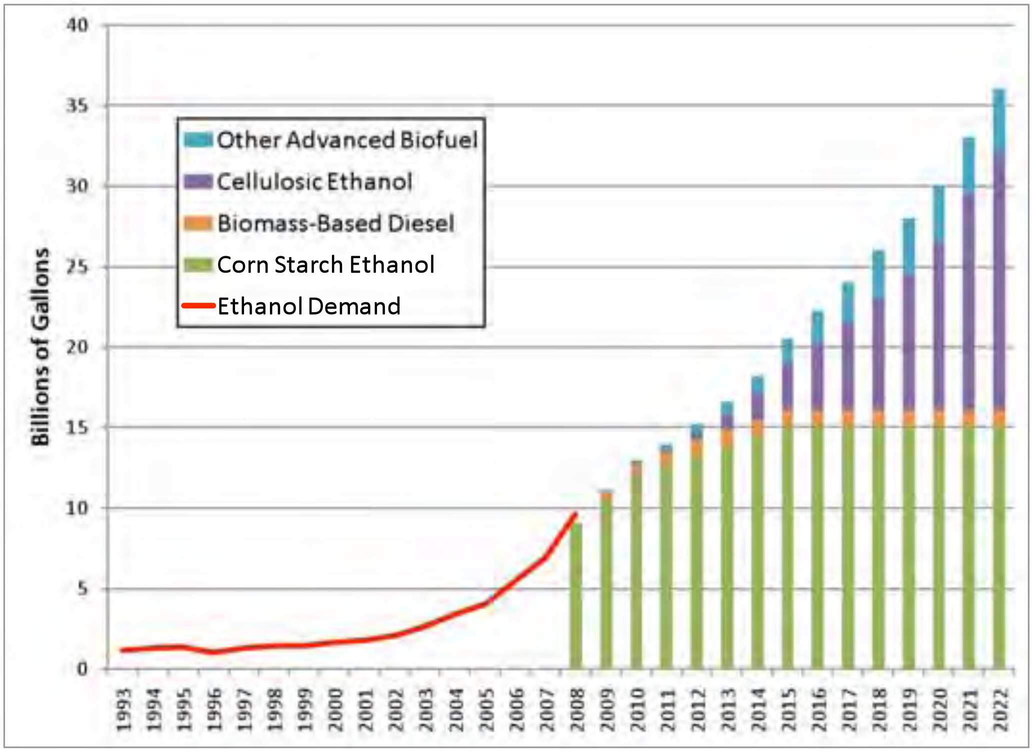
Table 3.1: U.S. RFS2 Requirements 2008-2022

Year	Total Renewable Fuel Requirement Billion Gallons	Starch Derived Biofuel Billion Gallons	Advanced Biofuels			
			Cellulosic Biofuels Billion Gallons	Other Advanced Biofuels Billion Gallons	Biomass Based Diesel Billion Gallons	Total Advanced Biofuels Billion Gallons
2008	9.00	9.00				0.00
2009	11.10	10.50		0.10	0.50	0.60
2010	12.95	12.00	0.10	0.20	0.65	0.95
2011	13.95	12.60	0.25	0.30	0.80	1.35
2012	15.20	13.20	0.50	0.50	1.00	2.00
2013	16.55	13.80	1.00	0.75	1.00	2.75
2014	18.15	14.40	1.75	1.00	1.00	3.75
2015	20.50	15.00	3.00	1.50	1.00	5.50
2016	22.25	15.00	4.25	2.00	1.00	7.25
2017	24.00	15.00	5.50	2.50	1.00	9.00
2018	26.00	15.00	7.00	3.00	1.00	11.00
2019	28.00	15.00	8.50	3.50	1.00	13.00
2020	30.00	15.00	10.50	3.50	1.00	15.00
2021	33.00	15.00	13.50	3.50	1.00	18.00
2022	36.00	15.00	16.00	4.00	1.00	21.00

Source: U.S. Environmental Protection Agency.

The demand for ethanol in 2008 was 9.6 billion gallons or 600 million gallons greater than the RFS requirement for last year. Figure 3.3 shows the progression of ethanol use in the United States and the RFS2 obligations through 2022. Although the estimated demand for 2009 (based on only four months of data) appears too low to achieve compliance with the minimum renewable fuel use requirements, keep in mind that excess RIN credits will likely be used by some obligated parties and that ethanol blending is expected to continue increasing throughout the remainder of 2009.

Figure 3.3: U.S. Ethanol Use and RFS Obligations 1993-2022



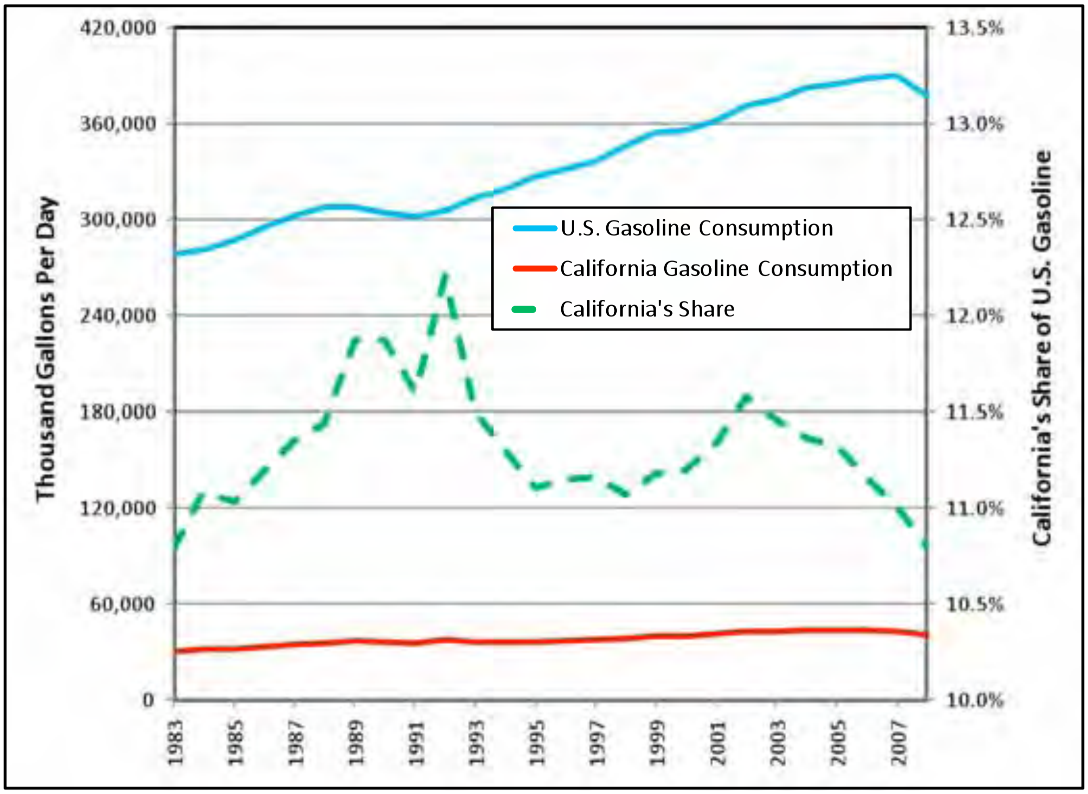
Sources: Energy Information Administration (EIA), U.S. EPA , and Energy Commission analysis.

California Fair Share From RFS2

To determine what quantity of renewable fuel might be needed in California to comply with the RFS2, staff had to determine what the "fair share" RFS2 obligation might be under both Low and High Demand Cases for gasoline over the forecast period. Although compliance with the RFS2 by refiners, importers, and blenders can include acquisition of RIN credits and overcompliance on a company basis in other areas of the United States outside California, for this part of the analysis, staff assumed that all obligated parties in California would be complying by blending their "fair share" of renewable fuels within the state's borders. This approach will yield more of a "worst case" infrastructure assessment but still recognizes that the forecasted demand for ethanol and biodiesel could be a bit less than presented in this report.

The first step was to figure out what the "fair share" should be for the various types of renewable fuels mandated under the proposed RFS2 standards. Staff analyzed California's gasoline demand relative to the total in the United States. Since 1983, U.S. motor gasoline use has been growing at an average annual growth rate of 0.95 percent, rising from an average consumption of 278 million gallons a day in 1983 to 377 million gallons a day in 2008.[xxxi] California's share of U.S. gasoline consumption has fluctuated over the last 25 years and is the same percentage in 2008 as it was back in 1983. (See Figure 3.4.) Between 1998 and 2008, California's share of total gasoline demand has averaged 11.2 percent. However, this percentage has been steadily declining between 2002 (11.6 percent) to 2008 (10.8 percent).

Figure 3.4: U.S. and California Motor Gasoline Consumption 1983-2008



Sources: Energy Information Administration (EIA), California BOE, and Energy Commission analysis.

To meet the regulatory necessities of RFS2 over the forecast period, staff calculated California's share of gasoline demand by comparing the Energy Commission gasoline demand forecast to that of the *2009 Annual Energy Outlook Forecast Energy Information Administration Forecast* that was revised in April 2009.[xxxii] This calculated California share of gasoline demand was then applied to each of the four RFS2 renewable fuel annual minimum requirements (Refer back to Table 3.1.) to determine how much ethanol and biodiesel would be necessary to achieve "fair share" compliance with the RFS2. For 2023 through 2030, the RFS2 annual domestic requirements were held fixed at the 2022 levels. However, it is recognized that the EPA proposed RFS2 regulations note that values post 2022 may be adjusted and could be higher than the values used by staff in this forecast analysis. Under the Low Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,272 million gallons in 2010 to 2,778 million gallons by 2020. Under the Low Demand Case for diesel fuel, minimum biodiesel demand in California is forecast to grow from 41 million gallons in 2010 to 69 million gallons by 2020. (See Table 3.2.)

Table 3.2: California Renewable Fuel Requirements 2008-2030 Low Gasoline and Diesel Fuel Demand Case

Year	Total Ethanol Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels			
			Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	0.974	0.974				0.000
2009	1.159	1.148		0.011	0.000	0.011
2010	1.272	1.241	0.010	0.021	0.041	0.072
2011	1.311	1.256	0.025	0.030	0.049	0.104
2012	1.442	1.340	0.051	0.051	0.061	0.162
2013	1.630	1.446	0.105	0.079	0.062	0.245
2014	1.819	1.527	0.186	0.106	0.063	0.355
2015	2.051	1.577	0.315	0.158	0.065	0.538
2016	2.206	1.557	0.441	0.208	0.065	0.713
2017	2.351	1.533	0.562	0.256	0.066	0.884
2018	2.507	1.504	0.702	0.301	0.067	1.070
2019	2.646	1.470	0.833	0.343	0.068	1.244
2020	2.778	1.437	1.006	0.335	0.069	1.410
2021	2.979	1.396	1.257	0.326	0.070	1.652
2022	3.171	1.359	1.450	0.362	0.071	1.883
2023	3.145	1.348	1.438	0.359	0.071	1.868
2024	3.101	1.329	1.417	0.354	0.071	1.843
2025	3.086	1.323	1.411	0.353	0.072	1.835
2026	3.065	1.314	1.401	0.350	0.072	1.824
2027	3.082	1.321	1.409	0.352	0.072	1.833
2028	3.074	1.318	1.405	0.351	0.072	1.829
2029	3.106	1.331	1.420	0.355	0.073	1.847
2030	3.109	1.332	1.421	0.355	0.072	1.849

Source: Energy Commission analysis

Under the High Demand Case for gasoline, total ethanol demand in California is forecast to rise from 1,299 million gallons in 2010 to 2,639 million gallons by 2020. Under the High Demand Case for diesel fuel, minimum biodiesel demand in California is forecast to grow from 40 million gallons in 2010 to 68 million gallons by 2020 (Table 3.3).

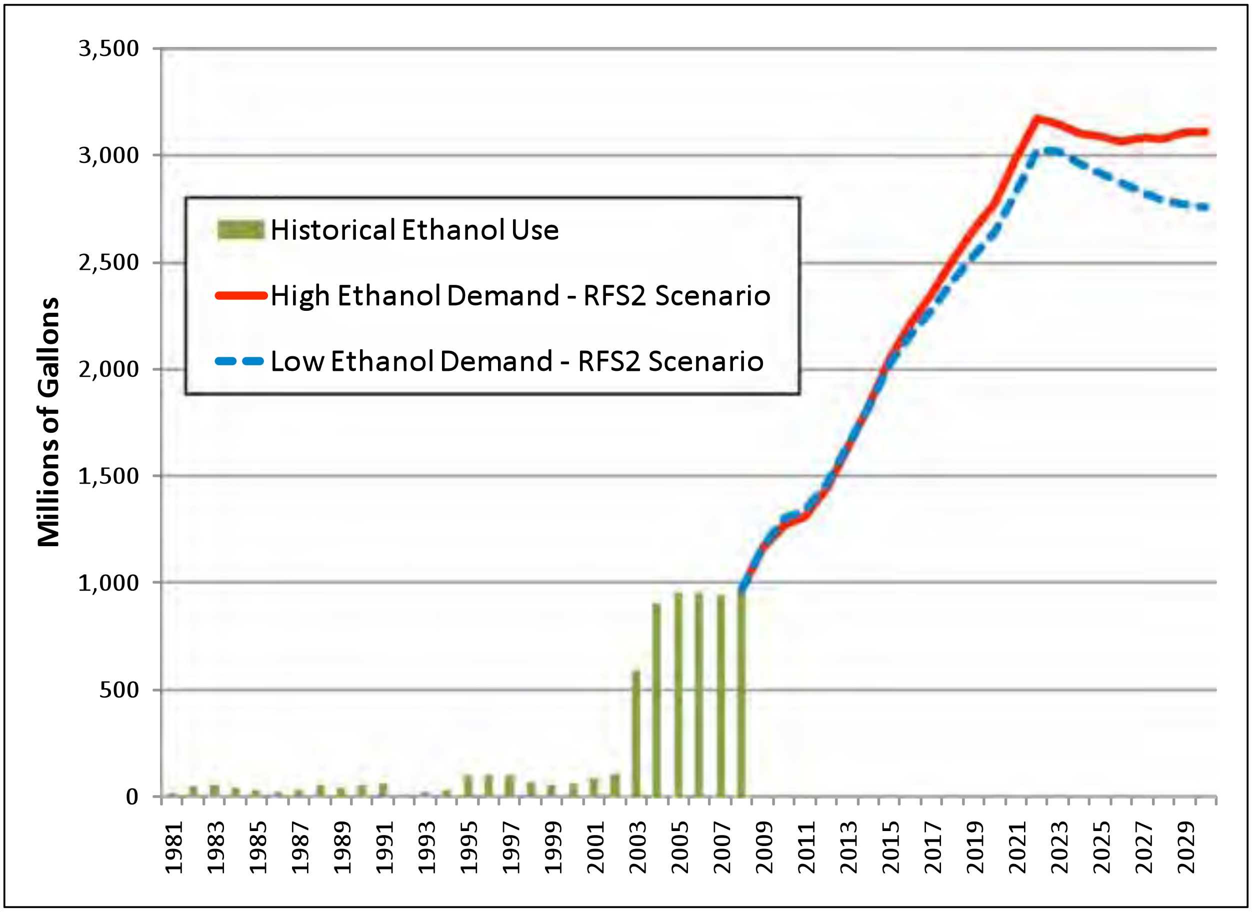
Table 3.3: California Renewable Fuel Requirements 2008-2030 High Gasoline and Diesel Fuel Demand Case

Year	Total Ethanol Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels Cellulosic Biofuels Bil. Gallons	Other Advanced Biofuels Bil. Gallons	Biomass Based Diesel Bil. Gallons	Total Advanced Biofuels Bil. Gallons
2008	0.969	0.969				0.000
2009	1.165	1.154		0.011	0.000	0.011
2010	1.299	1.267	0.011	0.021	0.040	0.072
2011	1.339	1.283	0.025	0.031	0.047	0.103
2012	1.462	1.359	0.051	0.051	0.058	0.161
2013	1.641	1.456	0.106	0.079	0.059	0.244
2014	1.809	1.519	0.185	0.106	0.060	0.350
2015	2.024	1.557	0.311	0.156	0.062	0.529
2016	2.156	1.522	0.431	0.203	0.061	0.696
2017	2.279	1.486	0.545	0.248	0.063	0.856
2018	2.412	1.447	0.675	0.289	0.065	1.029
2019	2.524	1.402	0.795	0.327	0.066	1.188
2020	2.639	1.365	0.956	0.319	0.068	1.342
2021	2.816	1.320	1.188	0.308	0.069	1.565
2022	3.023	1.295	1.382	0.345	0.071	1.798
2023	3.015	1.292	1.378	0.345	0.071	1.794
2024	2.957	1.267	1.352	0.338	0.071	1.761
2025	2.911	1.248	1.331	0.333	0.072	1.735
2026	2.868	1.229	1.311	0.328	0.072	1.711
2027	2.826	1.211	1.292	0.323	0.072	1.687
2028	2.787	1.195	1.274	0.319	0.071	1.664
2029	2.769	1.187	1.266	0.316	0.071	1.653
2030	2.753	1.180	1.258	0.315	0.070	1.643

Source: Energy Commission analysis.

California's "fair share" RFS2 obligations are forecast to significantly increase the quantity of ethanol used in the state over the forecast period. The projected ethanol demand increase is greatest under the Low Gasoline Demand Case, more than doubling to 2.0 billion gallons by 2015 before peaking at 3.2 billion gallons by 2022. Figure 3.5 depicts ethanol demand growth in California between 1981 and 2030.

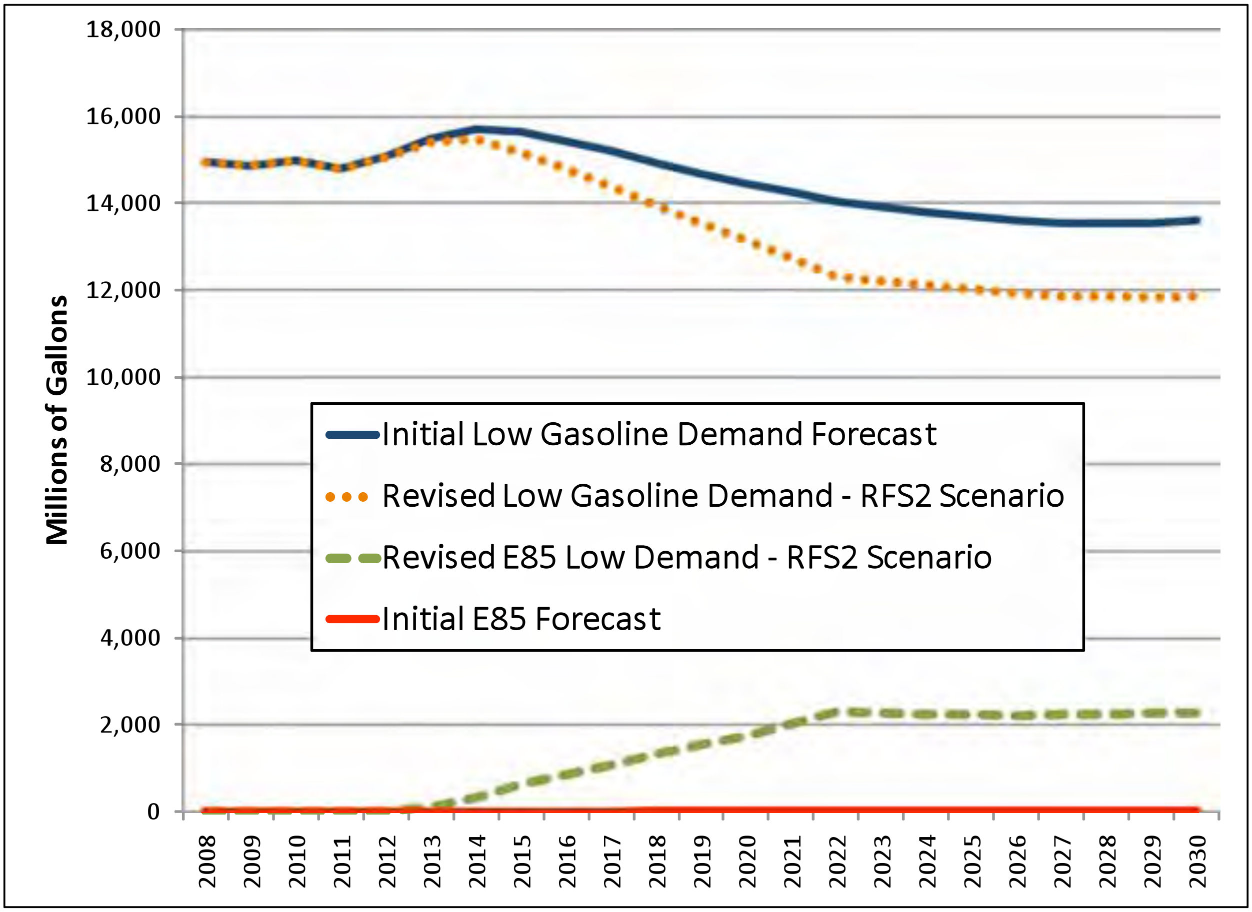
Figure 3.5: California Historical and Forecast Ethanol Demand



Source: Energy Commission analysis.

The federal mandated use of ever-increasing quantities of ethanol over the forecast period will dampen the outlook for gasoline demand further than improved fuel economy standards. Figure 3.6 illustrates how the Energy Commission's Low Gasoline Demand Case projections are decreased 12.6 percent by 2030 as a consequence of higher ethanol use mainly in the form of greatly increased sales of E85 that will be necessitated by the RFS2 requirements.

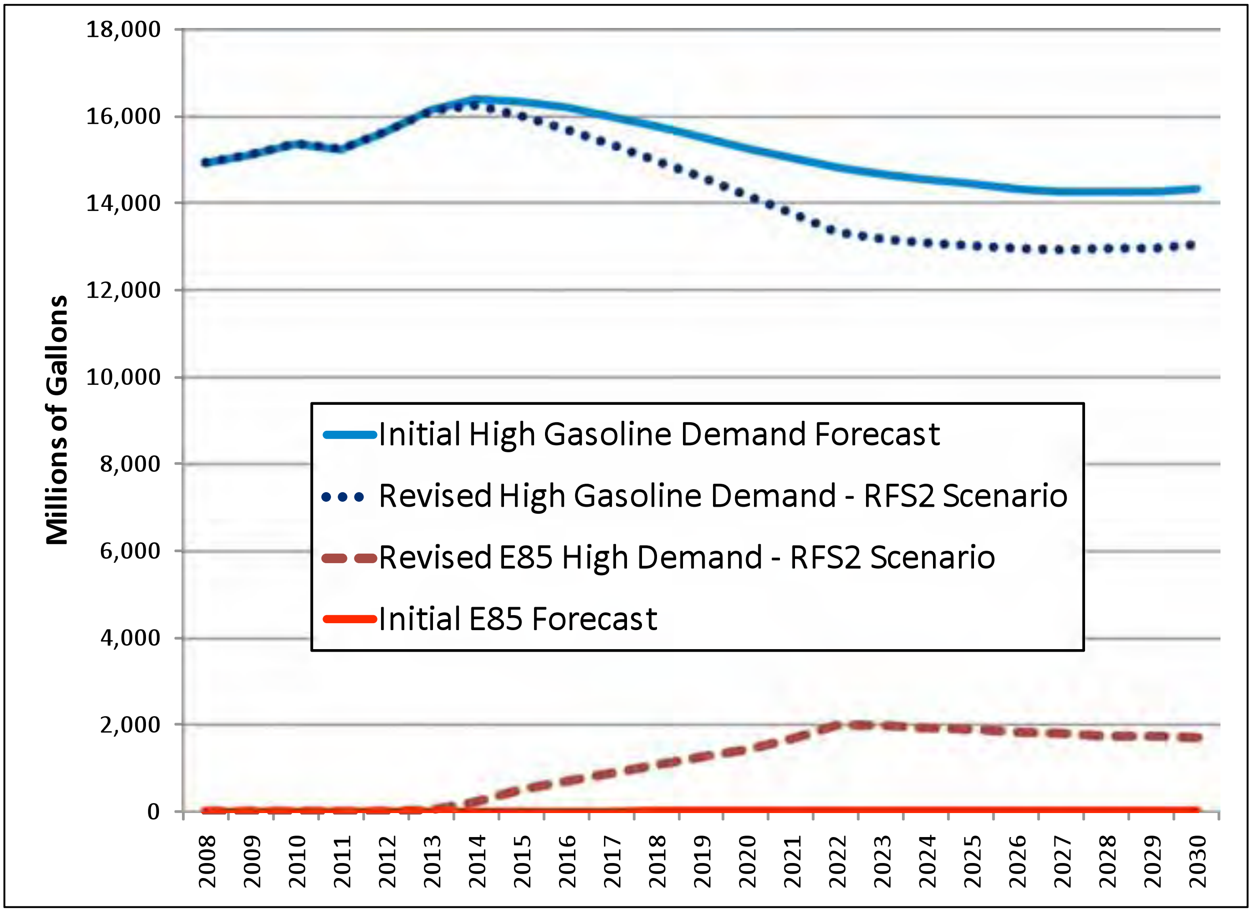
Figure 3.6: RFS Impact on California Initial Low Gasoline Demand Forecast



Source: Energy Commission analysis.

The impact on the High Gasoline Demand Case is slightly less, decreasing the initial outlook 9.0 percent by 2030 as illustrated by Figure 3.7.

Figure 3.7: RFS Impact on California Initial High Gasoline Demand Forecast



Source: Energy Commission analysis.

Greater use of ethanol in California could be accomplished by (1) adoption of new upper limits for low-level ethanol blends in excess of the current E10 standard, or (2) increased sales of E85 (a mixture of 15 percent gasoline and 85 percent ethanol). Experts generally recognize that there are potential vehicle operability and emission issues that need to be addressed before the low-level cap on ethanol blends in gasoline (referred to as the *blend wall*) can be increased to levels greater than 10 percent.[xxxiii]

Ethanol Blend Wall

It is estimated that ethanol demand in California will eclipse an average of 10 percent by volume in all gasoline sales between 2012 and 2013, depending on gasoline demand growth rates. Original engine manufacturers (OEMs) generally have vehicle warranties that are voided if the owner uses gasoline with more than 10 percent by volume ethanol. OEMs are concerned about potential harm to the catalyst in their vehicles. A recent study conducted on behalf of the University of Minnesota, however, suggests existing vehicles could operate at slightly higher ethanol concentrations without undue operational or emissions problems.[xxxiv] The U.S. DOE is conducting vehicle testing of intermediate ethanol blends (E15 and E20) to measure effects on vehicle emissions, catalysts, and engine durability. This group has recently released a preliminary report that did not identify any significantly detrimental issues.[xxxv] Lastly, U.S. EPA has been petitioned by Growth Energy to allow the ethanol blend wall to be increased to 15 percent by volume or E15.[xxxvi]

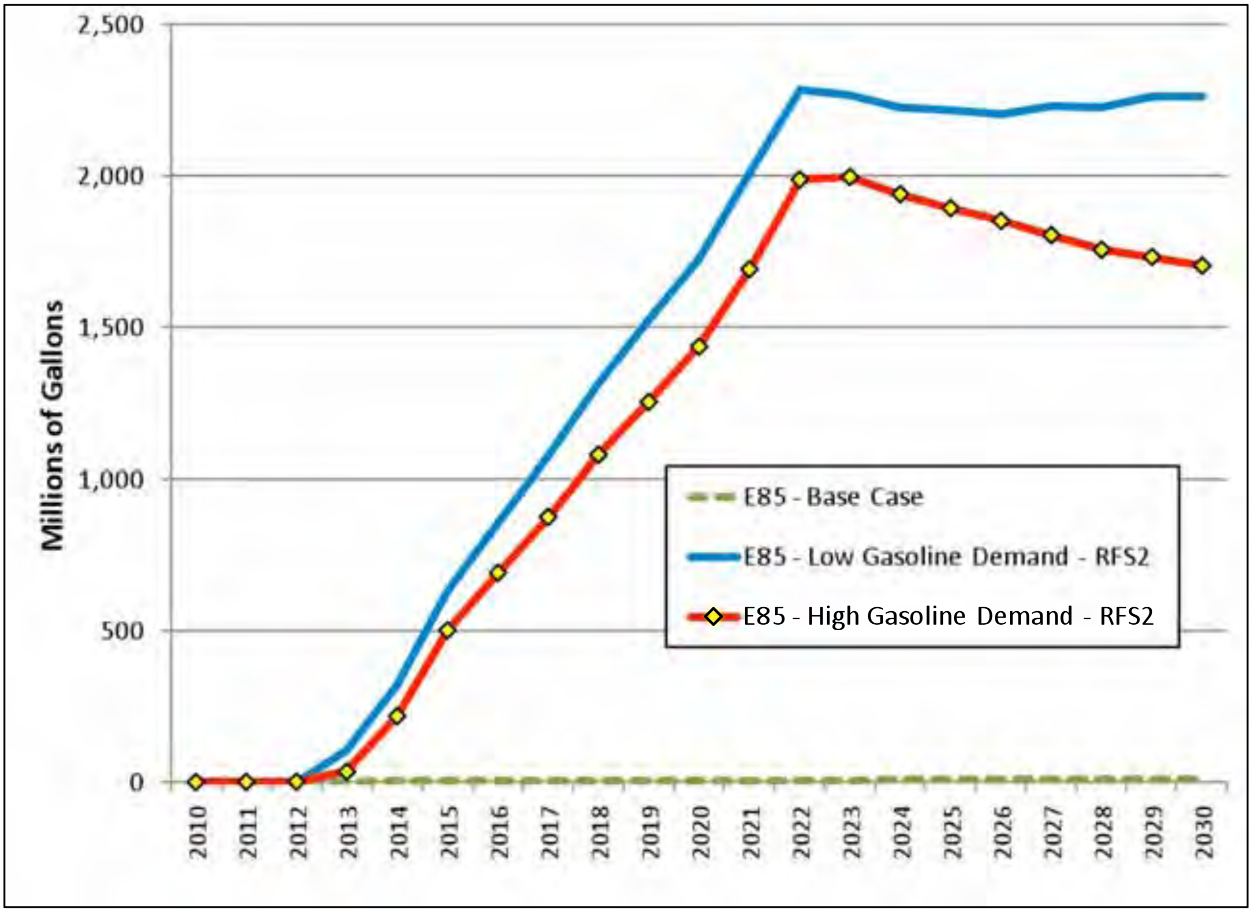
It is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume, even if the EPA ultimately grants permission for U.S. refiners and marketers to go to E15. California's revised reformulated gasoline specifications (referred to as the revised Predictive Model) go into effect on January 1, 2010. Information used to develop mathematical relationships between various gasoline properties (such as sulfur and oxygen content) and vehicle emissions (both evaporative and tailpipe) did not include gasoline with blends of ethanol greater than 10 percent by volume. As such, this ARB regulation would have to be modified before E15 blends could be considered for use in the state. Since this process would require several years to complete (if this path were to be pursued) and the outcome is uncertain, staff has assumed in this analysis that E10 will remain the practical upper limit in California gasoline low-level blends over the foreseeable future.

Increased Ethanol Use in Gasoline – E85

Since the ethanol blend wall in California is assumed to remain at 10 percent by volume over the forecast period, the only reasonable means of using more ethanol in transportation fuels is to increase the sales of E85. As of October 2008, there were nearly 382,000 registered vehicles in California that could use either gasoline or E85.[xxxvii] These vehicles are referred to as FFVs. Although there is a large population of FFVs in California, there are only a few retail stations that offer E85. As of July 2009, there were only 25 retail stations that offered E85 to the public. Staff expects that the quantity of E85 sold in California will increase in response to higher levels of mandated ethanol use due to the RFS2. However, the pace of this expansion may be inadequate to achieve compliance due to a variety of infrastructure challenges and disincentives.

There are several challenges to expansion of E85 sales in California. Availability of E85 will need to increase dramatically to ensure that sufficient volumes of E85 can be sold to keep pace with RFS2 requirements. Assuming a 10 percent ethanol blend wall, E85 sales in California are forecast to rise from 1.1 million gallons in 2010 to 1,725 million gallons in 2020 and 2,262 million gallons by 2030 under the Low Demand Case for gasoline. Figure 3.8 shows the annual E85 forecast for both the Low and High Demand Cases.

Figure 3.8: California E85 Demand Forecast 2010-2030



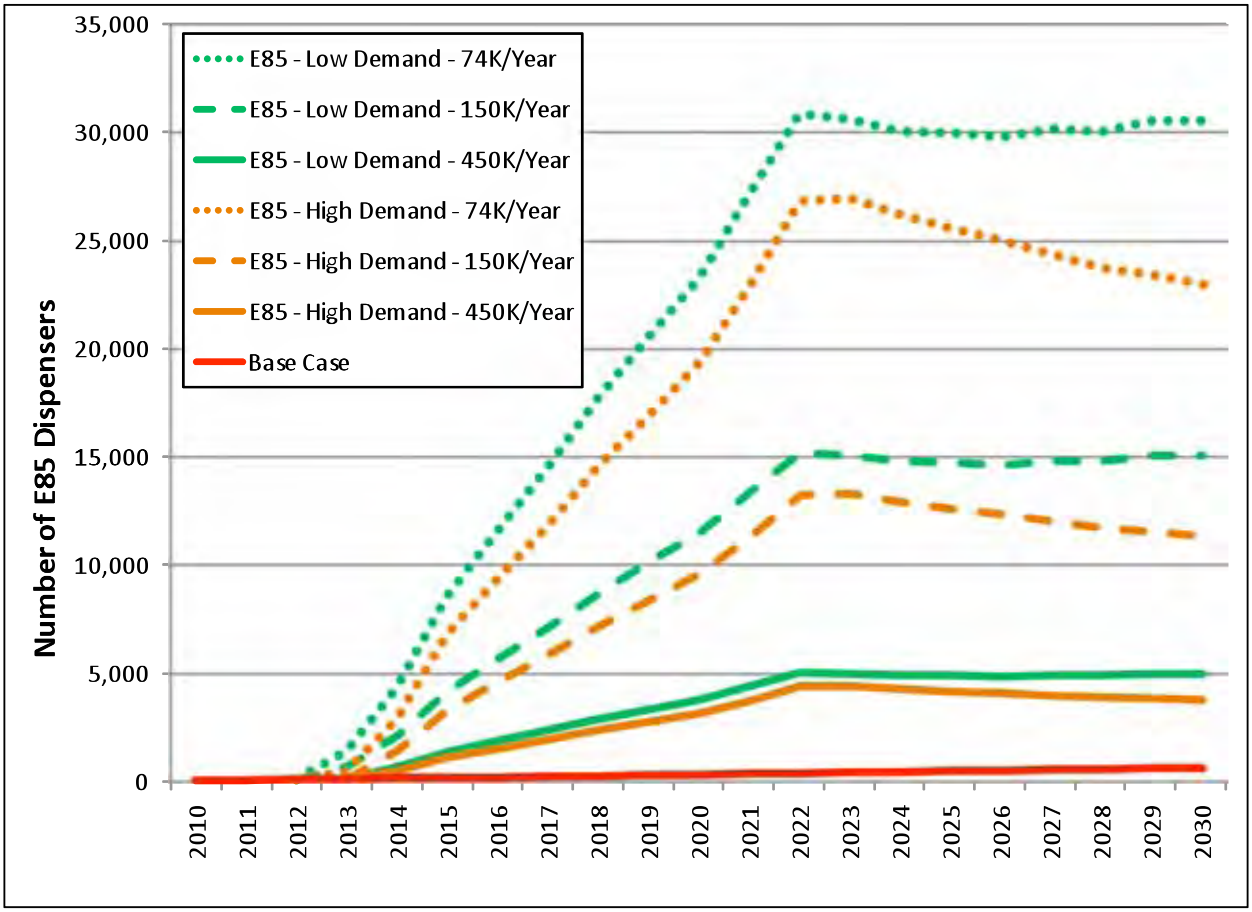
Source: Energy Commission analysis.

However, the proposed RFS2 regulations do not require that retail station owners and operators make available E85 for sale to the public. Refiners, importers, and blenders have an obligation to comply with the RFS2 standards, but retail station operators do not have any obligation. This is an apparent "disconnect" in the RFS2 policy that could easily result in a retail infrastructure that is inadequate to handle the necessary increase in E85 sales.

Another potential issue is what type of base gasoline will be necessary to blend with ethanol to produce E85. If the blendstock is something other than CARBOB for E10 blending, additional segregated storage tanks would be required throughout the production and distribution infrastructure to accommodate this new gasoline blendstock.

To calculate the number of retail stations that would need to offer E85, staff had to first estimate the number of E85 dispensers that would need to be operating. This quantity of E85 dispensers can vary depending on the annual statewide demand for E85 and the average annual distribution of E85 per dispenser. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 4,400 and 30,900 E85 dispensers by 2022. To put that estimated number of new dispensers into perspective, there were a total of approximately 42,050 retail dispensers in California during summer of 2008 for all fuel types.[xxxviii] The average annual distribution of transportation fuel per fuel dispenser in California between July 1, 2007, and June 30, 2008, is estimated at 452,000 gallons. However, staff estimates that a dispenser that sells only one type of fuel sold an average of between 150,000 and 175,000 gallons over this same period.[xxxix] Actual per-station E85 annual sales figures for Minnesota are much lower, averaging about 74,000 gallons.[xl] The impact of lower annual throughput and minimum per-gallon margins necessary to make a profit are discussed later in this section. Figure 3.9 depicts the growth in E85 dispenser availability over the forecast period that would be necessary to distribute sufficient volumes of E85 to help comply with the RFS2.

Figure 3.9: California E85 Dispenser Forecast 2010-2030



Source: Energy Commission analysis.

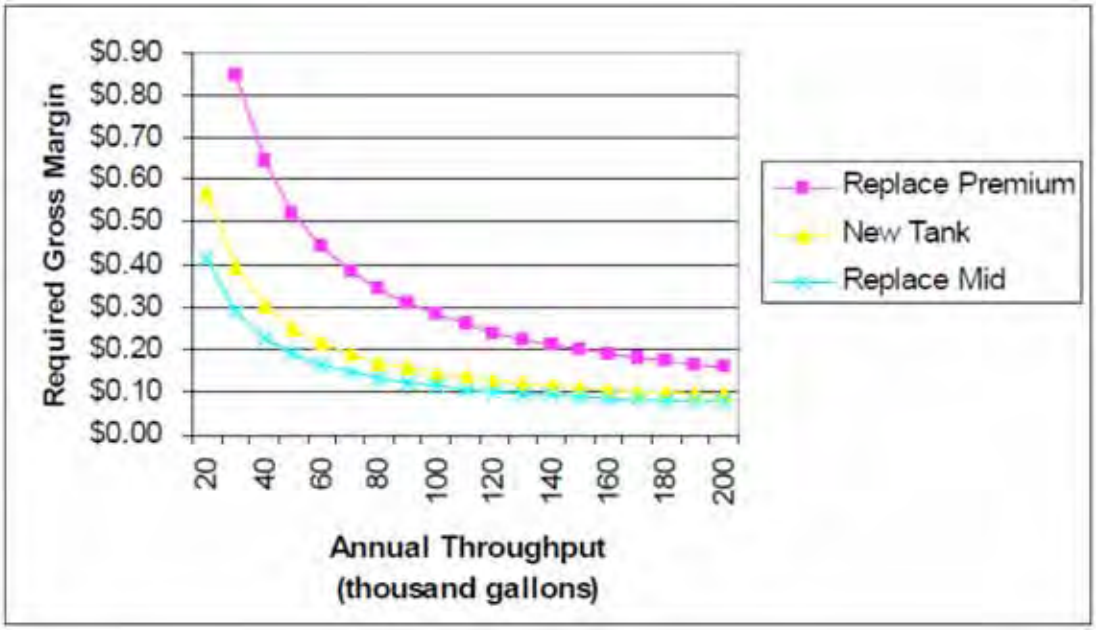
The significant increase in E85 dispenser availability at California retail stations has a potential barrier or increased difficulty associated with equipment approval. Most (if not all) retail dispensers have been certified by Underwriters Laboratories (UL) or are assembled using UL-approved parts and components. During October 2006, UL "suspended authorization for manufacturers to use UL markings (Listing or Recognition) on components for fuel-dispensing devices that specifically reference compatibility with alcohol-blended fuels that contain greater than 15 percent alcohol i.e., ethanol, methanol or other alcohols."[xli] UL announced during October 2007 that it had developed procedures for reviewing dispensers suitable for selling E85.[xlii] This step means that manufacturers may submit components intended for use in E85 dispensers for UL certification. It is not known how many dispensers designed for dispensing E85 have been certified by UL, if any.[xliii] Furthermore, it is uncertain how this situation may or may not be impeding installation of E85 dispensers in California since several new retail locations have starting selling E85 over the last several months. It is possible that variances or waivers are being granted for E85 equipment submitted for approval by local jurisdictions that have oversight.

E85 retail infrastructure is expensive. Costs for installing a new UST, dispenser, and appurtenances range between $50,000 and $200,000.[xliv] Statewide, the E85 retail infrastructure investment costs could be as low as $192 million to upwards of $4.7 billion between 2009 and 2020. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion. One approach to reduce this anticipated infrastructure cost is for the California Legislature to consider requiring new building code standards that all gasoline related equipment (underground storage tanks, dispensers, associated piping, and so on) be E85-compatible for construction of any new retail stations or replacement of any gasoline related equipment beginning January 1, 2011. This approach would increase the likelihood of success of renewable fuel penetration policy goals.

Costs can also be reduced if an existing UST is used to store and dispense the E85. Dedicated mid-grade and premium storage tanks are two examples, although each option has additional complications. The mid-grade replacement option is estimated to cost only $20,000 but requires a station that has a dedicated mid-grade gasoline tank.[xlv] The portion of retail stations in California that still have dedicated mid-grade USTs is estimated at no more than 30 percent.[xlvi] This option in California is limited and will decline in the future since new retail stations do not normally install a dedicated mid-grade UST. The National Renewable Energy Laboratory (NREL) also examined a scenario whereby a retail station owner uses a dedicated premium grade gasoline UST to store and dispense E85. This option will likely eliminate premium and mid-grade gasoline sales at a retail station. It should also be noted that premium grade gasoline sales usually command the highest profit margin. A retail station owner would have to believe that the E85 margins would be even higher when compared to premium gasoline for this business strategy to be a viable option.

NREL conducted modeling to assess various factors that can impact profitability of a decision to modify an existing retail station to dispense E85. Figure 3.10 shows the three options (new tank, use of existing mid-grade tank, and use of existing premium tank) and the per-gallon level of margin required to sustain profitability over a wide range of annual E85 fuel throughput. The graph illustrates that the new tank and mid-grade tank options are similar, while the premium option requires higher margins at any level of throughput.

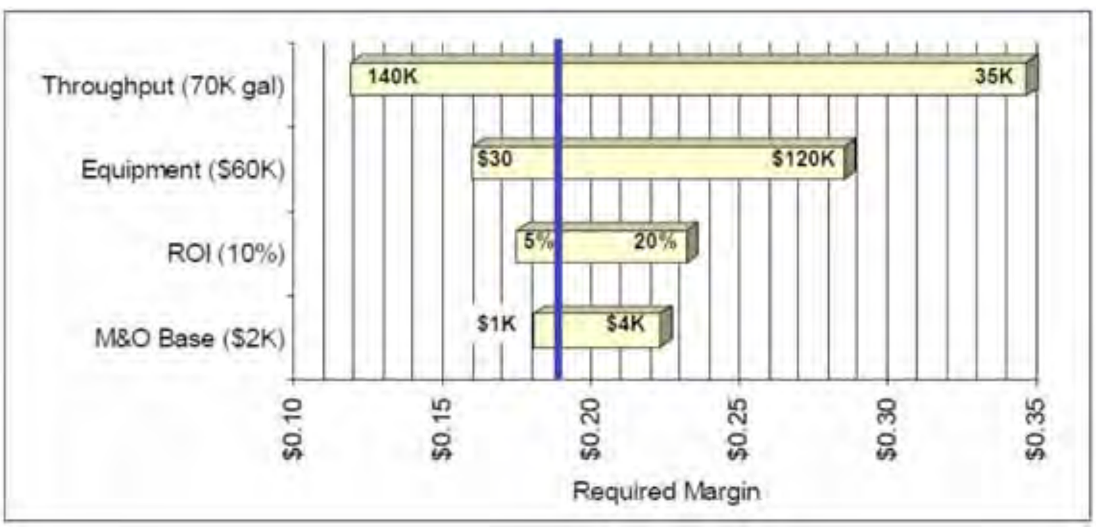
Figure 3.10: E85 Business Scenario Margins and Annual Throughput



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 5, page 13.

The actual level of E85 sales is probably the most important variable for determining the per-gallon margin necessary to be profitable. Variation in the actual cost of equipment is the second most important variable. Figure 3.11 shows how the level of margin required to be profitable changes as the various factors are adjusted upward or downward.

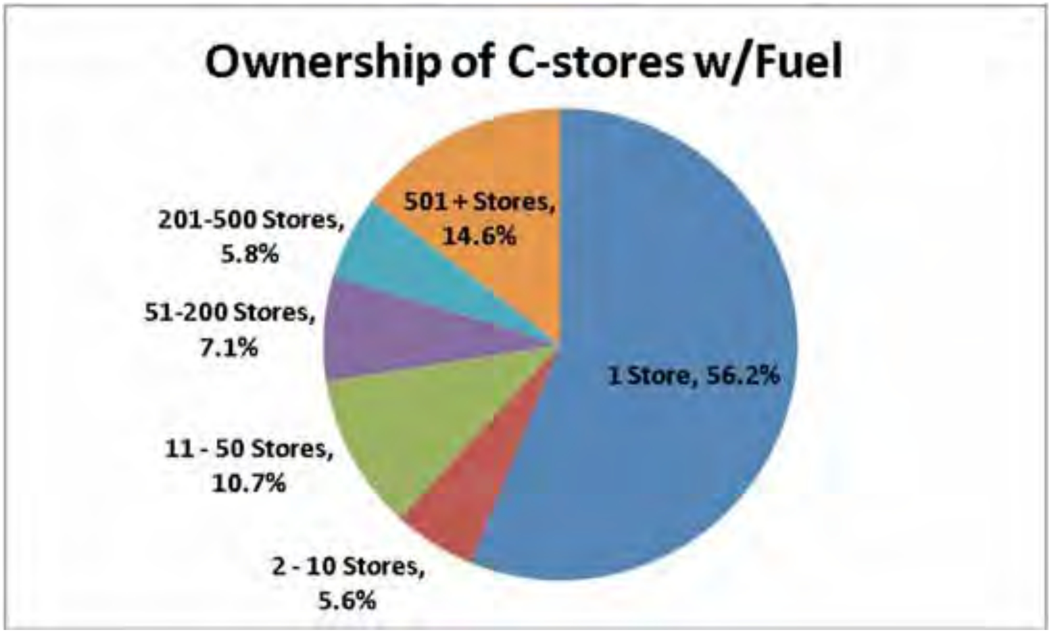
Figure 3.11: E85 New Tank Scenario Factors and Required Margin



Sources: NREL Technical Report TP-540-41590, Dec. 2007, Figure 6, page 15.

Most retail station owners and operators could have a difficult time obtaining sufficient resources to finance this type of work. Nearly 60 percent of retail stations in the United States are owned and operated by someone who has one store. (See Figure 3.12.)[xlvii] Large oil companies are actually reducing the number of retail stations they own and operate.

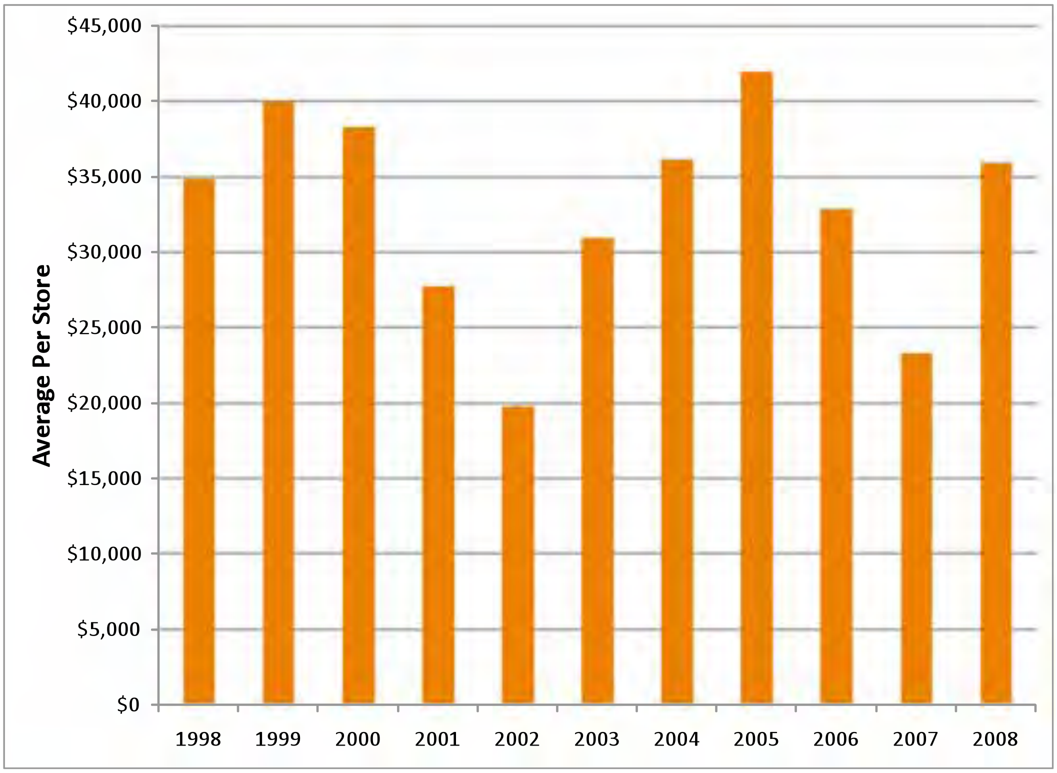
Figure 3.12: U.S. Convenience Store Ownership Profile



Sources: National Association of Convenience Stores (NACS) and TDLinx Official Industry Store Count, Feb. 2009.

Once again, there is no obligation to install E85 dispensers nor is there a strong financial incentive for a typical retail station owner. During 2008, more than 80 percent of the gasoline sold to the public nationwide was through convenience stores.[xlviii] These places of business have continued to be profitable over the last decade, averaging nearly $32,700 per store pre-tax profits between 1999 and 2008.[xlix] Figure 3.13 shows that these pre-tax profits are not steady but can fluctuate over time. It is possible that because most stations are operated by a sole proprietor and pre-tax profits are historically less than $40,000 per year, voluntary installation of a new E85 retail dispenser, UST, and associated piping is a business proposition that would be difficult to justify. In fact, the majority of retail locations that have recently installed E85 dispensers in California have done so with either partial or complete financial assistance from other funding sources.[l] Over the near term, the greatest barrier to expanded use of ethanol is an adequate and timely build-out of the necessary minimum E85 retail fueling infrastructure capability. The costs of such an effort could range somewhere between $50,000 and $200,000 per retail station location. It is estimated that, at a minimum, an average of 545 E85 dispensers *per year* would need to be installed in California between 2014 and 2022, costing between $27 million and $218 million per year.

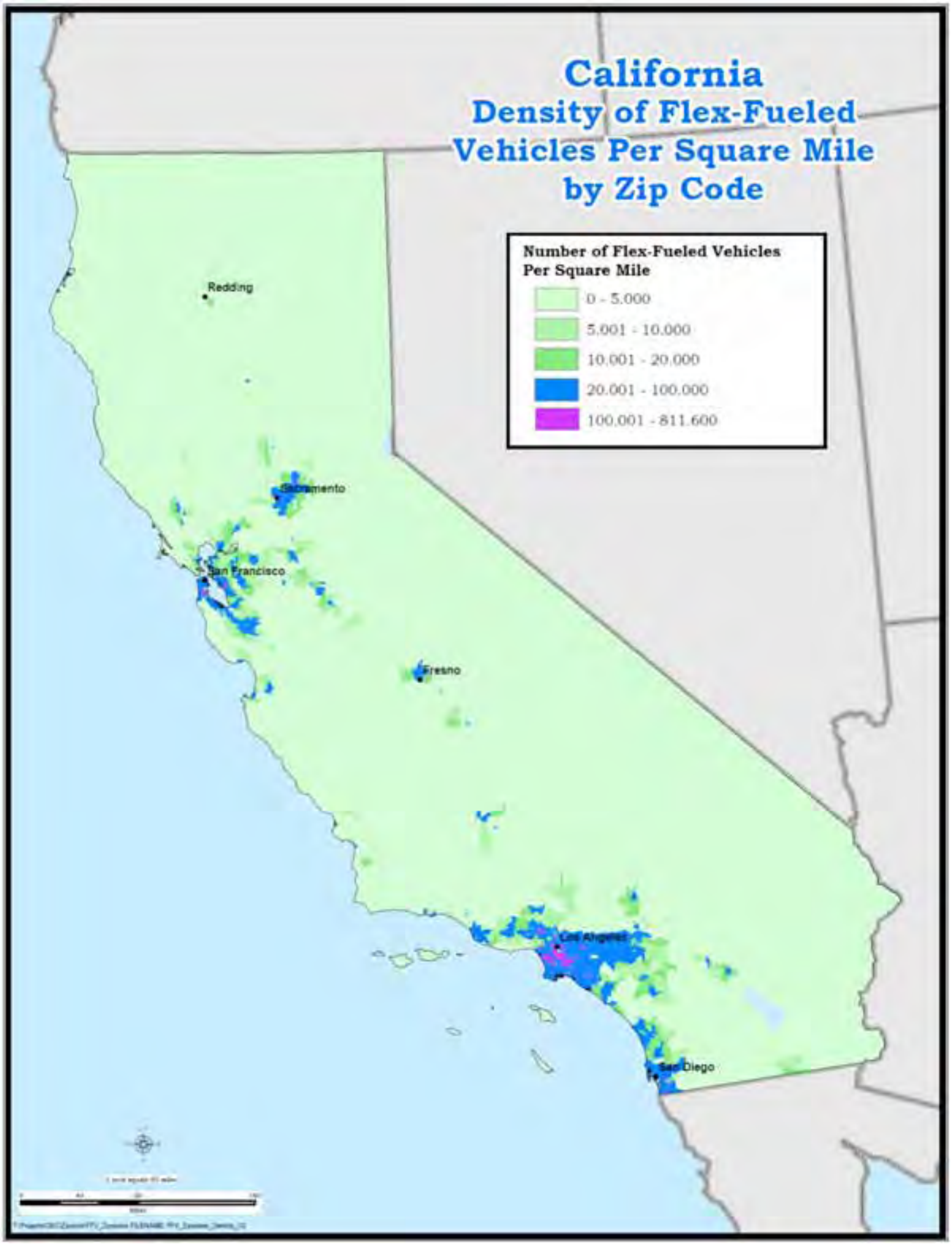
Figure 3.13: U.S. Convenience Store Average Pre-Tax Profits 1998-2008



Sources: NACS State of the Industry Report data and 2009 press release.

However, the state should continue to provide as much assistance as available resources permit to help increase the likelihood of successful E85 availability. One such example could be the periodic publication of FFV ownership density maps that show which locations (by ZIP code divisions) have the highest concentration of FFVs so that retail station owners and other business interests can initially target locations that have a greater number of FFVs. Figure 3.14 depicts the FFV density for California for April 2008. The darker areas have the greatest density of FFVs per geographic area, while the lightest shading has the lowest concentration.

Figure 3.14: California FFV Density Map – April 2008

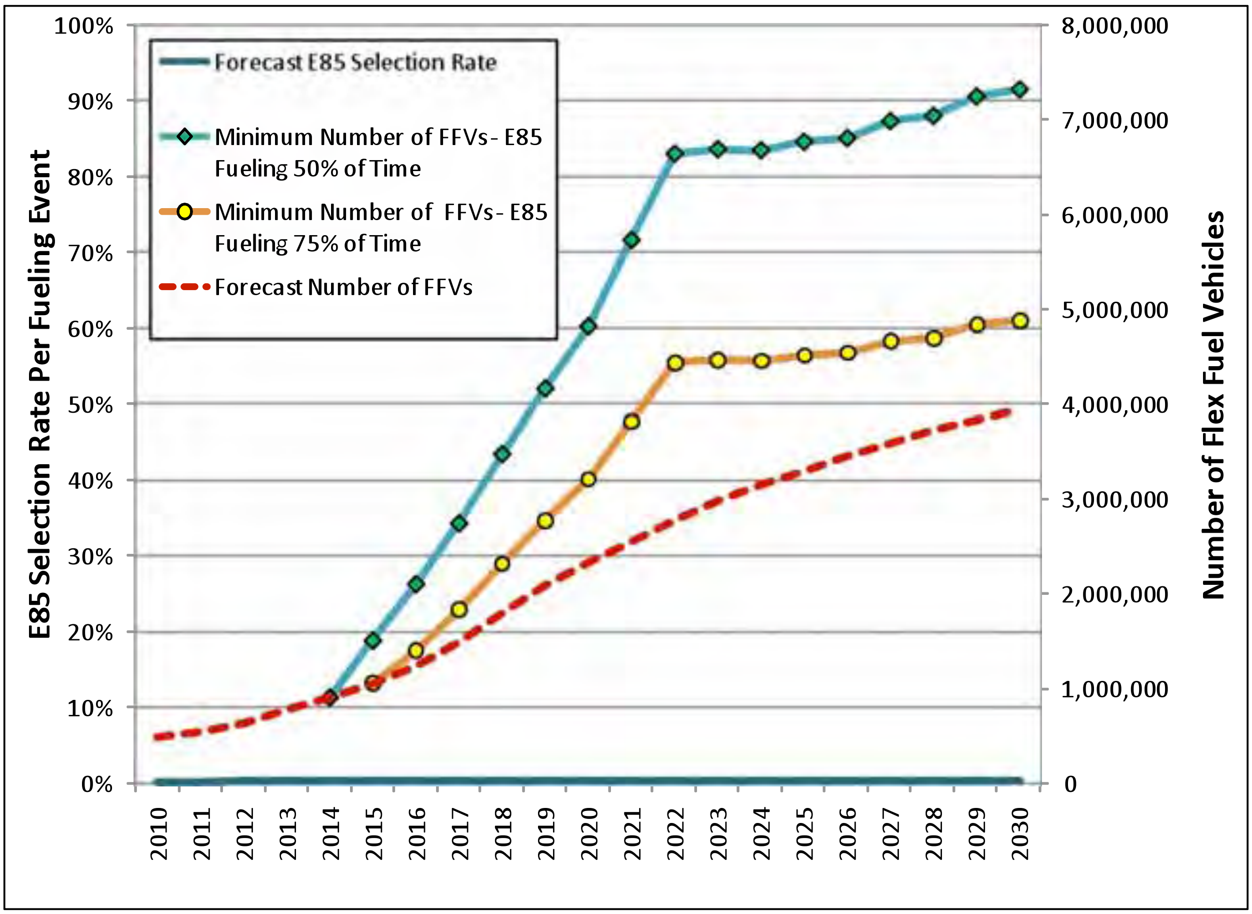


Sources: California Department of Motor Vehicle (DMV) data and Energy Commission analysis.

E85 Demand and Flexible Fuel Vehicle Forecast

Along with the forecasted rise of E85 sales in California, there is a commensurate rise in the number of FFVs that would be necessary to use greater volumes of E85. The FFV forecast depends on the total demand for E85, the fuel economy of FFVs, the average number of vehicle miles traveled (VMT) per FFV, and the frequency of E85 fueling by a typical FFV owner. Based on these interrelated factors, the FFV population would need to grow from a total of 382,000 vehicles in October 2008 to as many as 4.8 million FFVs by 2020 and 7.3 million by 2030. Figure 3.15 shows the FFV forecast for Low Demand Gasoline Cases that yielded the higher E85 demand levels. The lower FFV forecasts assume that FFV owners elect to use E85 for the majority of each fueling event (75 percent of the time). The higher numbers of FFVs would be required if owners fueled with E85 at least 50 percent of the time.

Figure 3.15: California FFV Demand Forecast 2010-2030



Source: Energy Commission analysis

Based on these FFV forecast trends, a significantly greater number of FFVs will need to be sold in California than are assumed in the base case as soon as 2015. Most automakers are believed to have committed to producing up to half of their new vehicle models as FFV-compliant by 2012, contingent upon an adequate fueling infrastructure.[li] However, the ability of automobile manufacturers to produce an even greater portion of their new models as FFVs for sale in California could be challenged due to increasingly stringent emission standards and higher fuel economy standards.

Flexible Fuel Vehicles – Technical and Policy Challenges

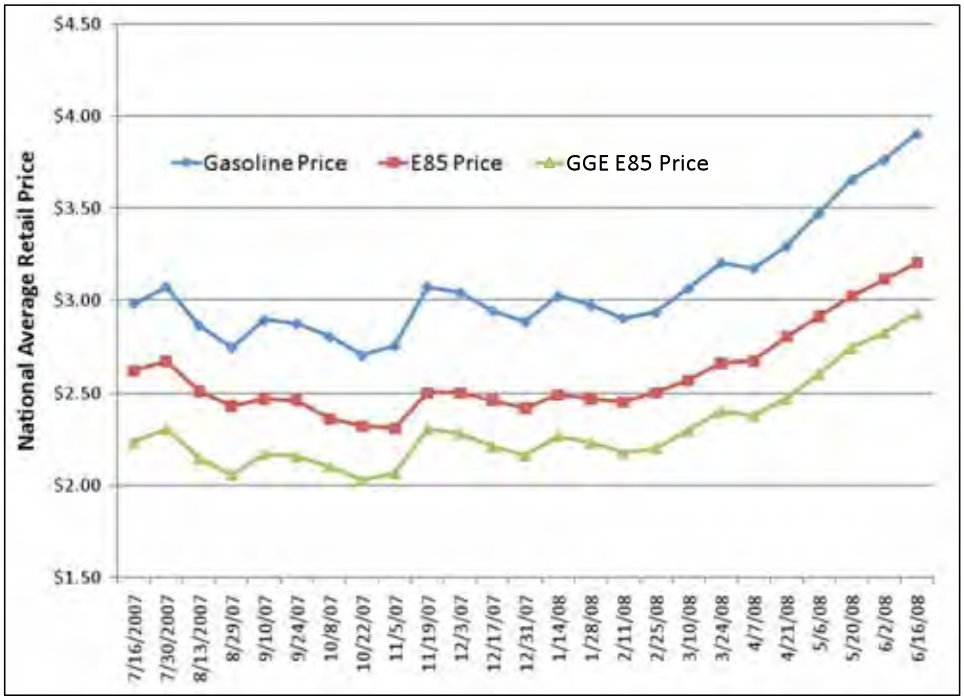
New vehicles offered for sale in California have to include an increasing percentage of models that meet super–ultra-low-emission vehicle (SULEV) and PZEV evaporative emission standards. Compliance with these standards is a technical challenge for FFVs.[lii] These technical challenges are currently limiting the number of new vehicles that can be offered for sale as FFVs.[liii] Regulations adopted by ARB designed to reduce emissions from new vehicle models (both tailpipe and evaporative), along with revised ZEV standards, will require automobile manufacturer compliance with more stringent emission standards and growing percentage of ZEV and PZEV sales.[liv] Both of these sets of standards will create significant challenges for greater introduction of FFVs. The upper limit of FFV availability for new vehicle sales and incremental cost of California vehicle emission standards is unknown at this time.

Increasing fuel economy standards will require vehicle manufacturers to offer for sale a mixture of makes and models that will meet the more stringent corporate average fuel economy (CAFE) goals. The granting of California's waiver request by U.S. EPA on June 30, 2009, has allowed for the setting of limits on the GHG emissions from new vehicle sales in this state.[lv] One potential implication of this regulation is that the mix of new vehicles offered for sale in California will need to achieve ever-higher CAFE standards. As such, vehicle manufacturers may plan to offer certain makes and models of more fuel-efficient vehicles, such as: PHEV, fuel cell, direct injection diesel, and electric vehicles. None of these vehicles are FFVs. It is possible that vehicle manufacturer marketing decisions might preclude FFVs, setting the stage for a potential shortfall of new FFV vehicle availability in California in sufficient numbers to help meet compliance with the RFS2 renewable fuel obligations. This potential policy conflict should be examined in greater detail to determine if a potential FFV availability shortfall could occur.

E85 Pricing Issues

A growing market for E85 necessitated by ever-increasing mandated use of ethanol will need to adjust to the fact that E85 has less energy per gallon when compared to a gallon of E10. This energy difference can reduce the number of miles traveled per gallon from between 23 and 28 percent.[lvi] As such, the retail price of a gallon of E85 would need to be an equivalent percentage less than a retail gallon of E10 to ensure that an FFV operator would receive a gallon of equal value. For example, if a gallon of E10 was priced at $2.50, a gallon of E85 would need to be priced at between $1.80 and $1.95. However, in actual practice, FFV motorists have been consistently overpaying for E85 fuel.[lvii] Figure 3.16 tracks the national average retail prices from this study for both gasoline and E85. Staff has also included a gasoline-gallon equivalent (GGE) price for E85 based on an average fuel economy difference of 75 percent. As the chart indicates, consumers were paying more per gallon for E85 than fuel economy equivalent price. Consumers appear to have overpaid by an average of 29 cents per gallon during the study time frame. The overpayment ranged between 20 and 39 cents per gallon.

Figure 3.16: U.S. Gasoline and E85 Retail Prices July 2007 – June 2008



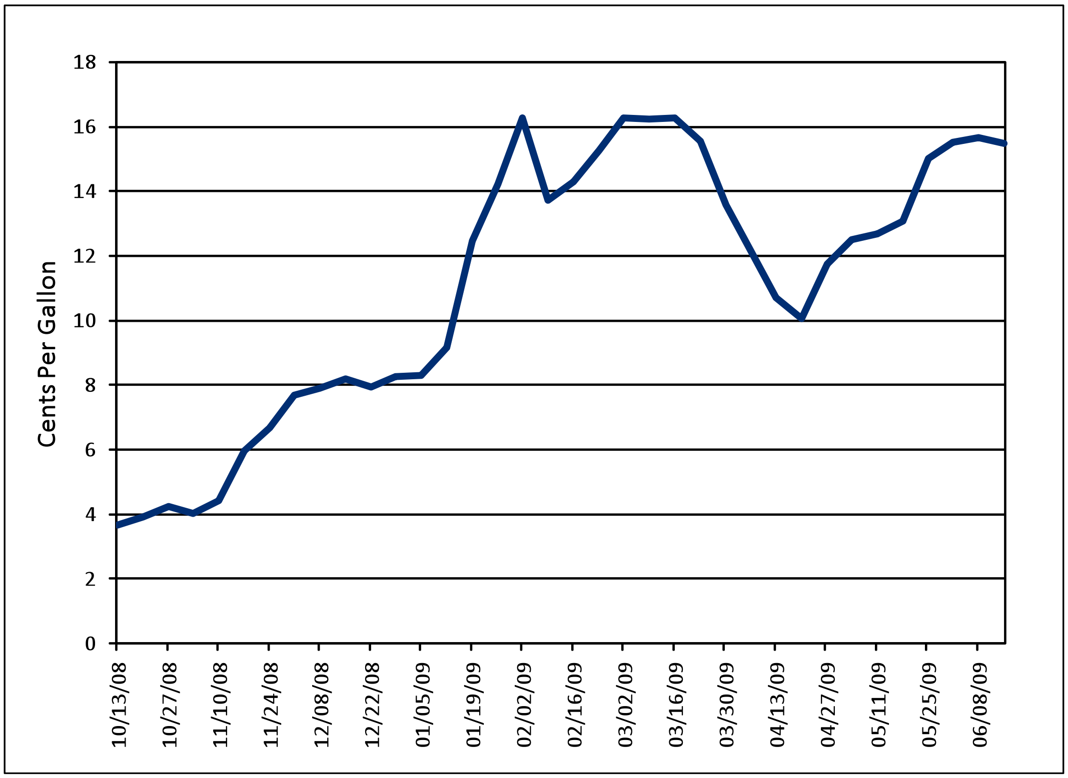
Source: National Renewable Energy Laboratory, Technical Report NREL/TP-540-44254, October 2008.

As California sales of E85 increase, there should be steps taken to help ensure that FFV motorists are receiving adequate pricing information at retail stations to put them in a position of making more informed fuel purchase decisions. Over time, FFV consumers may elect, on average, to pay a premium for E85 above the gasoline-gallon-equivalent (GGE) price. It is recognized that gasoline energy content varies on a seasonal basis, as well as from one refinery to the next. As such, GGE pricing through the use of an exact fuel economy equivalency ratio is not feasible and the use of an average equivalency factor could introduce significant variation about the true fuel economy differential at any point in time. Further, FFVs may exhibit fuel economy variability between various models. As an alternative method to provide California consumers with additional information, the Legislature should consider requiring retail station owners to affix labels on each face of E85 retail dispensers with language similar to “the fuel economy of an FFV using E85 is approximately 23 to 28 percent less when compared to E10.”

The lower fuel economy of E85 and resulting need to discount the price of this fuel to attract a sufficient level of demand implies that the suppliers of ethanol will need to consistently discount the wholesale price of E85. The need to provide consistently discounted ethanol for E85 blending could place downward pressure on ethanol wholesale prices and further depress ethanol producer profitability. This is one of the reasons that several ethanol producer stakeholders are pushing to have the ethanol blend wall increased from 10 to 15 percent by volume so that ethanol can be sold at or near gasoline values rather than being discounted. It should be noted that, in a non-mandated market setting, E85 retail stations and availability of FFVs allow for a type of ethanol pricing “floor,” meaning that as the discount between ethanol and gasoline increases, the economic incentive to blend additional volume of E85 on a discretionary basis rises allowing a greater quantity of ethanol to be sold into the fuel market (higher demand for ethanol producers). However, this discretionary market scenario will likely not develop as E85 sales in California will need to increase significantly to maintain compliance with mandated RFS2 “fair share” blending requirements.

The only possible exception to this outlook is the potential economic benefit of excess RINs.[lviii] The RFS2 program requires the tracking of renewable fuel use such that all obligated parties are able to verify compliance through sufficient levels of renewable fuel use or the acquisition of excess RIN credits from other market participants who have exceeded their "fair share" blending levels. Excess RIN credits have an economic value that has fluctuated between 3.7 and 16.3 cents per gallon (CPG) between October 2008 and June 2009. (See Figure 3.17.) RIN values have averaged 13.6 CPG for the first half of 2009. However, these RIN credit levels may not be sufficient to overcome the economic value of the fuel economy differential (44 to 56 CPG for $2.00 gasoline), even if one assumes that the blenders receiving the RIN credit revenue will be willing to pass some of that money back through to ethanol producers in the form of higher wholesale ethanol prices.

Figure 3.17: RIN Values October 2008 – June 2009



Source: Oil Price Information Service (OPIS).

It is clear from recent history that excess RIN credits can be viewed by the holder as an additional revenue stream that can be used to help offset costs and maintain sufficient profit levels. However, the party who holds title to the RINs can be unclear, and this uncertainty complicates compliance strategies for various parties.[lix] E85 blending in California is currently a practice involving other marketers who are not refiners. In this circumstance, the non-refiner blender can accrue RIN credits and their associated economic value that can be sold to either RIN aggregators, refiners, or other obligated parties. As California transitions to increased sales of E85 necessitated by RFS2, an imbalance between refiners' ethanol blending obligations and actual ethanol blending could widen if other market participants are the entities primarily blending and delivering the E85 to retail. Under this scenario, refiners would need to purchase an increasingly greater number of excess RIN credits to ensure compliance. In fact, the RINs embodied in the E85 could also be passed along to the retailer, who has no obligation to blend ethanol. Either way, it is likely that the cost of acquiring these RIN credits will be passed along to consumers in the form of higher prices over the long term by those parties forced to acquire excess credits (such as refiners).

LCFS and Changing Mix of Renewable Fuel Types

The ARB adopted the LCFS regulations on April 23, 2009. The regulation is intended to reduce the per gallon carbon intensity (as measured by both direct and indirect life cycle carbon emissions) of gasoline and diesel fuel by 10 percent between 2010 and 2020.[lx] The LCFS is expected to necessitate changes in the type of ethanol blended in California. Traditional ethanol (corn-based ethanol from the Midwest) has an average carbon intensity that is slightly higher than that of the base gasoline used to blend with the ethanol (referred to as CARBOB). As such, it is likely that this type of ethanol (currently supplying nearly 100 percent of California's needs) will fall from favor as early as 2011 (the first year for LCFS compliance). Therefore, other types of ethanol that have lower carbon intensity values will probably become more desirable as refiners and other obligated parties strive to achieve compliance with the RFS2 and LCFS simultaneously. Although the carbon intensity reductions appear modest, the anticipated trend of shifting from one type of ethanol to others will create potential supply and logistical challenges that could be difficult to overcome and probably result in higher compliance costs that will be passed along to consumers.

As is the case with gasoline, the lower per-gallon carbon intensity requirements of diesel fuel are expected to necessitate greater use of biodiesel to levels higher than the "fair share" biodiesel obligations associated with the RFS2. The magnitude of this increased use of biodiesel is not yet quantified since the carbon intensity values of various types of biodiesel fuels have yet to be finalized. The Energy Commission will continue to assess potential biodiesel supply and infrastructure issues as new information becomes available.

Assuming that there are no credits available from overcompliance and purchase of alternative vehicle credits, staff estimates that the LCFS for gasoline will greatly increase demand for Brazilian ethanol over the near to mid-term, while also necessitating expanded use of E85. As is the case with the federal RFS regulations, there is also a "disconnect" regarding the LCFS and the lack of any requirements for retail station owners and operators to provide a commensurate level of E85 availability. Assuming also that the ethanol blend wall in California remains at 10 percent by volume over the forecast period, staff estimates that various types of ethanol will have limited use as a blend in E10. The lower the carbon intensity of ethanol, the longer it will be used as a blend in E10. Table 3.4 depicts the various types of ethanol and how long they can be used absent over-compliance and acquisition of offsetting credits.

Table 3.4: LCFS – Complying E10 Blends

Gasoline with 10 Percent Ethanol (**E10**)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Midwest Wet Mill (60% NG and 40% coal)										
Midwest Dry Mill - Dry DGS (NG)										
Midwest Dry Mill - Dry DGS (80% NG and 20% Biomass)										
Midwest Dry Mill - Wet DGS										
Midwest Dry Mill - Wet DGS (80% NG and 20% Biomass)										
California Dry Mill - Dry DGS (NG)										
California Dry Mill - Dry DGS (80% NG and 20% Biomass)										
California Dry Mill - Wet DGS (NG)										
California; Dry Mill - Wet DGS (80% NG and 20% Biomass)										
Brazilian Sugarcane - Average Production Process										
Brazilian Sugarcane (Cogeneration Credits)										
Brazilian Sugarcane (Mech. Harvesting & Cogen. Credits)										

Sources: California Air Resources Board (ARB) and Energy Commission analysis.

Based on the information in the above table, certain types of ethanol are increasingly difficult to blend in gasoline as E10 without acquisition of LCFS credits (from low-carbon vehicles) or over-compliance. Brazilian ethanol may be blended in E10 for several years (up through 2016) without carbon credit offsets. California ethanol is viable in E10 blends for up to four years before it would need to be exported for use outside California or blended as E85. Finally, Midwest ethanol blending would be most limited, only able to be blended for a couple of years assuming the ethanol plant had wet DGS as a coproduct. Lastly, early use of Brazilian ethanol can enable a smaller portion of Midwest ethanol to be used for a longer period in E10 blends. However, the ratio of Midwest-to-Brazil ethanol declines to zero by 2017.

Since refiners and other obligated parties still need to achieve compliance with RFS2 "fair share" renewable fuel use, companies will need to examine other options for ethanol use in California besides blending with gasoline at a concentration of 10 percent by volume (E10). Increasing the concentration of ethanol in gasoline can reduce the overall carbon intensity of the blended gallon as long as the ethanol being used has lower carbon intensity than the base gasoline. Increasing use of E85 allows obligated parties to use various types of ethanol over a longer period. Table 3.5 shows the additional number of years that specific sources of ethanol can be used in a gallon of E85 for reducing the gasoline carbon intensity.

Table 3.5: LCFS – Complying E85 Blends

Gasoline with 85 Percent Ethanol (**E85**)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Midwest Wet Mill (60% NG and 40% coal)										
Midwest Dry Mill - Dry DGS (NG)										
Midwest Dry Mill - Dry DGS (80% NG and 20% Biomass)										
Midwest Dry Mill - Wet DGS										
Midwest Dry Mill - Wet DGS (80% NG and 20% Biomass)										
California Dry Mill - Dry DGS (NG)										
California Dry Mill - Dry DGS (80% NG and 20% Biomass)										
California Dry Mill - Wet DGS (NG)										
California; Dry Mill - Wet DGS (80% NG and 20% Biomass)										
Brazilian Sugarcane - Average Production Process										
Brazilian Sugarcane (Cogeneration Credits)										
Brazilian Sugarcane (Mech. Harvesting & Cogen. Credits)										

Sources: California Air Resources Board (ARB) and Energy Commission analysis.

As the table indicates, blending ethanol in E85 (under most circumstances) can achieve full per-gallon compliance with the LCFS without the need for any offsetting carbon credits. The only exceptions are California ethanol facilities that have dry DGS coproducts and certain sources of Midwest ethanol.

In future years, the decreasing per-gallon carbon intensity requirements for gasoline will necessitate using types of ethanol with ever-lower carbon intensities. Currently, Brazilian sugarcane ethanol has the lowest carbon life-cycle rating of all of the different types of ethanol that are currently being produced at commercial-sized facilities.[lxi] Lower-carbon intensity pathways for Brazilian ethanol production that employ reduced field residue burning or increased cogeneration from bagasse could achieve LCFS compliance over a longer period. The demand for this type of ethanol is expected to be strong as refiners and other market participants work toward compliance with the gasoline LCFS. As such, the quantity of ethanol that may be available from Brazil for import into California over the near term is of great importance but associated with significant uncertainty.

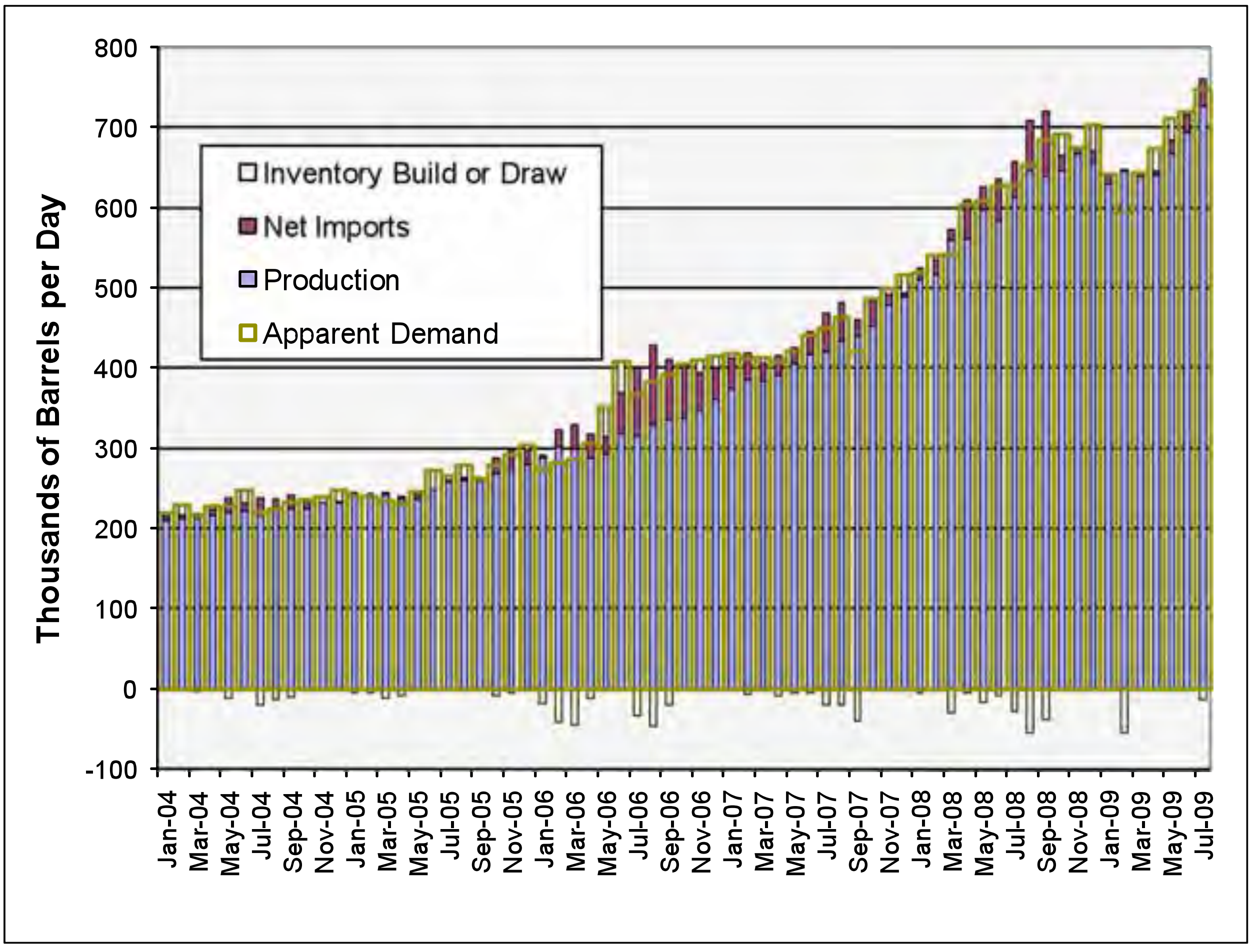
Additional pathways with lower carbon intensities can extend the length of time that ethanol can be used in gasoline blends for either E10 or E85. Verification of lower carbon intensity pathways is expected to continue over the next couple of years. This is especially the case once cellulosic ethanol and diesel fuel production is achieved and verified on a commercial scale. However, lack of information at this time precludes any analysis as to how beneficial those improvements could be in helping achieve LCFS compliance. Other "non-fuel" LCFS compliance options, such as the purchase of vehicle credits, can also extend the use of ethanol in gasoline blends or reduce the need for expanded E85 use.

Ethanol Supply Outlook

U.S. Ethanol Supply Outlook and Issues

Increasing demand for ethanol as a transportation fuel has been met by expansion of domestic production capacity, fluctuating quantities of imported ethanol, and inventory build or draws as necessary to balance out demand. Figure 3.18 shows supply and demand for U.S. ethanol between January 2004 and July 2009. Ethanol demand set another record in July 2009 of 748 thousand barrels per day (TBD). The demand for ethanol is expected to continue growing over the forecast period due to mandated blending quantities stipulated by the federal RFS2.

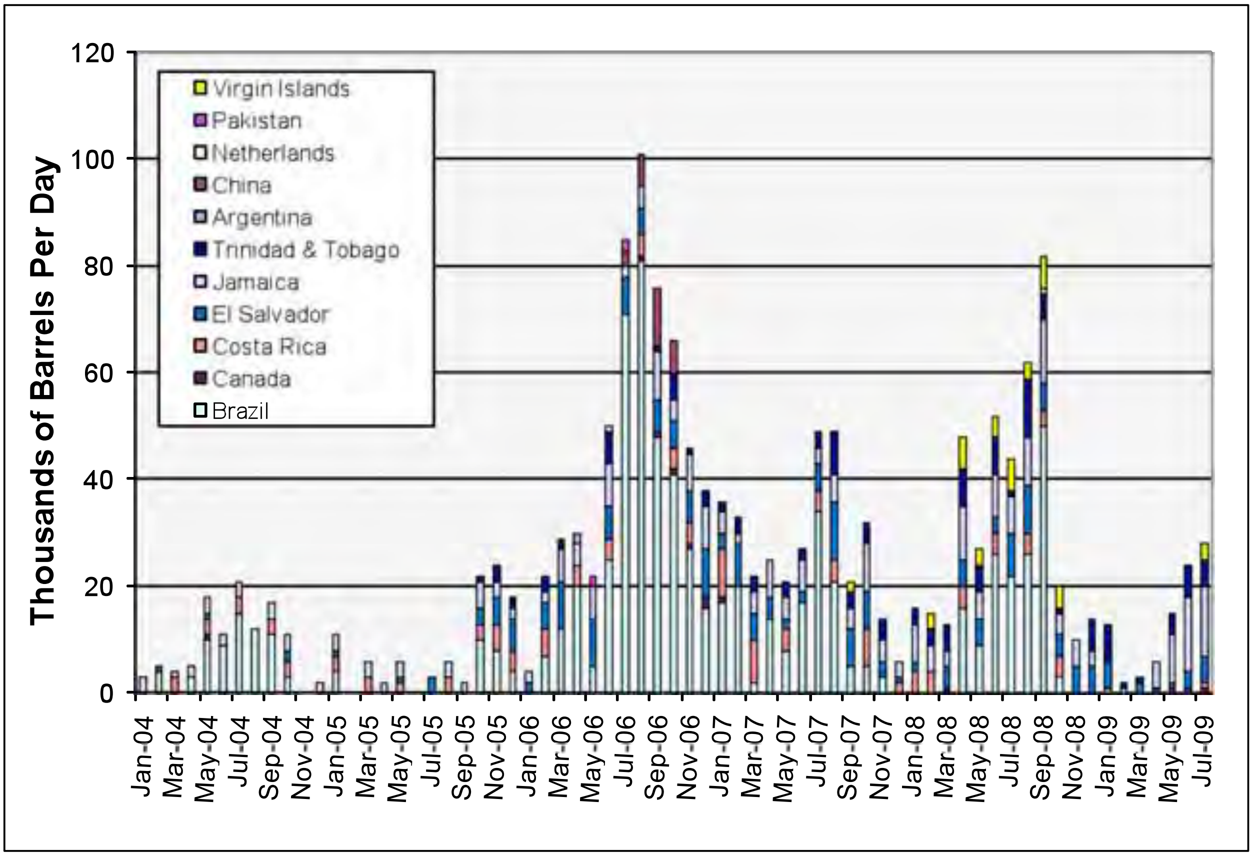
Figure 3.18: U.S. Ethanol Supply and Demand January 2004 – July 2009



Sources: Energy Information Administration (EIA) and Energy Commission analysis.

As the chart indicates, net imports of ethanol play a lesser role in the total supply picture. However, one of the key importers of ethanol over the last couple of years (Brazil) is expected to play a more pivotal role as demand for ethanol with lower carbon intensity grows in response to the California LCFS and the RFS Advanced Biofuels requirements. Figure 3.19 shows monthly U.S. net imports of ethanol between January 2004 and July 2009. Ethanol imports peaked at 100 TBD during August 2006. However, the oversupply of domestic ethanol and relatively low prices in the United States have reduced ethanol imports to modest levels during the first seven months of 2009.

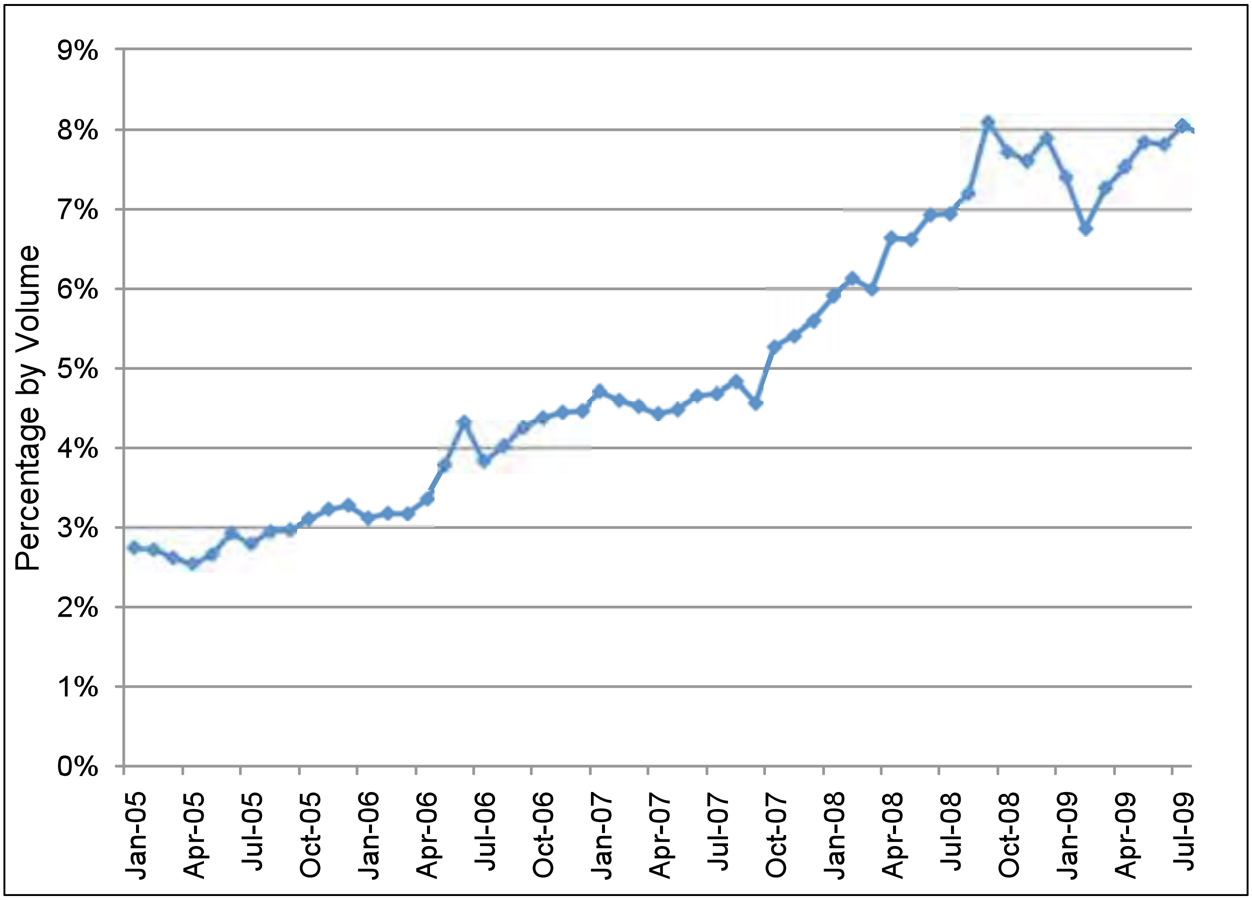
Figure 3.19: U.S. Net Ethanol Imports January 2004 – July 2009



Sources: Energy Information Administration (EIA) and Energy Commission analysis.

Increasing production and imports of ethanol over the last several years have resulted in a growing percentage of this renewable fuel displacing gasoline. When measured as a concentration in finished motor gasoline, ethanol use has steadily grown from approximately 3 percent by volume during 2005 to 8 percent by volume by July 2009. (See Figure 3.20.) The average concentration of ethanol in finished gasoline is expected to continue rising due to the federal RFS mandated use requirements.

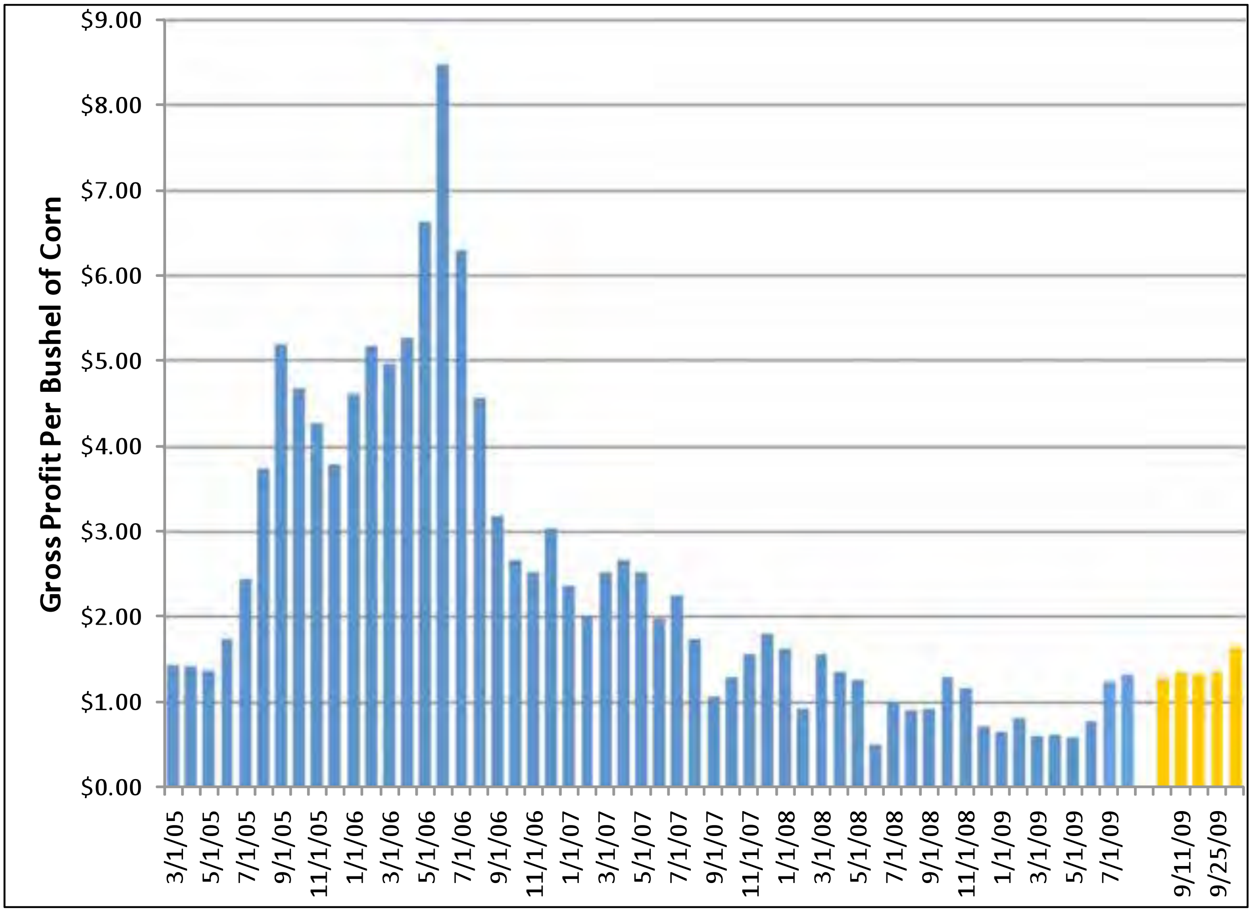
Figure 3.20: U.S. Ethanol Concentration in Finished Gasoline



Sources: Energy Commission analysis.

Several national and most California ethanol producers have recently been forced to shutter their operations due to a climate of sustained, poor production economics primarily brought about by a national oversupply of ethanol production capacity. Figure 3.21 tracks an aggregate measure of ethanol plant gross margins and shows that production economics have been significantly reduced from the highs of more than $5 per bushel of corn processed during 2006 to less than $1 per bushel during the early months of 2009.

Figure 3.21: U.S. Ethanol Industry Profitability March 2005 – October 2009

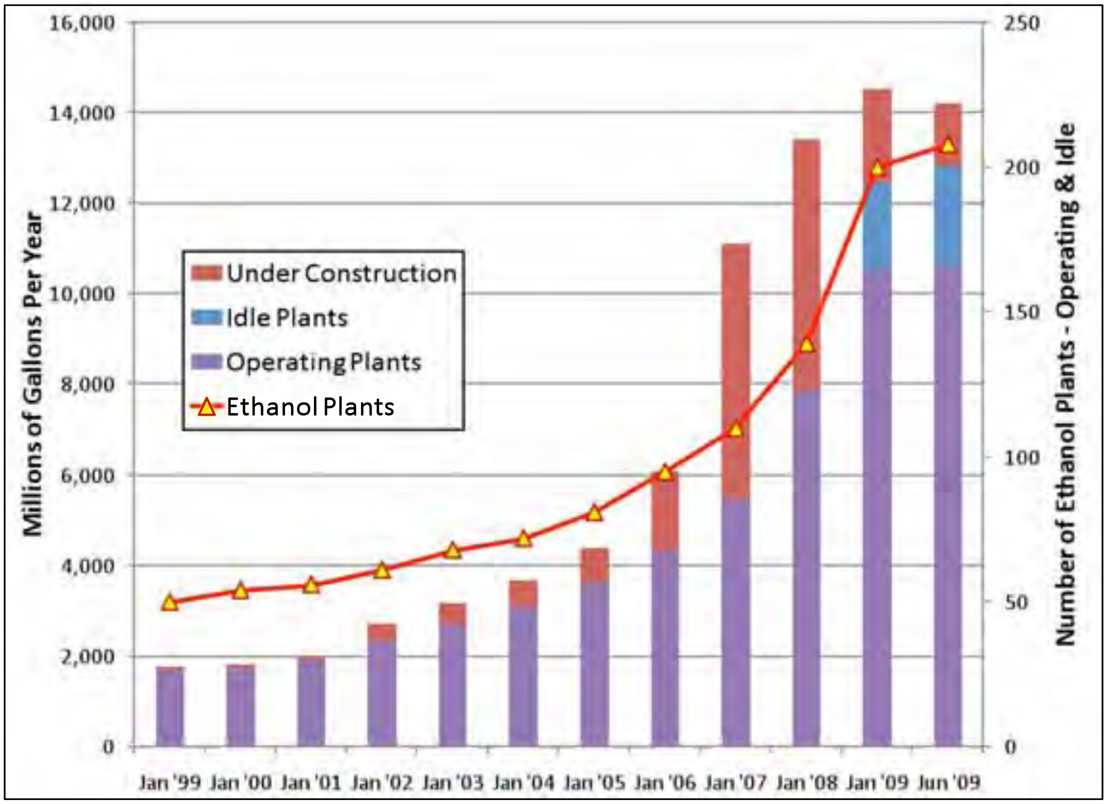


Sources: USDA - National Agricultural Statistics Service and Chicago Board of Trade (CBOT).

This development is expected to be temporary as demand for ethanol is forecast to significantly increase over the next several years as a consequence of the federal RFS regulation. In time, the oversupply of ethanol will be reduced, and the profitability of the industry will likely improve. In fact, ethanol production economics showed signs of improvement during the summer and early fall of 2009, and these improved conditions may enable a number of idled facilities to resume operations. The ethanol market has experienced other periods of economic difficulties associated with changing cost structures, market price differentials between gasoline and ethanol, and evolving markets for various coproducts.[lxii]

As of June 2009 there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States.[lxiii] Figure 3.22 shows the annual ethanol plant capacity for the United States broken down by operating, idle, and under construction, along with the number of ethanol facilities. The overwhelming majority of these facilities use corn as their sole or primary feedstock (99.3 percent of active plants, 98.3 percent of idle plants, and 92.6 percent for facilities under construction). It should also be noted that not all ethanol plants that are under construction will be completed and begin operating.

Figure 3.22: U.S. Ethanol Plant Numbers and Capacities 1999-2009



Sources: Renewable Fuels Association (RFA) (January '99 – January '09) and Ethanol Producers Magazine (June '09).

Despite the recent poor economics for operating domestic ethanol plants, production capacity of conventional ethanol is expected to be adequate over the next several years as facilities resume operations and new producers come on-line after completing their construction projects. As indicated in Figure 3.22, there was 12.9 billion gallons per year of ethanol production capacity in place (either operating or idle) as of June 2009. Even if only 50 percent of the capacity under construction is completed within the next year, there will still be sufficient domestic capacity in place to meet the 2012 calendar year RFS2 obligations for corn ethanol.[lxiv]

However, the current supply availability of certain other types of domestic ethanol is quite limited. Cellulosic ethanol production capacity is less than 4 million gallons per year production capacity.[lxv] The proposed federal RFS2 regulations require 100 million gallons of cellulosic ethanol use in 2010 and 250 million gallons in 2011. Since there is less than 5 million gallons per year of cellulosic ethanol production capacity under construction (as of July 2009), it is unlikely that there will be sufficient cellulosic ethanol capacity in place to meet the RFS2 obligations in 2010. In fact, the largest prospective cellulosic diesel producer identified by U.S. EPA in its proposed RFS2 regulatory package, Cello Energy, has recently been found by a federal jury in Alabama as liable for a $2.8 million breach of contract and $7.5 million in punitive damages in a court case associated with its cellulosic diesel fuel process technology claims.[lxvi]

Therefore, U.S. EPA should delay the cellulosic obligations until commercial production capacity is actually operational. This concept would be similar to the biodiesel blending mandate in Oregon that is triggered only when a sufficient threshold of biodiesel production capacity is actually operational for a period of three months.[lxvii] Specifically, U.S. EPA could set the national cellulosic ethanol use requirement for each January 1, based on the level of commercial-scale nameplate capacity of operating facilities in North America as of the preceding July 1.

California Ethanol Supply Outlook and Issues

Currently, four of the six California ethanol facilities are idle with a collective production capacity of nearly 184 million gallons per year. Two of the California facilities, owned by Pacific Ethanol, are in Chapter 11 bankruptcy proceedings. The remaining two idle ethanol plants are temporarily closed due to poor economic operating conditions (costs are exceeding revenue streams). Chapter 11 proceedings could result in an auction of some of California's ethanol facilities to other companies. A recent example is Sunoco's purchase of an ethanol facility in New York for $8.5 million.[lxviii] The 100 million gallon-per-year-capacity ethanol plant originally cost $200 million to design, permit, and construct. It is possible that another company could purchase one or more of California's ethanol plants at a large discount and/or greatly reduced debt load sufficient to enable an immediate resumption of operations and their commensurate employment gains.

Idled California facilities are expected to resume operations sometime during 2010, if not earlier. However, for this analysis, all California facilities that are currently idle are assumed to be fully operational at their rated nameplate capacity of nearly 184 million gallons per year beginning January 2011.

Future projects to develop ethanol production that would qualify for Advanced Biofuels and Cellulosic classification continue to be permitted and discussed. However, none of these proposed projects has yet to begin construction. The potential production capacity for advanced biofuels ethanol production in California is estimated by staff at approximately 502 million gallons per year. The majority of these facilities would use sugar cane as the primary feedstock. With regard to cellulosic ethanol production projects, there are nine facilities that have been discussed with a combined capacity of 168 million gallons per year. Although these incremental volumes of planned ethanol production are significant, there remains substantial uncertainty concerning viability of these projects under the current poor ethanol economic conditions. Over the near-to mid-term period, it is likely that some of these facilities will begin construction. Since the magnitude of incremental production and timing of new facility operations is highly uncertain, staff has elected to exclude these estimated production capacity volumes from in-state ethanol availability. Over time, some portion of this planned capacity is expected to come on-line, but probably only a lesser percentage of the total within the next five years.

Brazil Ethanol Supply Outlook and Issues

Ethanol from Brazil is produced from sugarcane, rather than corn. Since sugarcane cannot be stored once harvested, ethanol production in Brazil occurs seasonally, necessitating storage of ethanol sufficient to last until the following harvest cycle.[lxix] Brazilian ethanol production is also tied closely with the production of sugar from the cane juice. This means that ethanol plants in Brazil can adjust the ratio of ethanol-to-sugar in reaction to local ethanol demand / prices, export ethanol market economics, and world sugar demand / prices. In contrast, most United States ethanol producers do not have the flexibility to alter ethanol production by switching to another product. Ethanol production in the United States is adjusted by altering the quantity of corn processed. Table 3.6 compares the differences in the ethanol industry between Brazil and the United States.

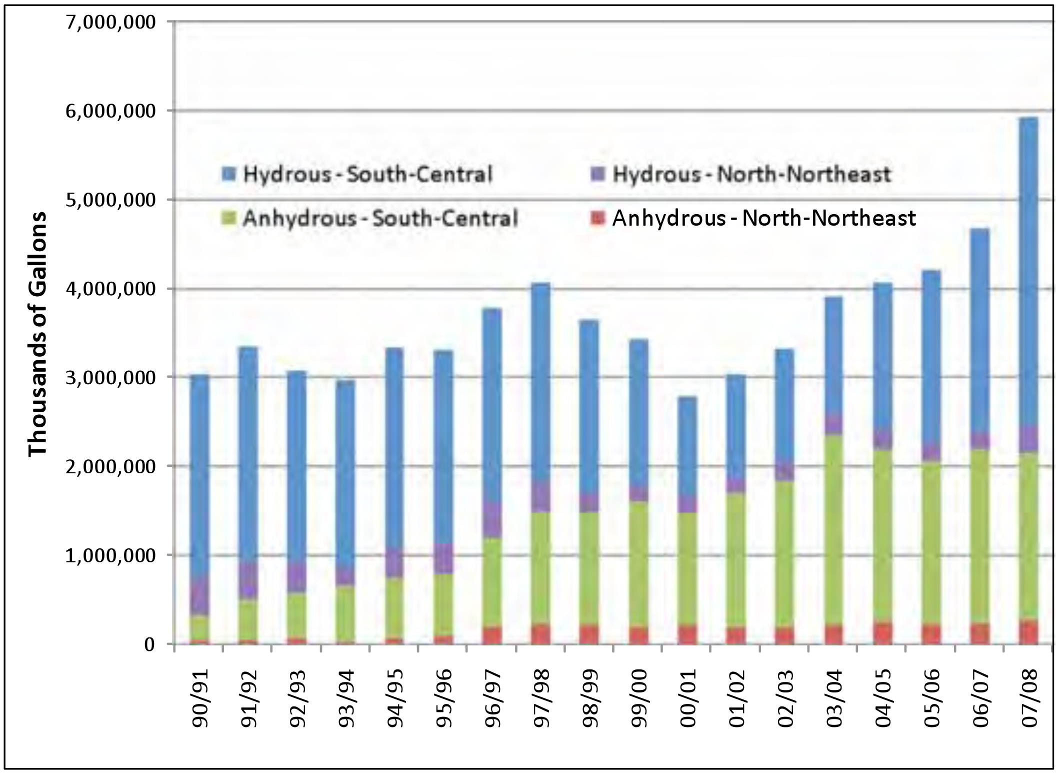
Table 3.6: Brazil and United States Ethanol Operations – 2008

2008 Comparison	Brazil	United States
Number of Ethanol Plants	96	193
Combined Number of Ethanol & Sugar Mill Facilities	229	
Total Ethanol Plants	325	193
Total Ethanol Production (Billions of Gallons)	5.9	9.2
Average Plant Production (Millions of Gallons/Year)	18.2	47.7
Ethanol Production Per Acre of Feedstock (Gallons)	678.5	432.4
Ethanol Plant Operation	Seasonal	Year-round
Long-Term Feedstock Storage	No	Yes

Sources: Various and Energy Commission analysis.[lxx]

As is the case in the United States, Brazil ethanol production has continued to increase, setting a record output level of 5.94 billion gallons during 2008. (See Figure 3.23.) Brazil produces two different types of ethanol, hydrous and anhydrous. Hydrous ethanol contains water in concentrations up to 5.6 percent by volume.[lxxi] This type of ethanol is used in FFVs designed to operate on fuels containing between 24 and 100 percent by volume or E100 (100 percent fuel ethanol). Hydrous ethanol is also exported to other countries (especially in the Caribbean) that further process (distill) the ethanol to remove most of the water before sending to the United States, duty free under the Caribbean Basin Initiative (CBI).[lxxii] All ethanol produced in Brazil in the initial steps of processing contains water that must be removed with an additional distillation step if the ethanol is destined for low-level gasoline blends in Brazil or final export destinations. Once the distillation step has been completed, the resulting product is referred to as anhydrous ethanol. This type of ethanol is suitable for blending with gasoline for use in low-level blends (up to 26 percent in Brazil and up to 10 percent by volume in the United States).[lxxiii]

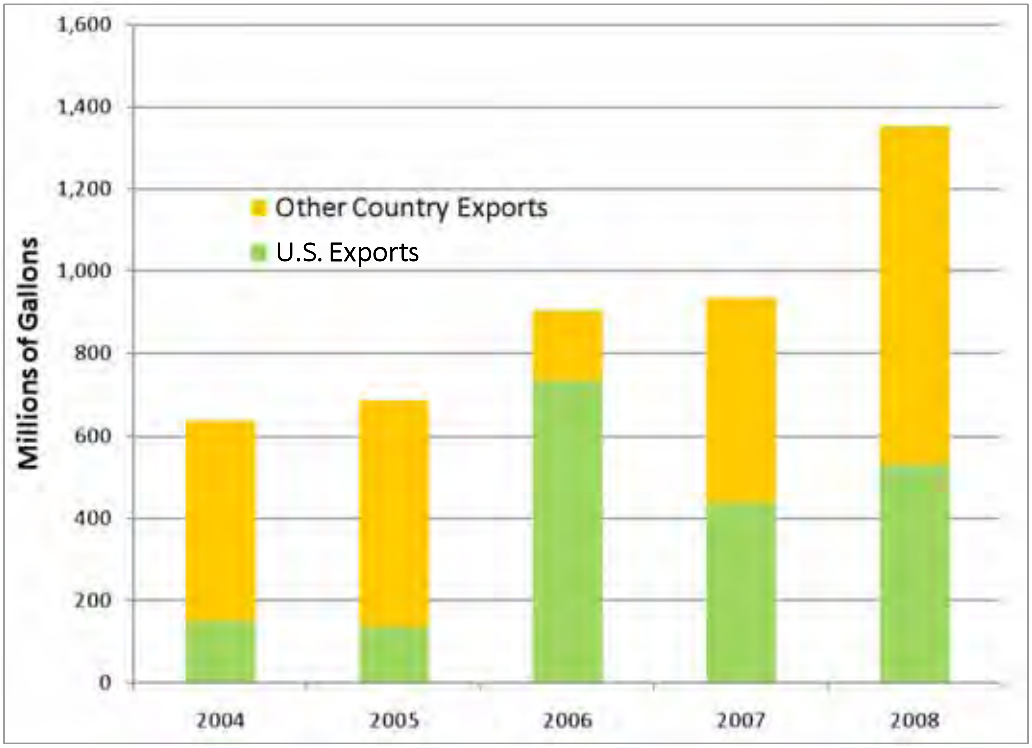
Figure 3.23: Brazil Ethanol Production 1990-2008



Sources: UNICA and Energy Commission analysis.

Production of ethanol in Brazil is determined by the interrelationship between various factors: minimum blending levels in gasoline as set by its Ministry of Agriculture; world sugar market demand, balances, and prices; outcome of sugarcane growing season; and the potential value of ethanol exports. Based on the interaction of these market components, there may or may not be ample excess supplies of ethanol available to export from Brazil in any given year. Over the last five years (2004 through 2008), Brazil has exported between 0.60 billion and 1.35 billion gallons of ethanol. (See Figure 3.24.)

Figure 3.24: Brazil Ethanol Exports 2004-2008

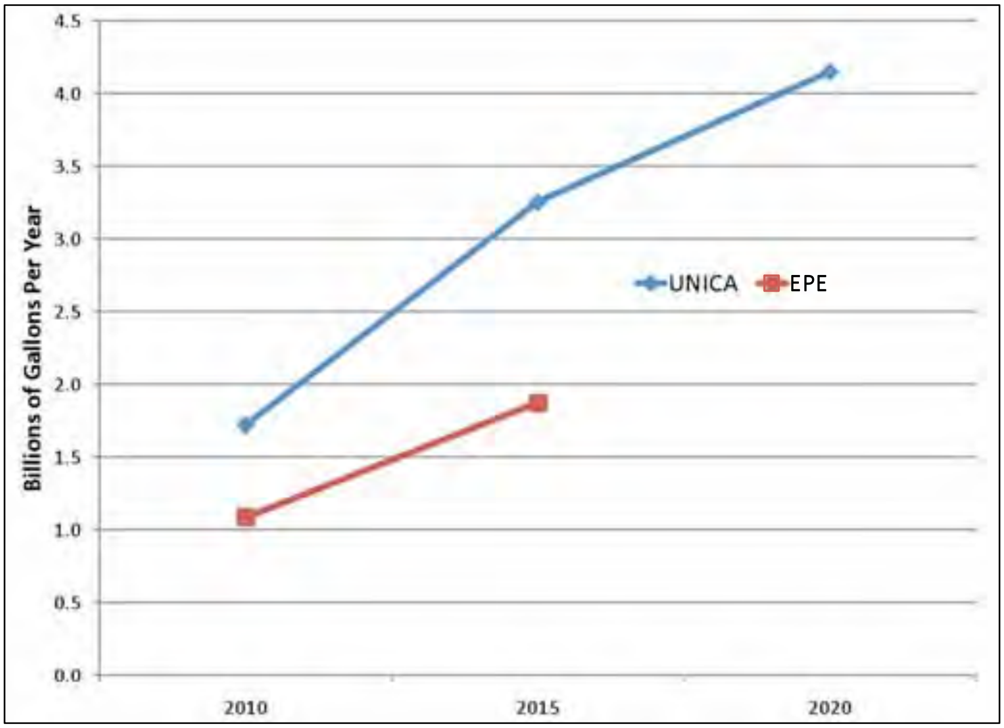


Sources: UNICA and Energy Commission analysis.

The level of Brazilian ethanol exports that arrive in the United States can vary depending on the relative price of ethanol in the U.S. market compared to the price of ethanol in other destination countries. Brazilian exporters of ethanol to the United States must pay two types of import duties, an ad valorem tax equivalent to 2.5 percent of the ethanol transaction price and a secondary import duty of 54 cents per gallon. Assuming ethanol is selling for $2 per gallon, the combined import duties for Brazilian ethanol would amount to 59 cents per gallon (ad valorem of 5 CPG + secondary import tariff of 54 CPG).[lxxiv] This form of protectionism increases the cost of supplying ethanol to the U.S. market and is a type of trade barrier not applied to other types of transportation fuel-related foreign imports such as crude oil, gasoline, jet fuel, and diesel fuel. Lately, a variety of stakeholders have been calling for the elimination of this ethanol import tariff, especially in light of the increased demand for Brazilian ethanol that is likely to materialize as a consequence of the federal RFS Advanced Biofuels requirement and California's LCFS for gasoline carbon intensity. Modeling work assessing the potential impact of removing the 2.5 percent ad valorem and the secondary import tariff suggest that the price of ethanol in the United States could be reduced from between 2.5 to 14 percent, a potential benefit to consumers.[lxxv]

The amount of excess ethanol that may be available to import from Brazil over the next several years is forecasted to grow to between 1.9 billion and 3.2 billion gallons by 2015.[lxxvi] Figure 3.25 illustrates estimates from the Brazilian Sugarcane Industry Association (UNICA) and Empresa de Pesquisa Energética or Energy Planning Agency of the Ministry of Mines and Energy of Brazil (EPE).

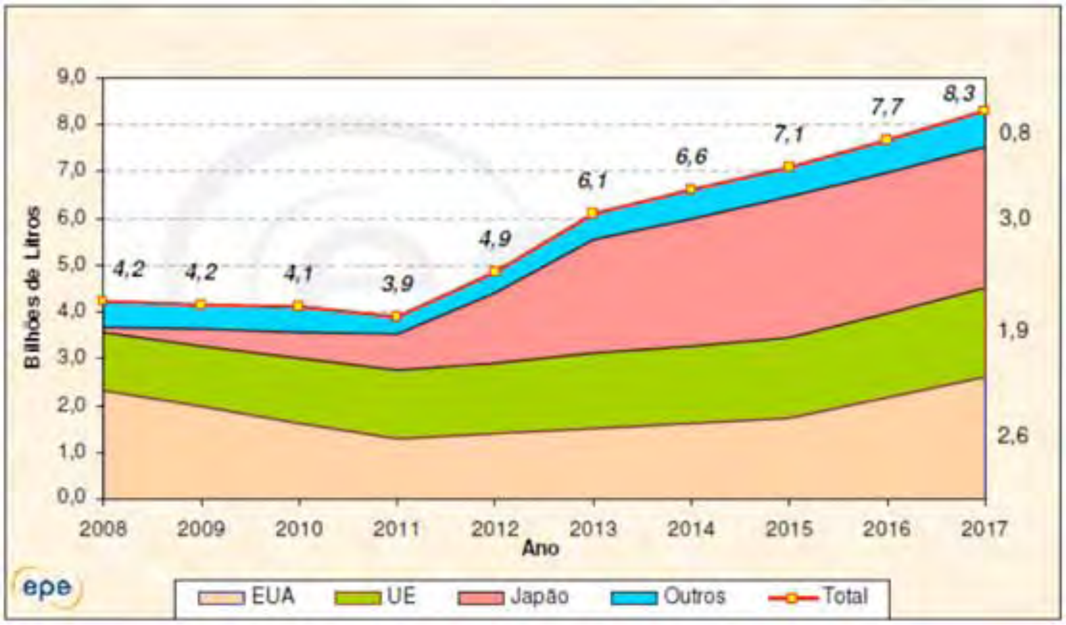
Figure 3.25: Brazil Ethanol Export Forecast



Sources: UNICA and EPE.

EPE's forecast of Brazil ethanol exports is more conservative than the Brazilian sugarcane industry association's outlook, especially when you consider that the EPE export estimate for 2010 is less than the 2008 total of 1.4 billion gallons. Although these forecast ethanol export volumes are sizable and could be used to achieve compliance with the Other Advanced Biofuels portion of the RFS2 requirements, keep in mind that Brazil has a certain volume of export obligations to locations other than the United States. One example is Japan, which is why EPE's forecast has a greater quantity of ethanol destined for that country. (See Figure 3.26 for the graph used in its report that contains the relative ethanol export quantities by destination country.)[lxxvii] The units of the chart are billions of liters, while "EUA" is the designation for the United States, "UE" for the European Union, and "Japão" for Japan.

Figure 3.26: EPE Forecast of Brazil Ethanol Exports by Destination

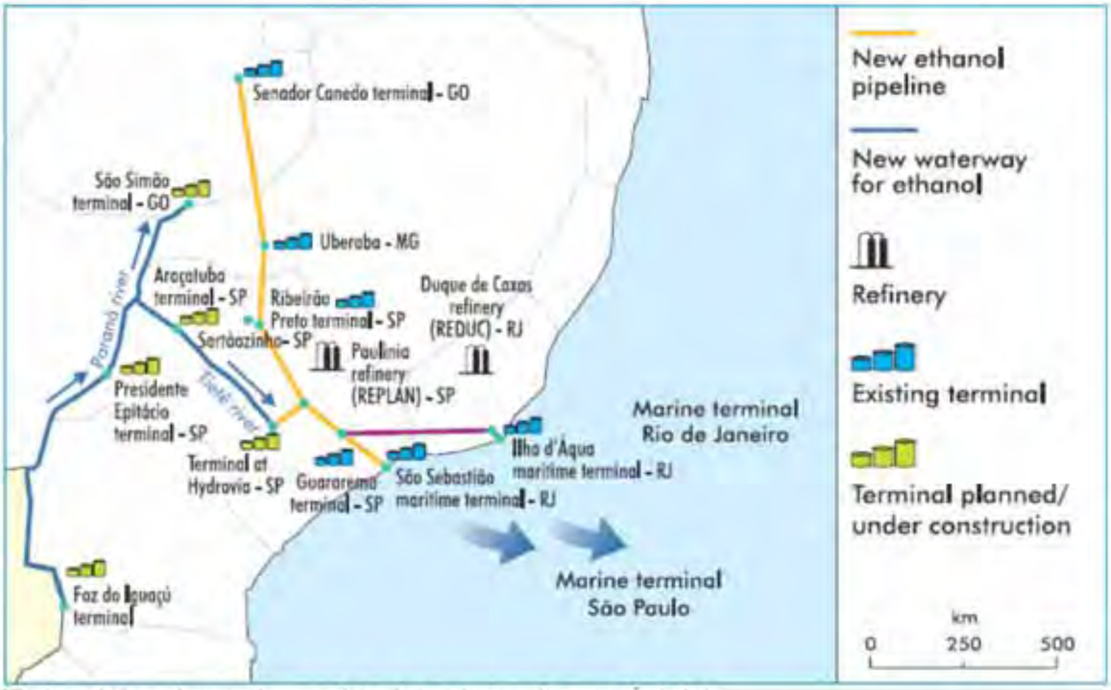


Source: *Perspectivas Para O Etanol No Brasil*, Empresa de Pesquisa Energética (EPE), page 33.

Other marketers throughout the United States will also be competing for Brazil ethanol as they attempt to comply with the Advanced Biofuels requirements of the RFS2 through acquisition and blending of this type of ethanol, rather than through the purchase of RIN credits from other marketers or RIN aggregators. Therefore, the market price for Brazil ethanol is expected to command a premium to California-sourced ethanol, which should be more valuable than conventional corn-based ethanol produced outside the state. The anticipated higher, yet unknown, prices are assumed to be passed along to consumers.

Brazil continues to develop an infrastructure that is designed to increase the quantity of ethanol that can be exported to destinations such as the United States. In fact, Brazil is the only country that transports ethanol over significant distances via pipelines that are also used to ship petroleum products. Figure 3.27 shows the existing and expanded infrastructure associated with an expansion of ethanol exports.

Figure 3.27: Expansion of Brazil Ethanol Export Infrastructure



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: State abbreviations are: GO – Goais; SP – São Paulo; MG – Minas Gerais; RJ – Rio de Janeiro.

Sources: Petrobras and *World Energy Outlook 2006*, page 478.

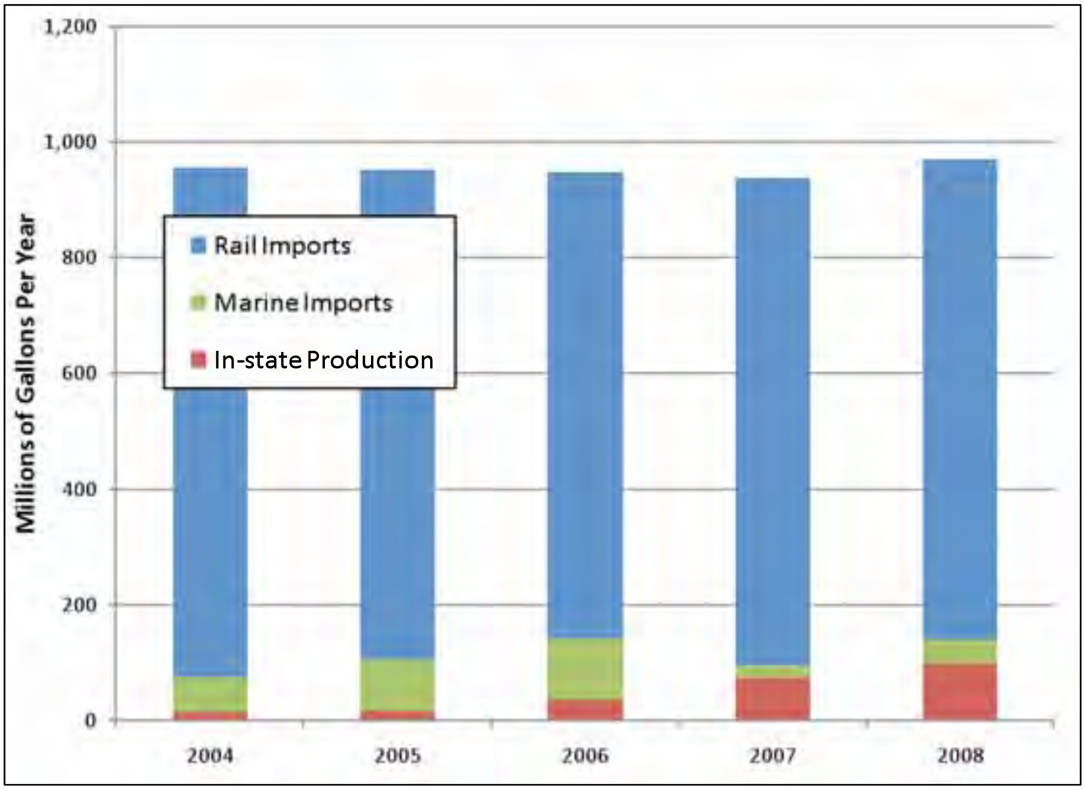
California Ethanol Logistics Outlook and Issues

It is clear that the quantity of ethanol used in California transportation fuels will increase over the next couple of years as refiners and other marketers react to higher levels for ethanol that will be mandated by the RFS2 requirements. In addition, the California LCFS is expected to further complicate matters by pushing obligated parties to select types of ethanol that have lower carbon intensities. At this time, ethanol produced from sugarcane in Brazil is the type of commercially available ethanol that has the lowest carbon intensity. As such, it is anticipated that California's logistical infrastructure for the importation and distribution of ethanol will need to be modified to enable a greater quantity and flexibility of ethanol imports within the next 6 to 18 months. In the case of alternative and renewable fuels, much of the infrastructure that will soon be necessary is not even in place. It is critical that the state expand upon the current petroleum fuel infrastructure to ensure a continued supply of transportation fuel for California and neighboring states, and that it build new infrastructure to ensure that California can meet its mandated renewable and alternative fuel goals.

Ethanol Rail Logistics

Currently, most of the ethanol used in California is imported from corn-based ethanol plants in the Midwest. The majority of these imports are via unit trains that consist of between 90 and 112 rail cars. This method of rail delivery is efficient in terms of transit time and costs as the unit trains usually receive priority use of the tracks and can transverse the distance from source to destination without stopping. The unit train receiving facility in Carson, California, supplies most of the ethanol to meet the needs of Southern California.[lxxviii] Northern California does not have a comparable type of rail receipt facility at this time and receives imports of ethanol via a combination of manifest rail cars and oceangoing marine vessels. Historically, the balance of ethanol supplies is obtained from California ethanol facilities. However, as discussed earlier, the majority of California's ethanol plants are temporarily shuttered due to poor economics. Figure 3.28 breaks down the sources of ethanol for California over the last five years. During this period, rail imports have accounted for an average of 88.4 percent of California ethanol supply, followed by marine imports (6.6 percent) and in-state production (5.0 percent). During 2008, rail imports represented 85.7 percent, followed by higher in-state production (10.1 percent) and marine imports (4.2 percent).

Figure 3.28: California Ethanol Supply Sources 2004-2008



Sources: Energy Information Administration (EIA), California state Board of Equalization (BOE) and Energy Commission analysis.

Ethanol Distribution Terminal Logistics

Kinder Morgan began accepting only base gasoline that will be used to blend E10 at all of their California distribution terminals on January 11, 2010.[lxxix] Since the majority of the gasoline distributed throughout California moves through some portion of the Kinder Morgan pipeline systems and refiners want to ensure that the type of gasoline they produce is compatible (to allow for volume exchanges and increased flexibility during unplanned refinery outages), it is expected that most if not all of California's gasoline market will switch to E10 during the first quarter of 2010.

Kinder Morgan also continues to make progress on its project to enable the receipt of ethanol unit trains into the Richmond area.[lxxx] Unlike the unit train facility in Southern California, this facility is designed to transfer the ethanol directly from the rail cars to the tanker trucks via a process called transloading.[lxxxi] Kinder Morgan has experience in this type of ethanol rail receipt and transfer operation as it transloaded 15,000 rail cars of ethanol in 26 markets throughout the

United States in 2007.[lxxxii] The completion and operation of this project should help ensure that Northern California will have sufficient capacity to receive ethanol via rail cars to accommodate the increase to E10 blending during the first quarter of 2010. However, as discussed earlier, the LCFS is expected to drive refiners and other obligated parties to seek out types of ethanol with lower carbon intensities, such as ethanol from Brazil. This anticipated import requirement could be necessary as early as the beginning of 2011.

Ethanol Marine Logistics

Marine imports of ethanol to California have been limited over the last several years due primarily to an abundance of ethanol production capacity in the United States and the import tariff for most sources of foreign ethanol. Consequently, the capacity to receive significant quantities of ethanol via marine vessel has not been needed. However, that situation could be altered due to the changing mix of ethanol sources and the potential impact on marine import infrastructure requirements. At this time, it is uncertain how much incremental ethanol could be imported into California via marine vessel. Over the short term, operators of marine import facilities could commit additional storage tanks for receiving ethanol imports. The conversion of storage tanks from one type of service (gasoline, diesel, or jet fuel) to ethanol service does not pose a technical difficulty. These types of decisions would reduce the ability of individual marine facility operators to import other petroleum products, unless overall import capacity was to increase.

If California were to transition to greater use of Brazilian ethanol, there are two pathways for this foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. Along these lines, Primafuel has received permits to construct a new marine terminal in Sacramento that is designed to import up to 400 million gallons of ethanol per year.[lxxxiii] At this time, construction has not been initiated. Reticence on the part of potential customers appears to be the primary hurdle at this time. The proposed Sacramento renewable fuels hub terminal would greatly increase the marine ethanol import capability of Northern California such that there should be sufficient capacity to receive Brazilian ethanol over the near to mid-term period.

Additional imports of Brazilian ethanol into California could also be accomplished via unit trains originating in another port city outside California. For example, ethanol from Brazil could be imported through the Houston ship channel and transferred to rail cars before delivery to California. Kinder Morgan is pursuing just such an endeavor that is referred to as the Deer Park Rail Terminal project that could be operational by late 2010.[lxxxiv] Development of this type of capability would increase the likelihood that sufficient capacity could be in place to import significant quantities of Brazilian ethanol.

Ethanol Trucking Logistics

Although California receives the majority of ethanol via rail cars from outside the state, only a few gasoline distribution facilities have the capability to handle rail cars full of ethanol. Instead, the overwhelming majority of California's distribution terminals that dispense gasoline receive all of the ethanol needed for blending via tanker truck deliveries that originate at the primary ethanol rail receipt hub terminals. As California moves to higher concentrations of ethanol in gasoline (E10) and an anticipated increase in E85 sales, a greater number of truck trips will be required to supply sufficient quantities of ethanol to all of these distribution terminals. An anticipated increase of more than 50 percent for the number of truck trips could place a temporary burden on trucking resources (both the number of qualified drivers and the number of tanker trucks rated to haul ethanol). Any logistical difficulties that may manifest themselves should be corrected within a couple of months as the industry quickly adapts to higher ethanol blending rates in California.

Ethanol Pipeline Logistics

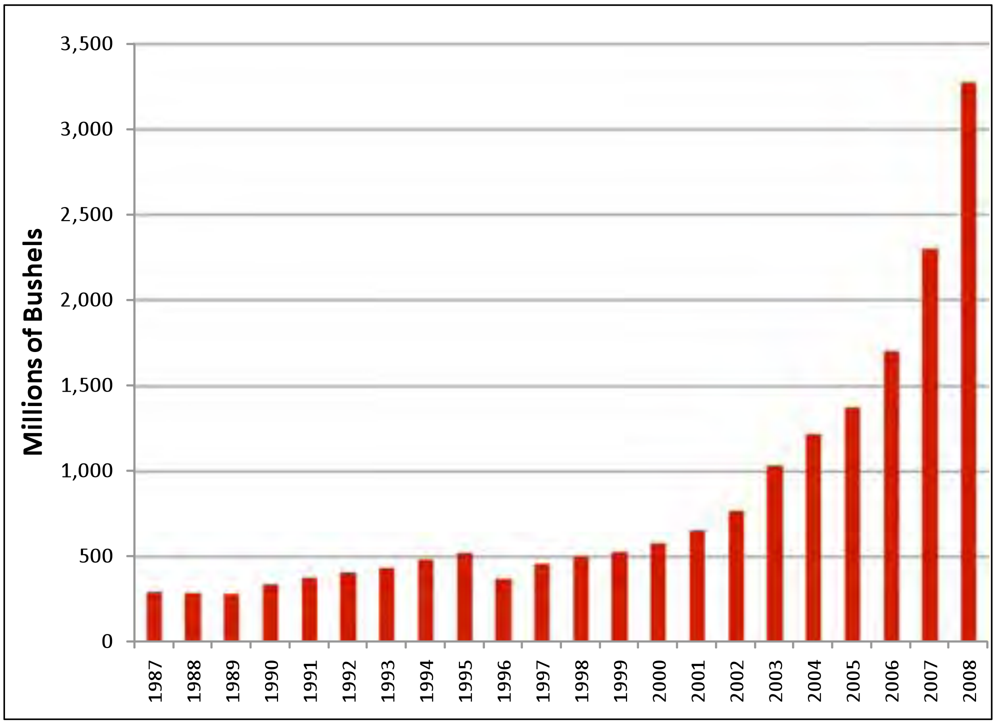
The last portion of the ethanol logistics distribution infrastructure involves the pipelines used to transfer transportation fuels from refineries to distribution terminals. Currently, no ethanol is shipped through any petroleum product pipelines that are also used to transport gasoline, diesel, or jet fuel. Kinder Morgan has demonstrated that ethanol can be successfully shipped in batches through their pipeline segment in Florida.[lxxxv] However, this practice is unlikely to be extended to California over the near to mid-term due to the increased age and complexity of the existing California pipeline system, as well as a higher probability of water in the pipeline system due to changes in the pipeline elevation (hydraulic profile).[lxxxvi] If over a longer period ethanol shipments do become an operational reality in California, the primary impact on ethanol logistical operations would be the reduction in truck trips from ethanol receipt hubs to all of the distribution terminals. However, the shipment of ethanol through California pipeline segments would also displace shipment capacity for other transportation fuels in those portions of the pipeline infrastructure at or near pumping capacity. In time, Kinder Morgan and other pipeline companies could make modifications to their pipeline distribution systems to increase pumping capacities if ethanol pipeline shipments were to occur in California.

This discussion would not be complete without mentioning a recent proposal to construct a pipeline dedicated solely to ethanol shipments. A pipeline company (Magellan Midstream Partners, LLP) and an ethanol company (POET) have signed a joint development agreement to “continue assessing the feasibility of constructing a dedicated ethanol pipeline.” The project is designed to gather ethanol from ethanol facilities located in the Midwest and transport the renewable fuel as far as 1,700 miles to the Northeast United States.[lxxxvii] The ultimate cost of this undertaking could be $3.5 billion and requires some level of federal loan guarantees. A similar concept for a dedicated pipeline in California would likely be economically unattractive since California does not have a large concentration of ethanol plants that normally sell their ethanol to markets that are over 1,000 miles distant.

Renewable Fuels and Agriculture

The majority of fuel ethanol in the United States is produced in facilities that use corn as the primary feedstock. As the demand for mandated use of ethanol continues to grow, so too does the demand for corn as a feedstock. Figure 3.29 illustrates the quantity of corn that was used annually to produce ethanol since 1987.

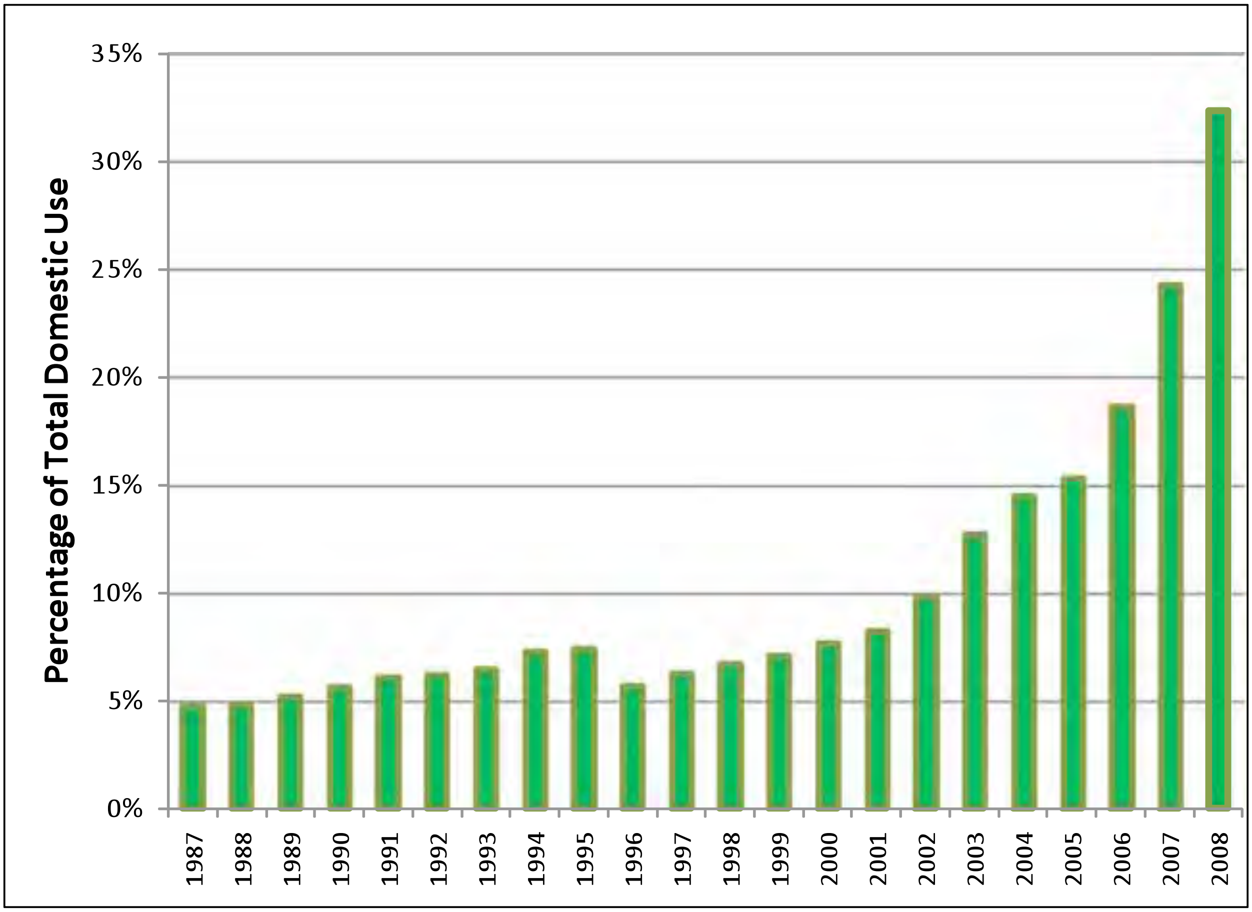
Figure 3.29: U.S. Corn Demand for Ethanol Production 1987-2008



Source: USDA - National Agricultural Statistics Service.

During the earlier years of ethanol use, corn demand for producing ethanol was a small percentage of total domestic use. However, the portion of corn required to produce ethanol has been increasing at an accelerated pace and accounted for approximately 32.3 percent of domestic corn use in 2008. Figure 3.30 shows the increasing use over the last 22 years.

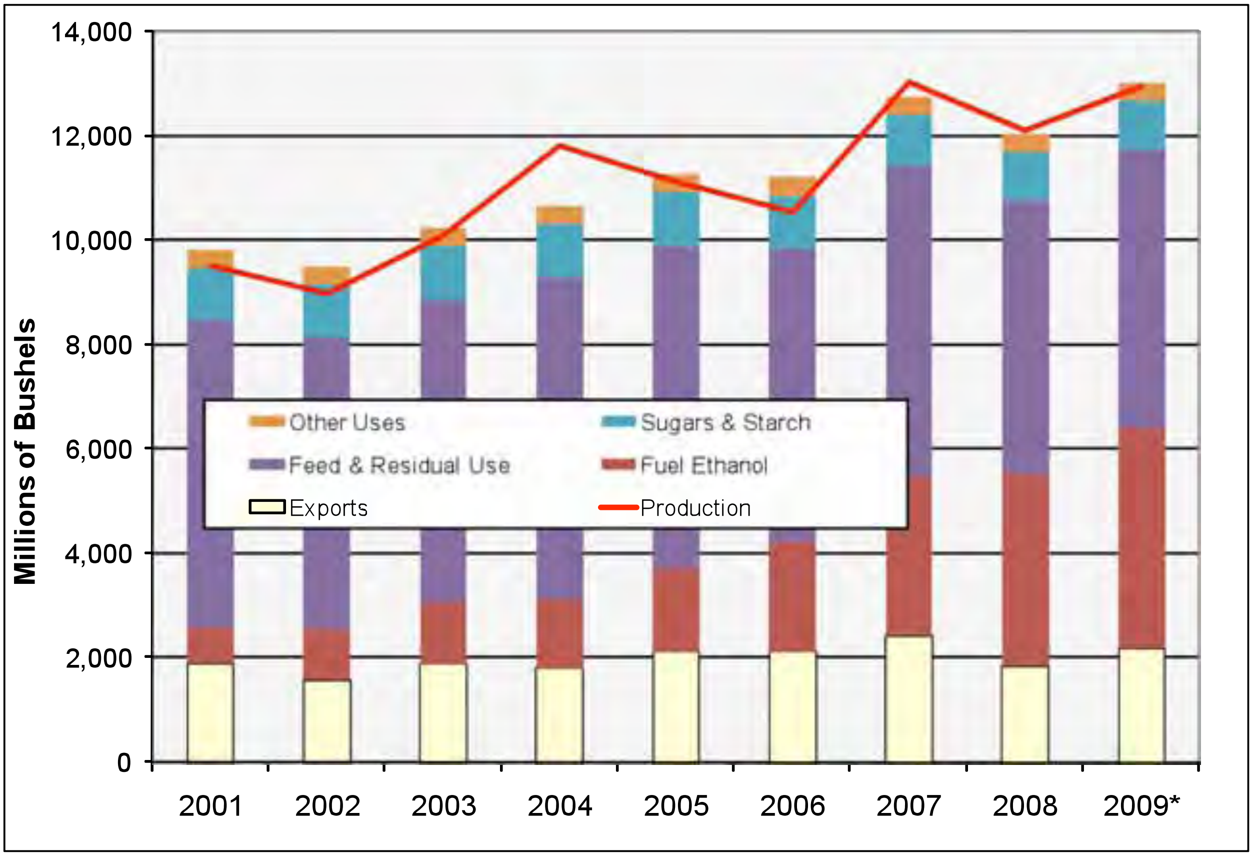
Figure 3.30: U.S. Percentage of Corn Demand for Ethanol Production 1987-2008



Sources: USDA - National Agricultural Statistics Service and the Energy Information Administration (EIA).

Other uses of corn (included as a feedstock for ethanol production) are shown in Figure 3.31 between 2001 and 2009. The 2009 values are USDA forecasts.

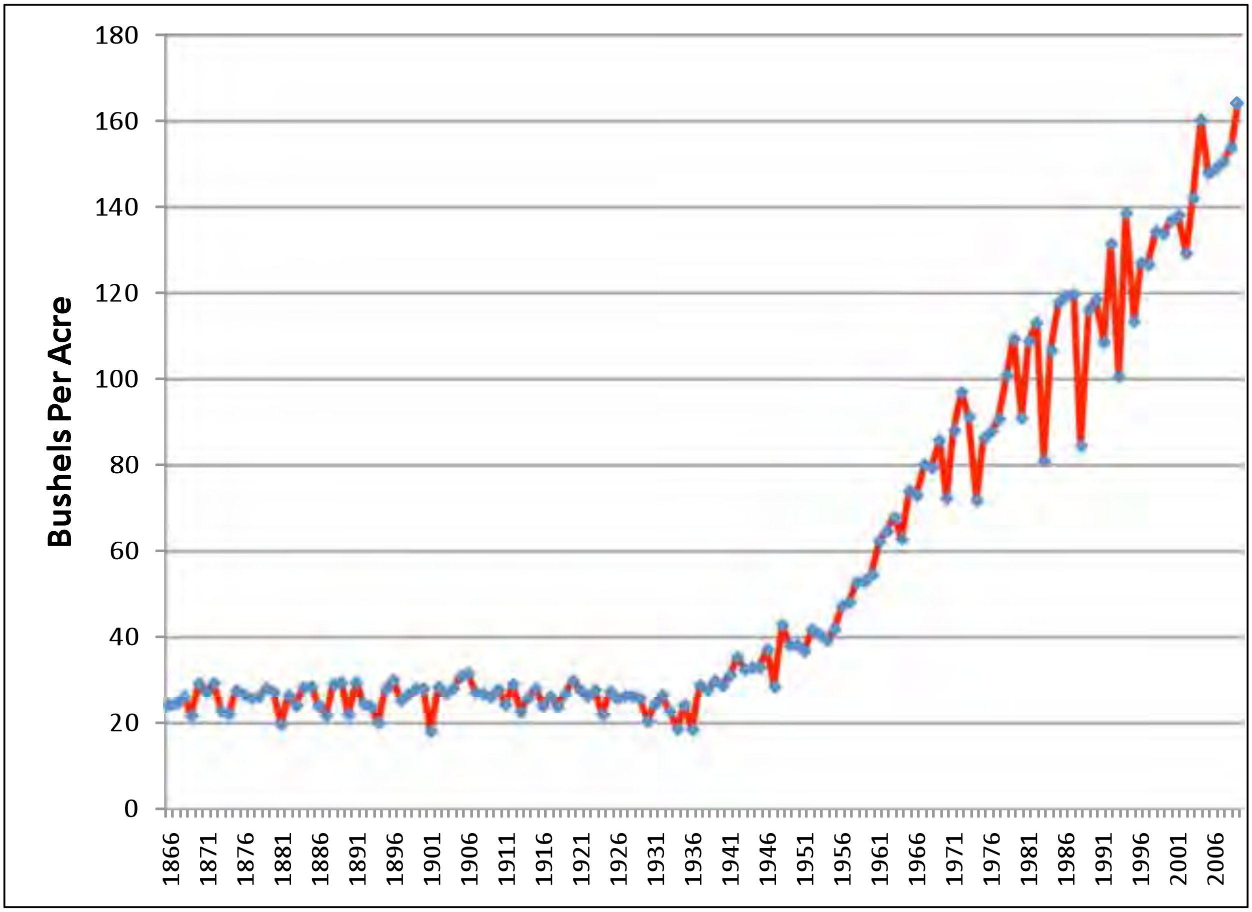
Figure 3.31: U.S. Corn Production and End Use 2001-2009



Sources: USDA - National Agricultural Statistics Service and Energy Commission analysis.

The ability of the agricultural markets to keep pace with the rapid demand to produce ethanol from corn has largely been accomplished via a continual improvement in the average yield of corn per acre. (See Figure 3.32.) In fact, USDA has forecast the yield for 2009 to average an all-time record of 164.2 bushels per acre.[lxxxviii]

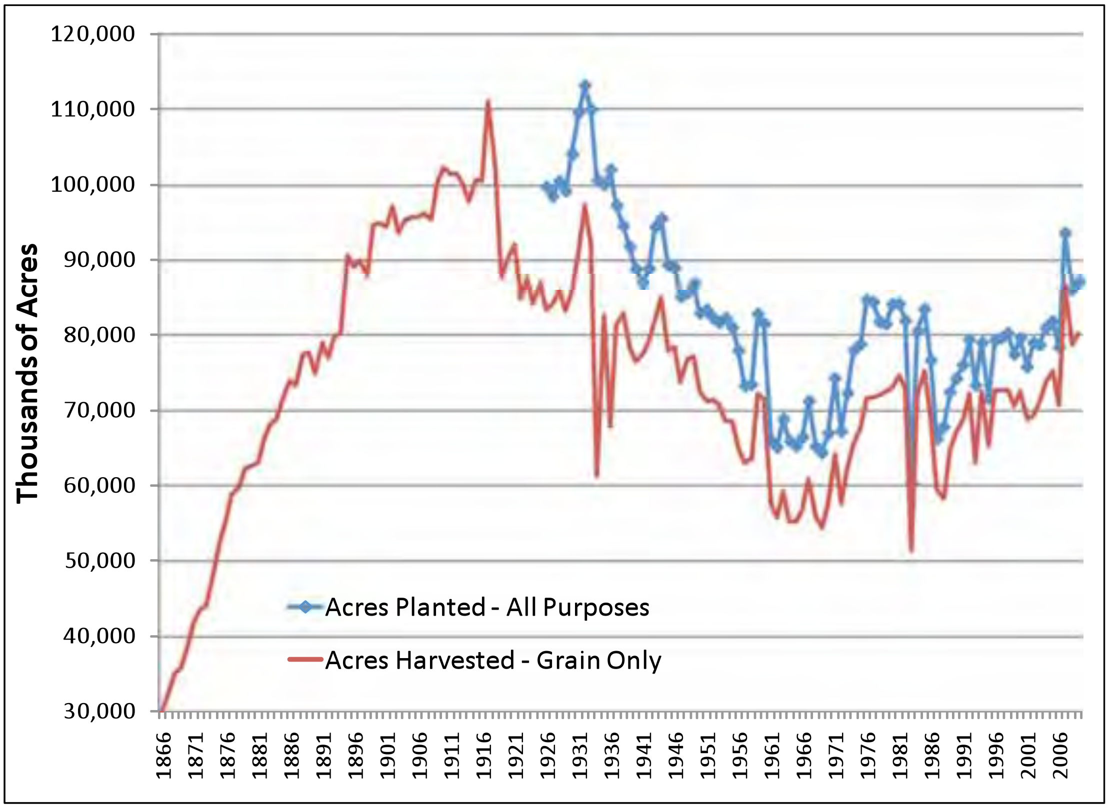
Figure 3.32: U.S. Annual Corn Yield 1866-2009



Source: USDA - National Agricultural Statistics Service.

The near-continuous yield improvement (as measured in bushels harvested per acre) has been accomplished through increased application of fertilizer up through the early 1980s, followed by improved strains of crops and use of geographic information systems (GIS) to allow for the more precise application of fertilizer and plowing techniques. All of these advances and improved practices have enabled greater production of corn without any significant expansion of the number of acres planted. In fact, the 78.6 million acres of corn harvested in 2008 is 32.3 million acres less than the record 110.9 million acres in 1917. Despite the lower total, 2008 corn production of 12.1 billion bushels was more than four times the 1917 production of 2.9 billion bushels. Figure 3.33 shows the progression of corn plantings between 1866 and 2009.

Figure 3.33: Acres of Corn Planted and Harvested 1866-2009

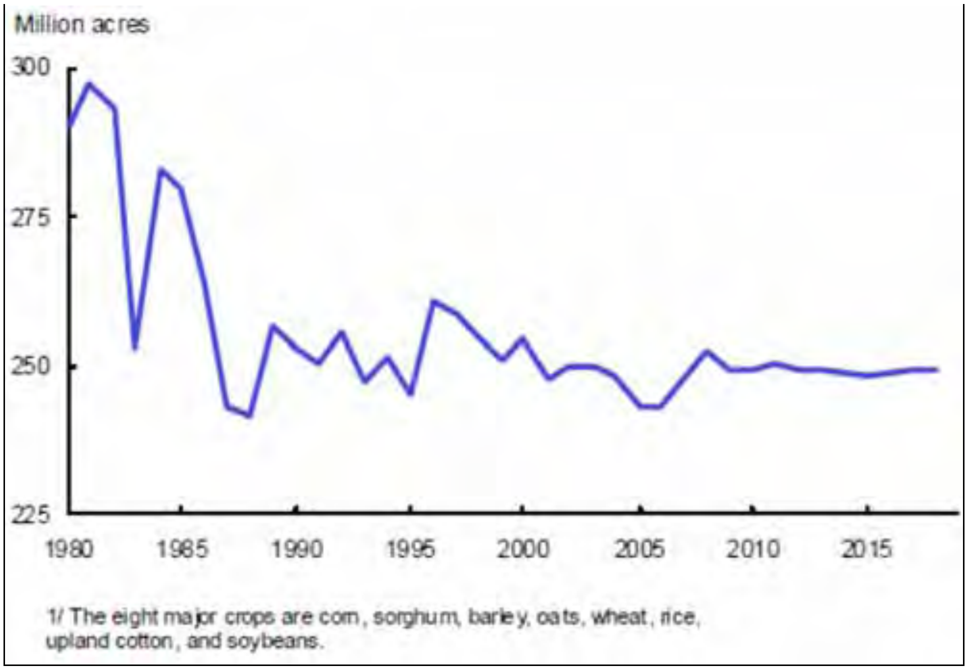


Source: USDA - National Agricultural Statistics Service.

The increased demand for corn to produce even greater quantities of ethanol is a near-certainty since the RFS-mandated ethanol levels allow for up to 15 billion gallons of ethanol per year to originate from facilities that use corn as a feedstock. One consequence of this growing demand for corn-based ethanol is that the quantity of corn required to produce up to 15 billion gallons per year of ethanol will be higher than the 3.27 billion bushels estimated to produce the 9.24 billion gallons of ethanol in 2008. Assuming the amount of corn required to produce one gallon of ethanol remains the same (approximately 2.8 gallons of ethanol per bushel of corn processed), the minimum corn demand to produce up to 15 billion gallons of ethanol could top 5.3 billion bushels by 2015. According to the USDA, the quantity of corn for production of fuel ethanol is forecast at 4.825 billion bushels for market year 2015/16.[lxxxix]

Potential deleterious impacts on other crops could occur if increased demand for corn for ethanol production were accomplished by expanding corn acreage by replacing other field crops, such as wheat and soybeans. Agricultural land in the United States is considered to be a somewhat finite resource. However, Congress does have the ability to adjust the maximum number of acres that are permitted to be included in the Conservation Reserve Program (CRP) through the passage of a revised farm bill.[xc] Figure 3.34 highlights the point that the USDA forecast is assuming flat projections for the total acres planted for the eight major crops over the forecast period.

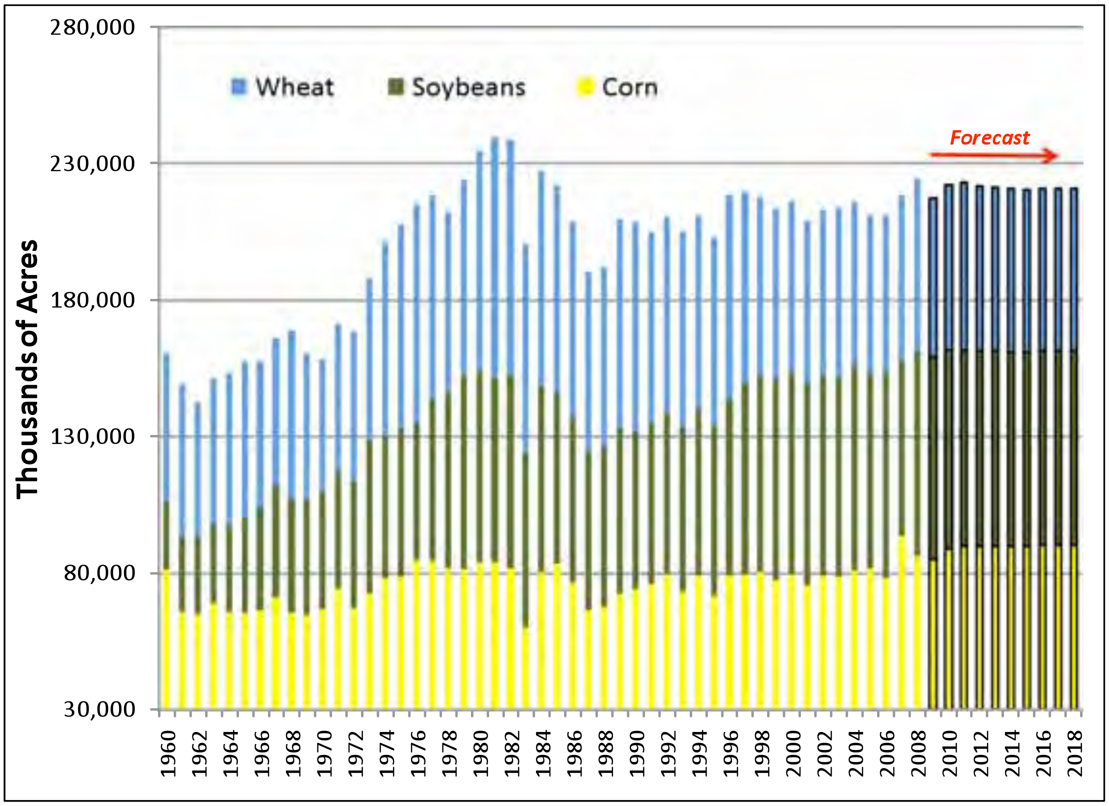
Figure 3.34: U.S. Major Crop Plantings 1980-2018



Source: USDA Agricultural Projections to 2018, February 2009, page 18.

Since the acres of farmland dedicated to major crops are expected to remain relatively unchanged over the next nine years, what does this trend portend for corn, soybeans, and wheat plantings that have been routinely characterized as interchangeable? Figure 3.35 shows the historical plantings for these three crops, along with the USDA forecast. As the chart illustrates, total acres for all three actually *decrease* by 1.7 percent compared to 2008, while corn acres planted are forecast to be 5.3 percent greater compared to 2008.

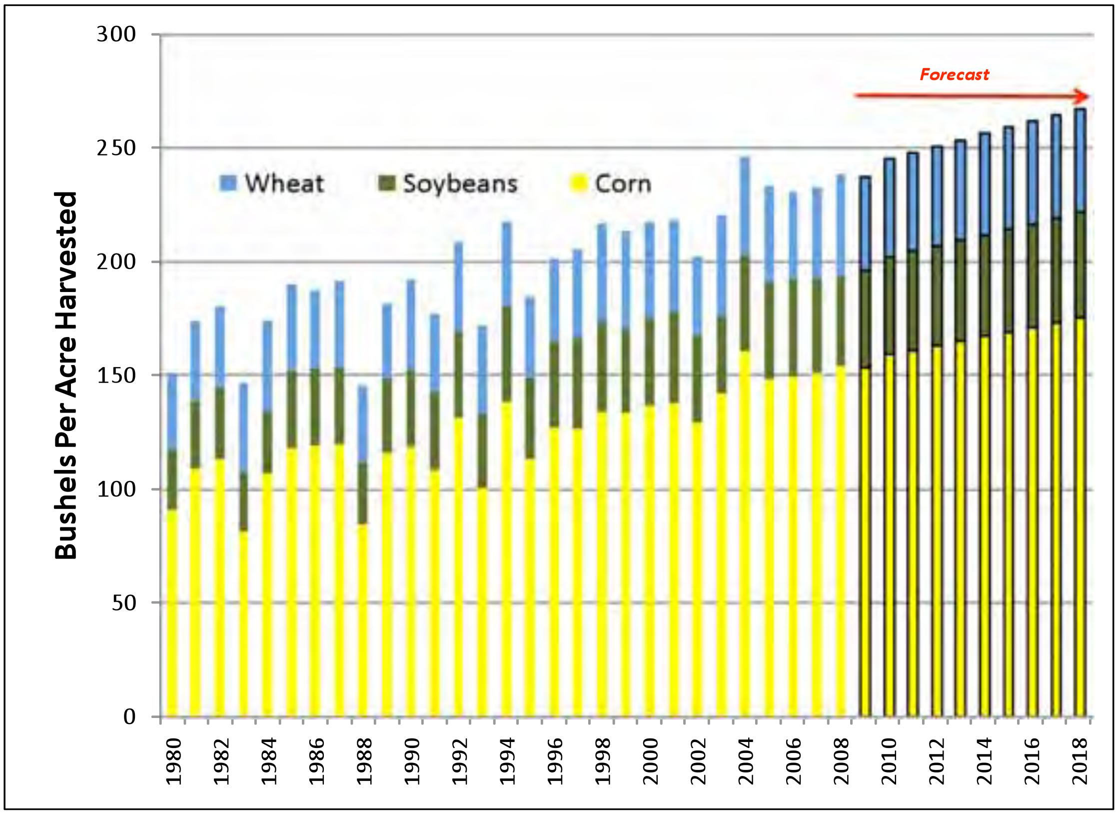
Figure 3.35: U.S. Corn, Soybean, and Wheat Plantings 1980-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009.

This USDA outlook means that the combined acres planted for wheat and soybeans will decrease by 6 percent by 2018 when compared to 2008. Therefore, it seems as though the expansion of corn planting will come at the expense of reduced wheat and soybean plantings. Although the planted acres are expected to decline over the forecast period, total production actually rises by 11.6 percent for soybeans but declines 7.6 percent for wheat between 2008 and 2018. This feat is accomplished through a continued improvement in the average production yield per acre over the forecast period. Figure 3.36 shows the respective annual yields for corn, soybeans, and wheat for both the historical and forecast period.

Figure 3.36: U.S. Corn, Soybean, and Wheat Yields 1980-2018

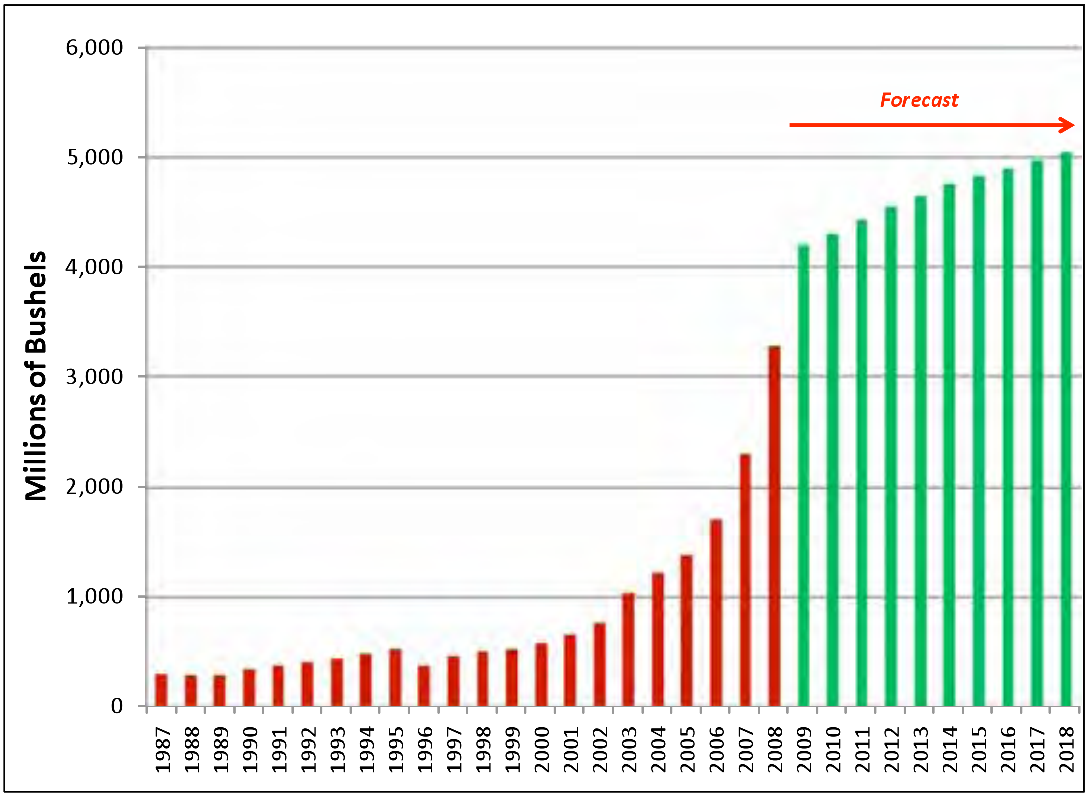


Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009.

Production yields as measured in number of bushels per acre harvested have been continually increasing for several decades due to improvements in agricultural practices and genetics. USDA assumes in its forecast that this trend of increasing yields will continue between 2008 and 2018. Corn yields are forecast to rise from 153.8 bushels per acre harvested in 2008 to 175.0 bushels per acre by 2018, an increase of 13.8 percent. Soybean yields are forecast to grow by 18.3 percent (39.3 to 46.5 bushels per acre), while wheat yields are forecast to rise by only 1.8 percent (44.9 to 45.7 bushels per acre) over the forecast period.[xci]

Although continuous yield increases in the forecast seem justified by the historical growth rates, actual yields for any particular crop during a growing season can be negatively affected by poor weather conditions (insufficient rains for dry-cropping or flood damage from severe storms) and increased levels of destruction from disease or pests. Therefore, any decrease in either yields or the number of acres planted over the forecast period could result in less production (in terms of bushels) for corn, soybeans, and other major crops as portrayed in the USDA projections. Lower-than-expected production of corn could raise market prices and negatively impact the profitability of ethanol plant operators. Figure 3.37 overlays the USDA corn demand forecast for ethanol production with the historical demand since 1987.

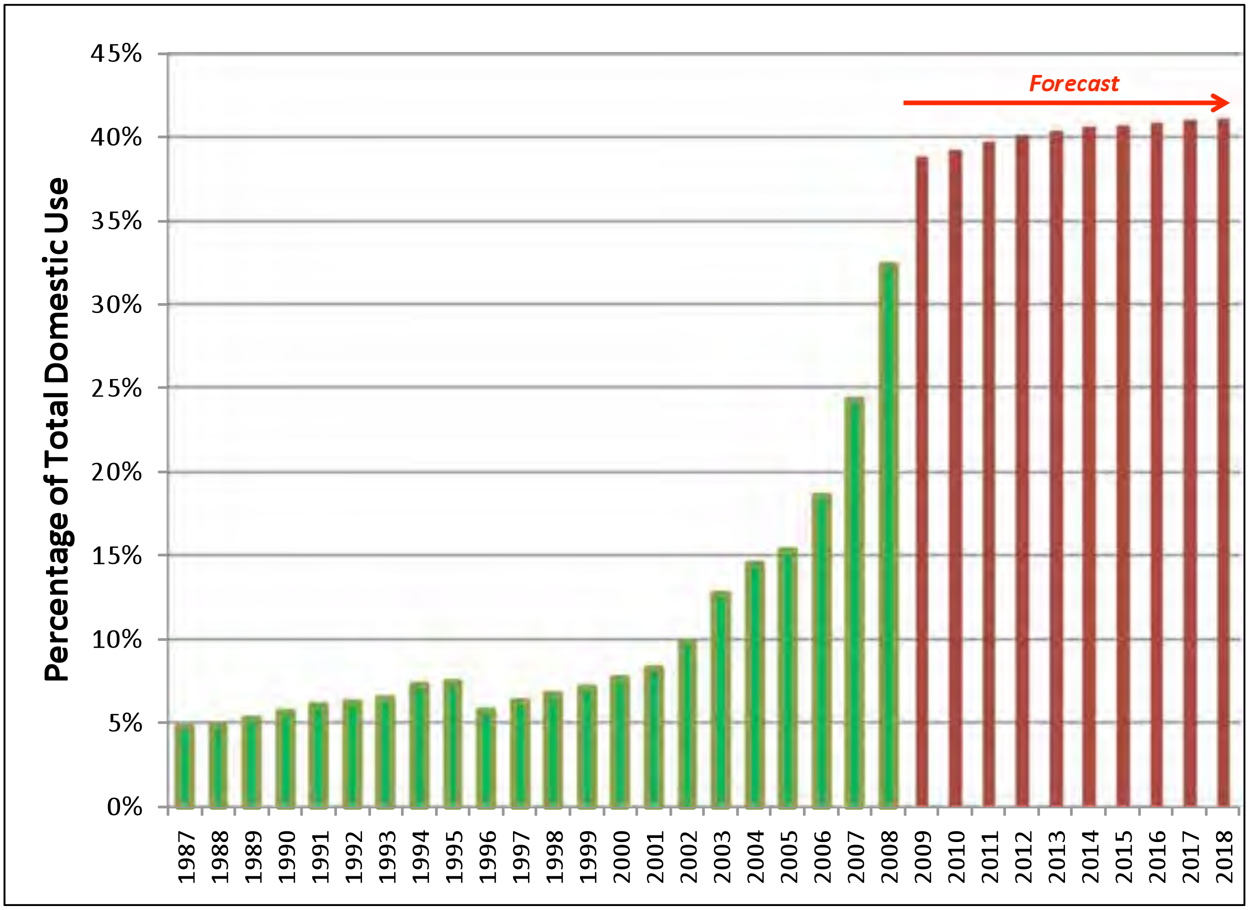
Figure 3.37: U.S. Corn Demand for Ethanol Production 1987-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009, page 33.

The rather dramatic increase in corn demand for producing ethanol does not appear as drastic when viewed as a percentage of total domestic use, as shown in Figure 3.38. As this chart indicates, the percentage nearly levels out at 41 percent since other uses of corn are also increasing over the forecast period, just not as quickly.

Figure 3.38: U.S. Percentage of Corn Demand for Ethanol Production 1987-2018



Source: USDA National Agricultural Statistics Service and Agricultural Projections to 2018, February 2009, page 18.

Other Potential Agriculture Issues

Various concerns regarding increased water use and higher fertilizer application rates associated with corn have been voiced by some stakeholders. Based on the most recent agriculture census by the U.S. Department of Agriculture (2007), the majority of corn is grown without the use of any irrigated water, solely dependent on rainfall during the growing season. In 2007, only 15.3 percent of corn acres were irrigated with the balance (84.7 percent) receiving no irrigated water.[xcii] It is not known if expanded production of corn will occur as a result of an even higher ratio of irrigated acres over the forecast period. Assuming the ratio remains fairly constant, increasing corn production due to higher mandated ethanol demand should primarily occur through expansion of dry cropping, rather than through increased irrigation. With regard to fertilizer use, staff examined USDA statistics and noted that the application rate per acre of corn for nitrogen has increased 6.2 percent between 1980 and 2005, while the average corn yield has increased 62.5 percent over the same period.[xciii] The continued improvement of corn yields is primarily a consequence of other improvements unrelated to increased use of nitrogen per acre.

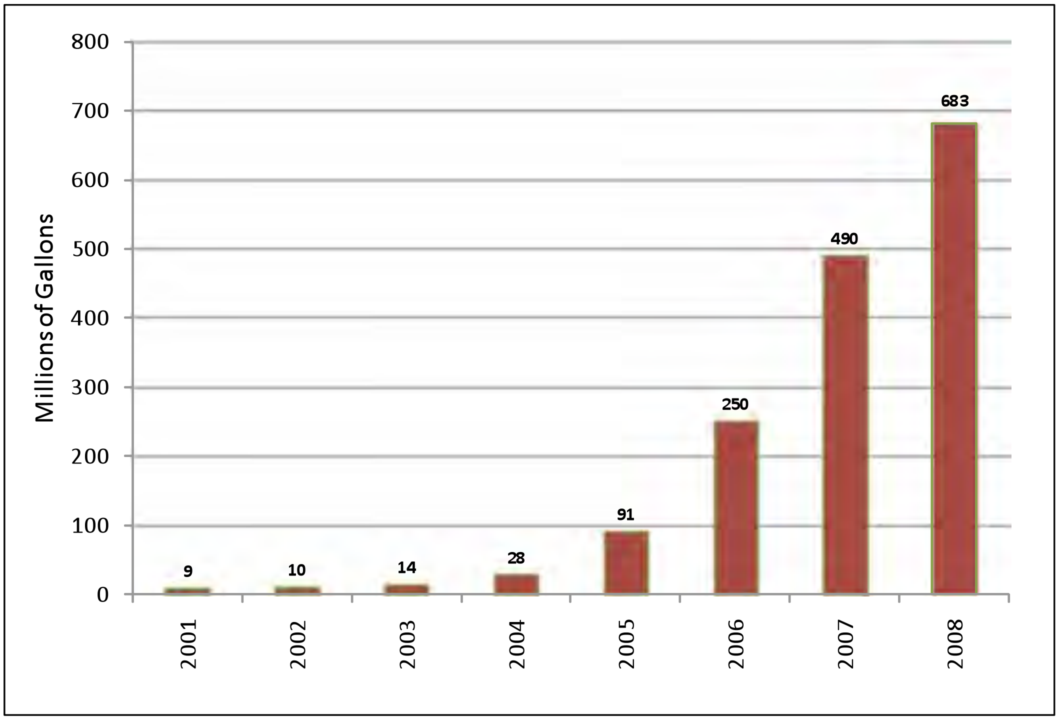
Biodiesel Overview

Biodiesel is a general term used to describe mixtures of diesel fuel with varying concentrations (between 2 and 20 percent) of biomass-based distillate. Early use of biomass-based distillate dates back to at least 1900, when Rudolph Diesel used peanut oil in a diesel engine at the World's Fair in Paris.[xciv] The earliest reference to biodiesel (ethyl esters of palm oil) is from a 1937 Belgium patent, followed by application in a commercial urban bus route between Brussels and Leuven, Belgium, during the summer of 1938.[xcv] Biodiesel use continued up through World War II as a necessity brought about by shortage and security. Increased availability of relatively inexpensive petroleum-based diesel fuel essentially eliminated biodiesel use until a resurgence spurred by the 1990 Clean Air Act Amendments and the Energy Policy Act of 1992.[xcvi] Currently, retail sales of biodiesel in California are quite modest but will likely increase for the same reason as ethanol (the state LCFS and the federal RFS2).

Blenders of biodiesel are permitted to vary the concentration in diesel fuel depending on which standard is adhered to for the final blend. Low-level biodiesel blends can range from 2 to 5 percent of B100 mixed with the conventional diesel fuel to meet American Society for Testing and Materials (ASTM) specification D975. Higher blends of B100 between the range of 6 and 20 percent by volume must meet ASTM specification D7467.[xcvii] A survey of biodiesel producers in the United States was conducted in 2004 to identify the properties of both B100 and B20.[xcviii]

Production of biodiesel in the United States has dramatically increased over the last couple of years (See Figure 3.39.) in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel that went into effect in 2005.[xcix] Output is expected to continue growing as refiners and other obligated parties strive to meet biodiesel blending requirements mandated by RFS2. (See RFS biodiesel discussion later in chapter.)

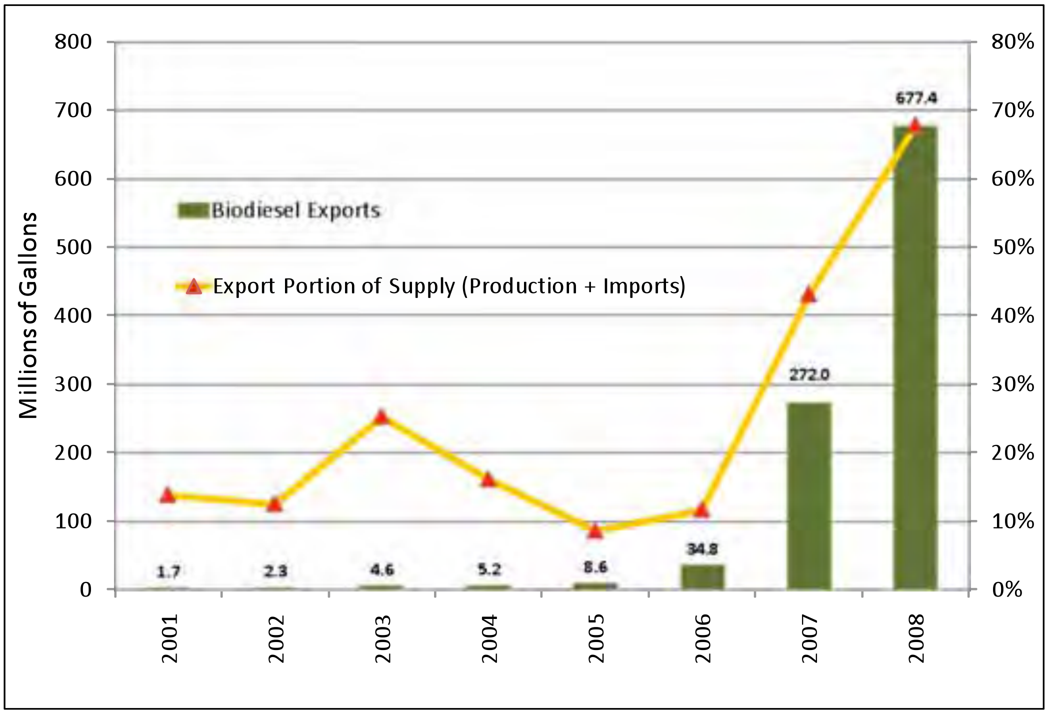
Figure 3.39: U.S. Biodiesel Production 2001-2008



Source: Energy Information Administration (EIA).

Significant quantities of biodiesel have been exported over the last couple of years due to more attractive wholesale prices and U.S. exporters' use of the dollar-per-gallon biodiesel blenders' credit. (See Figure 3.40.) Biodiesel exports have grown from nearly 9 million gallons in 2004 to more than 677 million gallons in 2008. As the chart also indicates, a growing percentage of total U.S. biodiesel supply has been exported, rather than used, in domestic transportation fuels. In 2008 alone, export volumes represented 68 percent of total U.S. biodiesel supplies (production combined with imports).

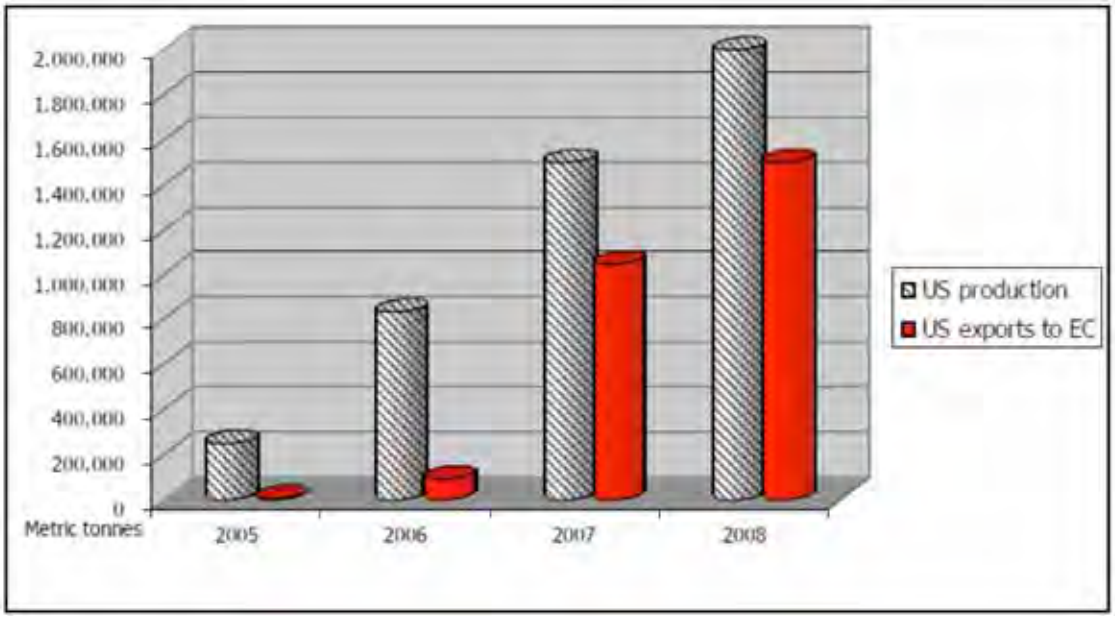
Figure 3.40: U.S. Biodiesel Exports and Percentage of Total Supply 2001-2008



Source: Energy Information Administration (EIA).

According to the European Biodiesel Board, a significant quantity of the U.S. biodiesel production was exported to European Union countries, especially over the last couple of years. (See Figure 3.41.)[c] However, the continuous flow of biodiesel exports to Europe from the United States is not expected to be maintained since the European Union has recently taken action to apply a combination of import duties (both countervailing and anti-dumping) that were approved in July 2009 for a period of five years.[ci] These new tariffs are designed to compensate for the economic advantage gained by United States biodiesel exporters from the dollar-per-gallon blenders' credit.[cii] As a consequence of these actions, United States exports of biodiesel have declined back to 16 percent of supply based on the most recent information available from April 2009.

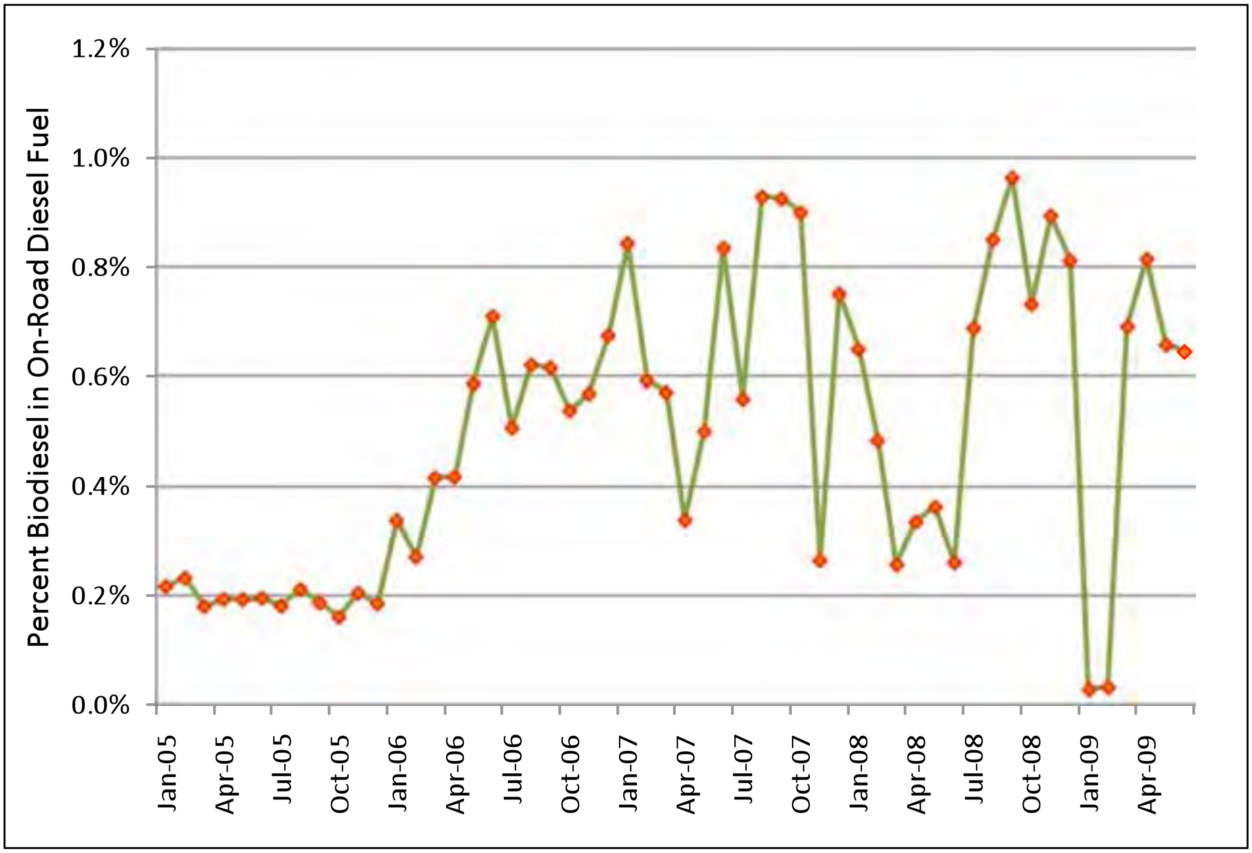
Figure 3.41: U.S. Biodiesel Production and Europe Exports 2005-2008



Source: European Biodiesel Board (EBB) – approximately 300 gallons of biodiesel per metric tonne.

The large exodus of domestic biodiesel production from the United States to Europe has resulted in biodiesel blending levels that have fluctuated between 0.2 and 1.0 percent as illustrated by Figure 3.42. Absent the large increase of biodiesel exports, blending levels in the United States could have increased to an average of 1.29 percent during 2008, rather than the actual 2008 average of 0.61 percent. It is expected that the application of the EU tariffs will result in a decrease of biodiesel exports and an increase of the average biodiesel concentration in the United States. Over the next couple of years, production and use of biodiesel are expected to grow due to higher levels mandated by the RFS2 regulations.

Figure 3.42: U.S. Biodiesel Blending Levels 2005-2009

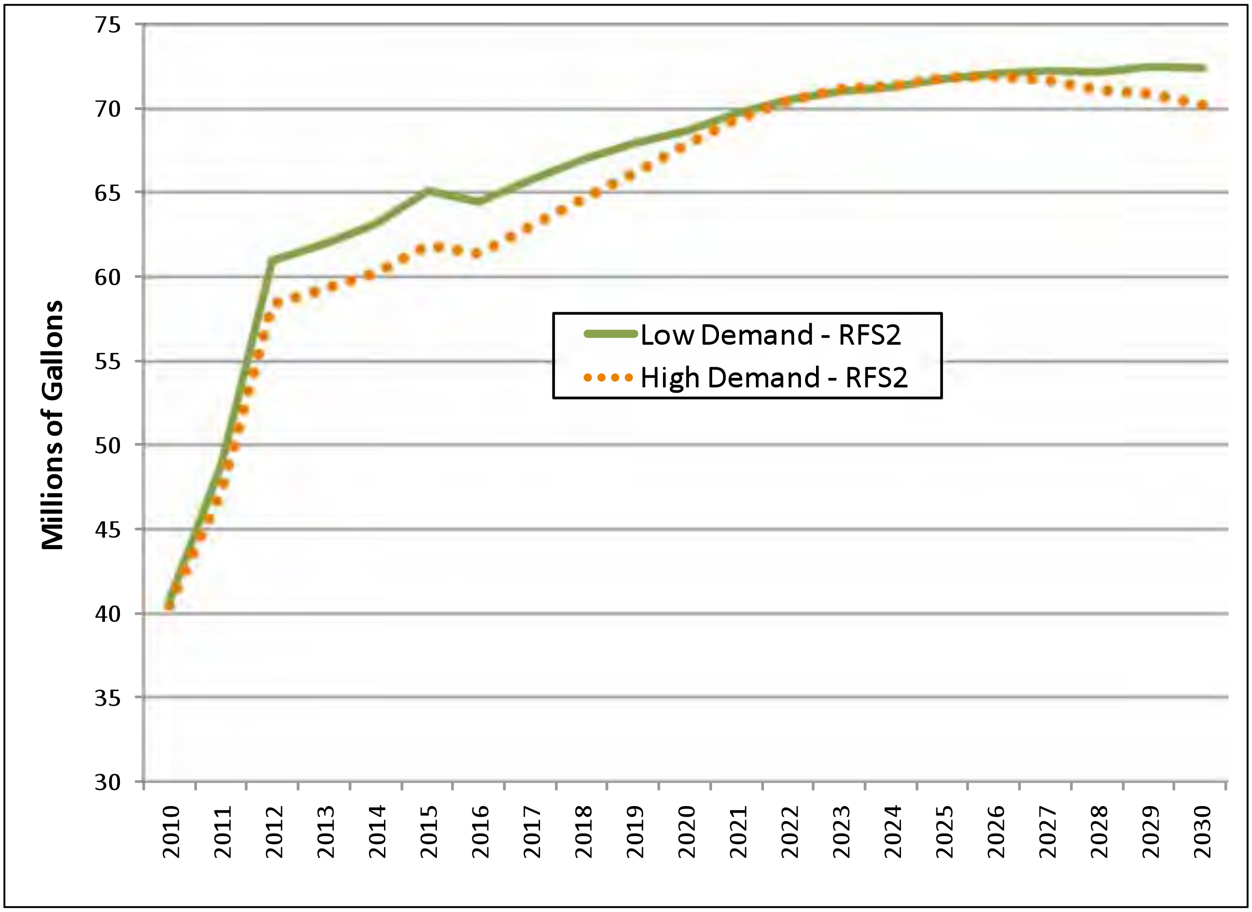


Sources: Energy Information Administration (EIA) and Energy Commission analysis.

Renewable Fuels Standard – Increased Demand for Biodiesel

Earlier in this chapter the RFS2 “fair share” obligations for California were presented for both ethanol and biomass-based diesel fuel. Under the Low Diesel Demand Case, biodiesel “fair share” ranges from 41 million gallons in 2010 to 72 million gallons by 2030. Under the High Diesel Demand Case, biodiesel “fair share” ranges from 41 million gallons in 2010 to 70 million gallons by 2030. (See Figure 3.43.) Based on these projected volumes, California’s average biodiesel blending concentration is not expected to be higher than 1.8 percent. However, California’s LCFS requirements are anticipated to increase the level of biodiesel use to significantly higher levels that have yet to be fully quantified. (See LCFS discussion below.) In particular, if biodiesel demand necessitated by the LCFS approaches 10 percent by volume, biodiesel demand could reach between 435 million gallons by 2020 and 540 million gallons by 2030. Further, B20 levels would infer biodiesel demand levels in California of 870 million gallons by 2020 and 1,080 million gallons by 2030.

Figure 3.43: California Biodiesel RFS Fair Share Obligations 2010-2030



Source: Energy Commission analysis.

Increased Biodiesel Use in Retail Diesel Fuel – B5 to B20

Retail diesel fuel dispensers and USTs are certified to handle diesel fuel that contains biodiesel at concentrations of up to 5 percent by volume. However, these same USTs have not received independent testing organization approvals for biodiesel blends greater than 5 percent (B5) and up to 20 percent (B20). To provide additional time for these approvals to be developed, the California State Water Resources Control Board (SWRCB) issued emergency regulations that took effect on June 1, 2009, that allowed for a 36-month variance from this UST requirement.[ciii] This action has removed a potential barrier to expanded use of biodiesel in California. Assuming biodiesel fuel blends in California do not exceed the B20 level over the foreseeable future, retail station modifications should be negligible to accommodate such increased concentrations. However, for those retail locations that want to dispense B99 or B100, storage of biodiesel at these concentrations in an underground storage tank may not be permissible at this time per the SWRCB. Therefore, retailers still have the option to store B99 or B100 in an aboveground storage tank (AGT). Installation of a new AGT would be significantly more expensive than using an existing UST that is currently used to store and dispense diesel fuel.

Biodiesel Blend Wall

It is likely that the LCFS will necessitate increased use of biodiesel in California beyond the minimum "fair share" volumes calculated for RFS2 compliance. As is the case with ethanol, increasing levels of biodiesel blended with conventional diesel fuel pose some barriers that would need to be addressed to ensure biodiesel could be used at concentrations of up to 20 percent by volume. In addition to the UST issues previously cited, there is a lack of warranty coverage for biodiesel blends in excess of B5. Not all original engine manufacturers allow biodiesel bends in excess of B5. This limitation is also imposed by some companies that provide extended motor vehicle warranties.[civ] Until this warranty issue is covered, retail station operators may be reluctant to offer B20 for sale at all of their dispensers. Therefore, a dedicated UST and retail dispenser may have to be installed for B20 blends.[cv] This scenario could result in significantly higher retail infrastructure costs to achieve widespread biodiesel penetration in California above B5 levels.

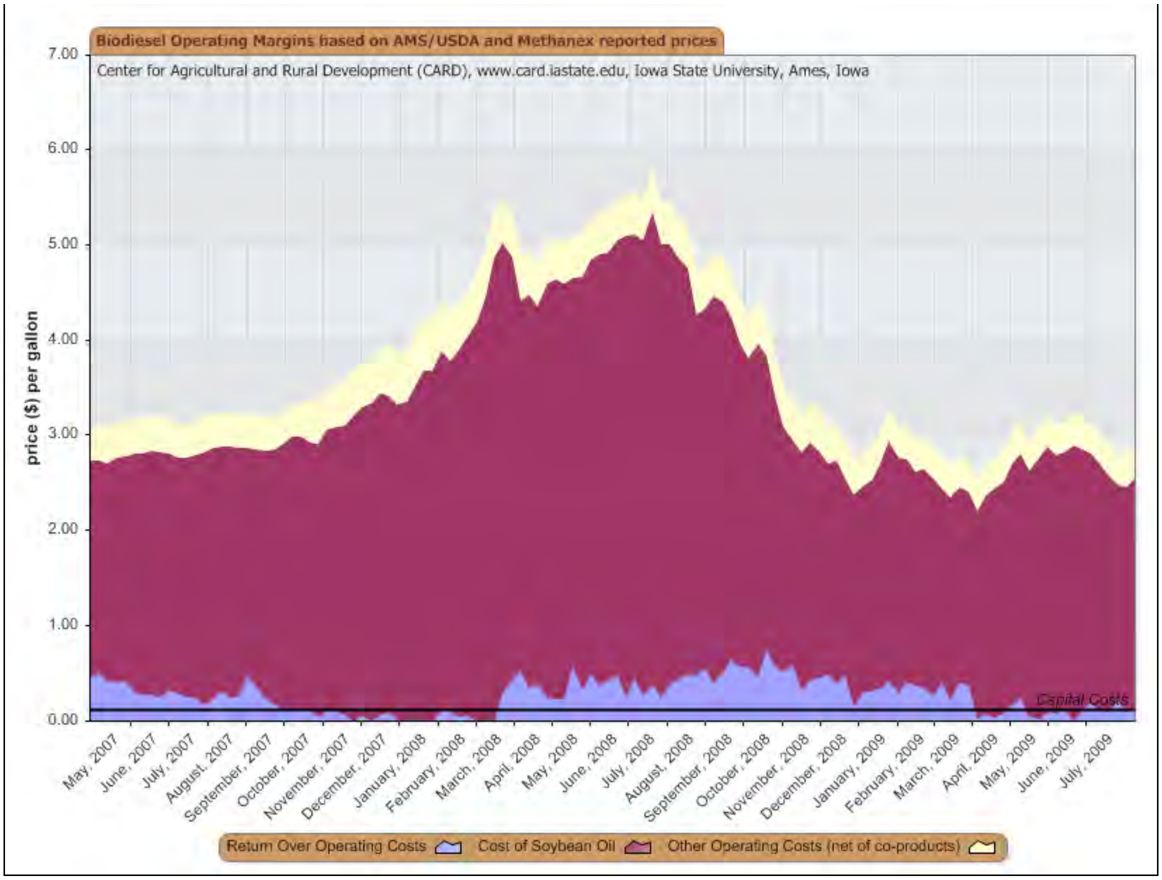
LCFS and Biodiesel

As explained earlier in this chapter, there has been no quantitative analysis performed to determine how the volumes and types of biodiesel used in California could change as a consequence of the LCFS. When additional carbon intensity pathways for various types of biodiesel are published, the Energy Commission will conduct analysis to identify any potential supply or infrastructure issues that could result over the near to mid-term period. Regardless of any future analysis, there is a regulatory disconnect regarding title transfer from obligated parties to distributors such that a refiner would not have any control over what type of low carbon intensity fuel may or may not be added at the truck rack.[cvi] Currently, only two types of biodiesel (and renewable diesel) have direct and indirect carbon pathways published by ARB, waste oil and tallow. Based on the carbon intensities of these fuels, refiners and other obligated parties could fully comply with the per-gallon diesel LCFS requirements in B20 blends of diesel fuel (20 percent biodiesel and 80 percent conventional diesel fuel).[cvii] However, both of these alternative diesel types are quite limited from a supply perspective. Therefore, sole dependence on these alternative diesel fuels for LCFS compliance is extremely unlikely.

U.S. Biodiesel Supply Outlook and Issues

The RFS2 regulations call for a minimum use of 1.0 billion gallons per year of biomass-based diesel fuel by 2012. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating U.S. facilities, along with another 595 million gallons per year of idle production capacity and another 289 million gallons per year capacity under construction.[cviii] It appears as though there may be sufficient domestic sources of biodiesel production facilities to meet the RFS2 requirements for several years. The large number of idle biodiesel facilities is not surprising as the economics for biodiesel producers have deteriorated through most of 2009 as evidenced by the recent trends illustrated in Figure 3.44. As is the case with ethanol, it is anticipated that these poor biodiesel production economics are temporary and will continue to improve as demand for biodiesel grows through the RFS2 mandates and the LCFS necessity to reduce the per-gallon carbon intensity of diesel fuel in California.

Figure 3.44: U.S. Biodiesel Operating Margins May 2007 – July 2009



Source: Center for Agricultural and Rural Development, University of Iowa.

Biodiesel Supply Outlook

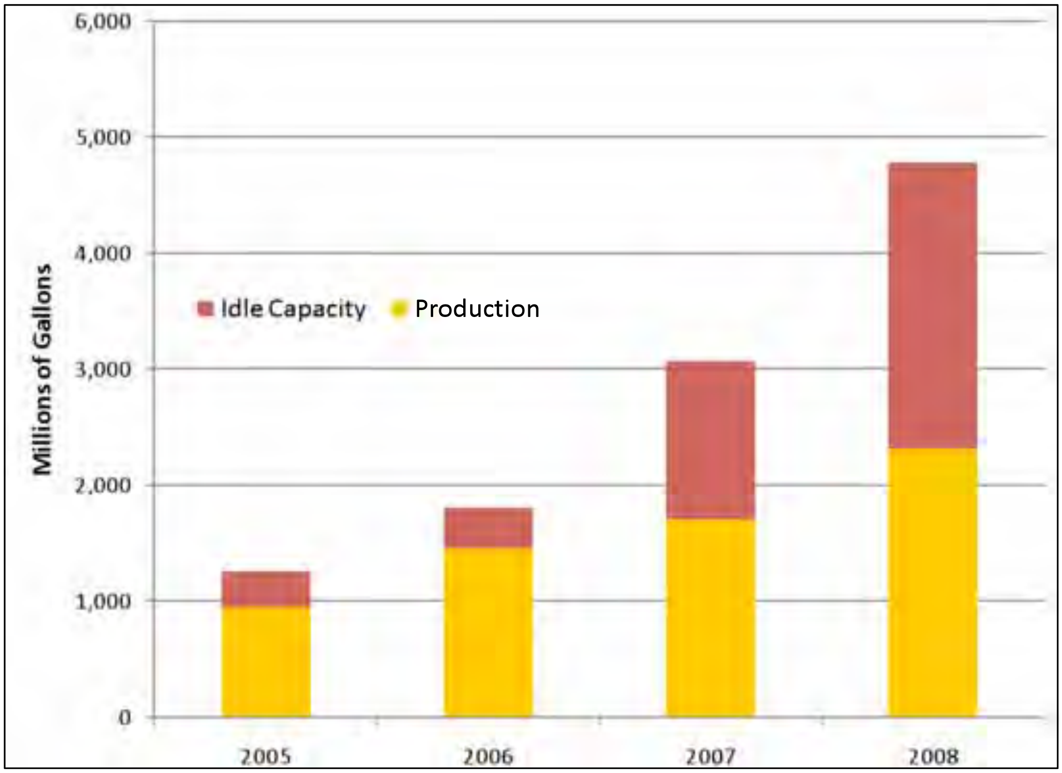
California Biodiesel Supply Outlook and Issues

According to *Biodiesel Magazine*, there are 10 biodiesel production facilities operating in California with an annual production capacity of 63 million gallons, along with 3 idle plants with a combined production capacity of 8 million gallons.[cix] Although these production volumes are insufficient to supply all of California's "fair share" of biodiesel, there should be ample biodiesel production capacity outside the state to provide the necessary balance to meet the High Demand RFS Fair Share Obligation Case for biodiesel use of 68 million gallons by 2020.

Europe Biodiesel Supply Outlook and Issues

Europe continues to be the dominant producer of biodiesel in the world, estimated to possess approximately 68 percent of the global production capacity.[cx] Over the last couple of years, production capacity has increased from 1.26 billion gallons per year in 2005 to 4.79 billion gallons per year in 2008. (See Figure 3.45.) However, a growing percentage of these biodiesel facilities have been idled by poor economics and less expensive imports from the United States. Despite these poor operating conditions, European biodiesel production capacity is estimated to reach 6.25 billion gallons during 2009.[cxi]

Figure 3.45: Europe Biodiesel Production and Idle Capacity 2005-2008



Source: European Biodiesel Board (EBB).

California Biodiesel Logistics Outlook and Issues

Infrastructure requirements for biodiesel are similar to those of ethanol in that biodiesel needs to be transported from points of production (both inside and outside California) to initial redistribution hubs via rail and marine vessels. Once inside California, the biodiesel would then need to be hauled to distribution terminals that dispense diesel fuel destined for truck stops and other retail locations. Although similar in need, the biodiesel infrastructure has not been developed to the same extent as that of ethanol primarily because there has not been any meaningful increase in the use of biodiesel to date. It is likely that changing circumstances could require a sizable increase in the use of biodiesel and a commensurate development of the associated distribution infrastructure to ensure adequacy of diesel fuel supplies for California. Currently, the biodiesel infrastructure is inadequate to accommodate widespread blending of biodiesel even at concentrations as low as B5. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use.

Biodiesel Distribution Terminal Logistics

Biodiesel is blended with diesel fuel as the tanker truck is loaded before delivery to the retail station. As such, the biodiesel (B100) must be stored in segregated tanks. Unlike ethanol, only a few distribution terminals have biodiesel storage capabilities due to significantly lower demand levels when compared to ethanol. This circumstance appears to be the most significant barrier to near-term increased use of biodiesel. To help ensure adequacy of biodiesel distribution capability for meeting increased demand levels associated with the federal RFS2 and the state's LCFS, construction of biodiesel storage tanks at a minimum of 50 percent of California's distribution terminals by 2012 would likely be necessary. Costs for such an undertaking could amount to between $25 million and $50 million. At this time, biodiesel use is discretionary and at very low concentrations (on average). That situation is expected to change as refiners and other marketers in California move to comply with both the RFS2-mandated biodiesel blending requirements and the additional volumes that will surely be necessary to reduce the per-gallon carbon intensity of diesel fuel per the LCFS.

Distribution terminal modifications will need to be made over the near to mid-term to help ensure sufficient volumes of biodiesel will be available for blending with conventional diesel fuel. New storage tanks will need to be constructed in most cases, although in some situations an existing storage tank can be converted from one type of fuel to biodiesel at a significantly lower cost and time frame. However, this approach would not be viable for most distribution terminals since all or most of the existing storage tanks are already being continuously used. If a terminal operator needs to install a new storage tank, the process to obtain a permit can be lengthy (as long as 12 to 18 months).

Biodiesel Rail Logistics

The majority of biodiesel use in California is believed to originate from production facilities located within the state. Approximately 50 million gallons of biodiesel was used as transportation fuel during 2008, slightly less than the operating biodiesel production capacity of more than 60 million gallons per year. Over the next several years, biodiesel volumes are expected to increase. It is possible that biodiesel demand levels could exceed 10 or even 20 percent of total diesel fuel used in the transportation sector. If so, demand volumes could easily surpass 400 million to 800 million gallons per year by 2022.[cxii] Assuming sufficient spare production capacity throughout the United States to meet this potential increase in California biodiesel demand, it is likely that most of the incremental biodiesel will originate from facilities located outside the state. This means that imports of biodiesel may be necessary via rail and/or marine vessel. Currently, there are no biodiesel rail facilities designed to handle unit trains. Ultimately, biodiesel unit train receipt capability may not be necessary due to demand levels that may be too low to justify the expense. It is more probable that rail receipts of biodiesel will be transferred to tanker trucks via transloading, as is the case with the Kinder Morgan ethanol transloading project in Northern California. In fact, staff believes that there is already a modest amount of biodiesel transloading occurring in California, a practice that is expected to grow over the next several years.

Biodiesel Marine Logistics

Periodically, biodiesel has been imported into California by marine vessels. Due to cargo sizes that are smaller than ethanol, the storage tank requirements to unload the biodiesel are more modest. Optimal storage tank sizes are less than 10 thousand to 50 thousand barrels in size. Smaller storage tanks at marine terminals are normally reserved for lubricants, specialty solvents, and other chemicals that have limited demand volumes. Based on conversations with various biodiesel importers, these types of storage tank accommodations at marine import facilities are limited. In fact, a marine terminal in Southern California that was recently closed had been used periodically for importation of biodiesel. Availability of marine facilities is limited and would need to be made available if meaningful volumes of biodiesel were to be imported via marine vessel. However, as was previously discussed, there is sufficient domestic biodiesel production capacity to supply California's anticipated needs over the near to mid-term that could reasonably be delivered in rail cars, rather than marine vessels.

Biodiesel Truck Logistics

As is the case with ethanol logistics, few distribution terminals have the ability to receive shipments via rail. Therefore, most or all of the biodiesel would first need to be delivered to distribution terminals via tanker trucks to segregated storage tanks. Since the volume and associated trucking requirements are less than that of ethanol, incremental trucking requirements should not be as pressing. For example, assuming an incremental 300 million gallons per year of biodiesel was being transported to California distribution terminals, approximately 50 additional tanker trucks may be necessary (assuming two trips per truck per day). Although the additional trucking requirements may be modest, most distribution terminals would need to be modified so that the biodiesel could be received and transferred to segregated storage tanks at the terminals (a capability that all of the terminals have for ethanol today). This ultimate capability will require both time and an unquantified capital expense to complete.

Biodiesel Pipeline Logistics

As biodiesel use continues to grow in the United States, so too do strategies for reducing the transportation costs of biodiesel. By far, pipeline delivery costs are the lowest of any of the primary methods of delivery, usually one tenth (1/10) of the cost compared to tanker truck delivery.[cxiii] Pipeline distribution companies have recently initiated shipments of biodiesel blends in portions of certain pipeline networks. One such example is the recent distribution of diesel fuel containing up to 5 percent by volume biodiesel (B5) in portions of Kinder Morgan's Plantation Pipeline located in the Southeastern United States.[cxiv] However, there are operational restrictions that limit this practice. The primary concern of transporting biodiesel blends in mixed petroleum product pipeline systems is the potential contamination with jet fuel. At present, Kinder Morgan is restricting biodiesel blend shipments to portions of their pipeline system that do not handle any jet fuel. Since all of the Kinder Morgan petroleum product pipeline systems in California are used to ship jet fuel, it is unlikely that this practice could be adopted for use in this state. Over time, if the potential concern of jet fuel contamination with biodiesel can be overcome, the primary logistical impact would be the reduced needs for delivery of biodiesel to distribution terminals via tanker trucks.

Transportation Natural Gas

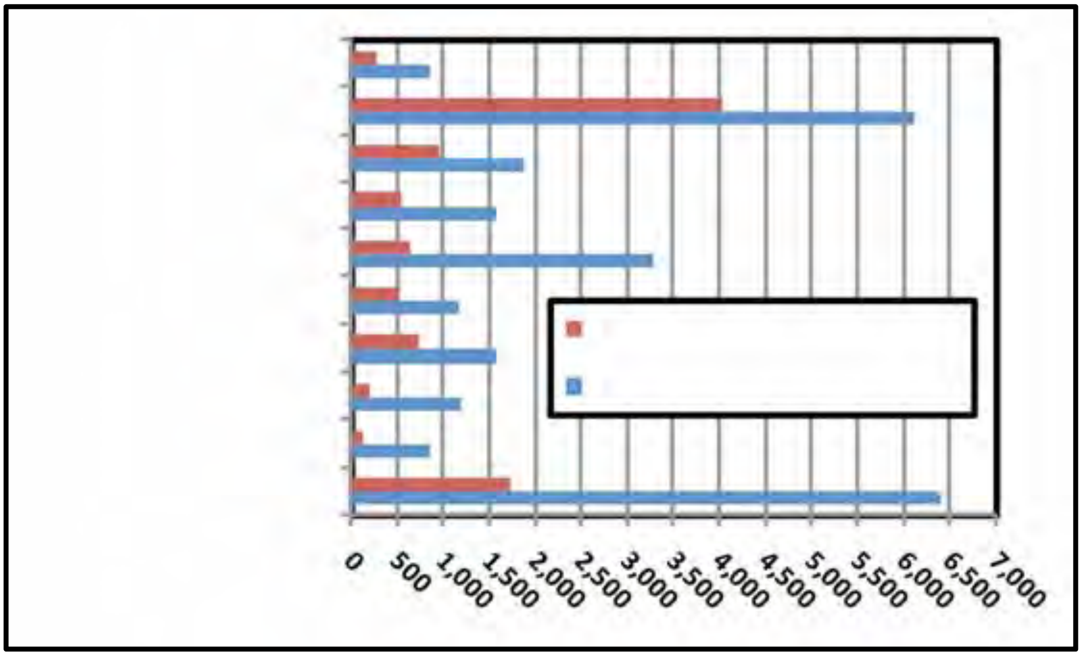
Natural gas has been an established vehicle fuel in California for more than 20 years. This fuel accounts for approximately 25 percent of the total energy used for all purposes in the United States and 87 percent of the natural gas used is domestically produced in the United States.[cxv] Traditionally, natural gas is less expensive than gasoline and diesel on an energy basis and is provided as a transportation fuel in one of two forms: CNG or LNG. CNG is simply natural gas compressed to pressures above 3,100 pounds per square inch (psi). LNG is liquefied by cooling the natural gas to temperatures below -260°F at normal pressure.

Natural gas vehicles have many environmentally friendly attributes including: emitting 60 to 90 percent fewer smog-producing pollutants and 30 to 40 percent fewer GHG emissions[cxvi] than gasoline and diesel-powered engines for light duty vehicles. Currently, ARB is placing a proposed 75.2 to 75.6 carbon intensity value (gCO_2e/MJ)[cxvii] on CNG delivered via pipeline. The environmental profile of natural gas can be further improved through advancements in biomethane or biogas, which are renewable sources for the production of natural gas. This production method of creating natural gas and converting it to CNG has been estimated to have a 12.5 carbon intensity value (gCO_2e / MJ) by ARB, which is less than 1 / 6th of the current value for conventional fossil fuel natural gas sourced from North America and 87 percent less than gasoline GHG emissions.

Natural Gas Vehicles

In 2008, there were 24,810 light-duty CNG vehicles[cxviii] registered and operating in California with less than half of these vehicles (10,747) as being registered to individual owners. (See Figure 3.46.) This represents a significant increase over 2000 totals of 3,082; however, the light-duty natural gas vehicle population has been relatively flat since 2001. State and local governments accounted for 31 percent of the ownership of light-duty CNG vehicles with 78 percent of those vehicles existing in government vehicle fleets of 1,000 vehicles or more. In addition to light-duty vehicles, there were an additional 9,674 medium- and heavy-duty natural gas vehicles registered in California in 2008, with 7,144 of those vehicles being buses, most of them CNG-powered. The remaining medium- and heavy-duty vehicle population is spread across various vehicle types with the greatest number of them being garbage trucks (1,003). These counts represent significant increases in natural gas vehicles over the total of 3,640 for all natural gas-powered vehicles registered in 2000.

Figure 3.46: Natural Gas Vehicle Counts by Specific Counties, October 2008



Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 500 light duty natural gas vehicles

Several different vehicle manufacturers have produced light-duty CNG vehicles, but currently only the Honda GX CNG is offered for sale in the United States[cxix]. The lack of vehicle offerings was identified as one of the primary hurdles to natural gas becoming a major publicly used transportation fuel in California[cxx]. Another barrier is that light-duty CNG vehicles often require more frequent refueling due to having approximately 25 percent less range than gasoline or diesel vehicles per one tank of fuel. And like electric vehicles, natural gas vehicles are so unfamiliar to most consumers that they are unable to generate favorable impressions among many potential car buyers.

Natural Gas Refueling

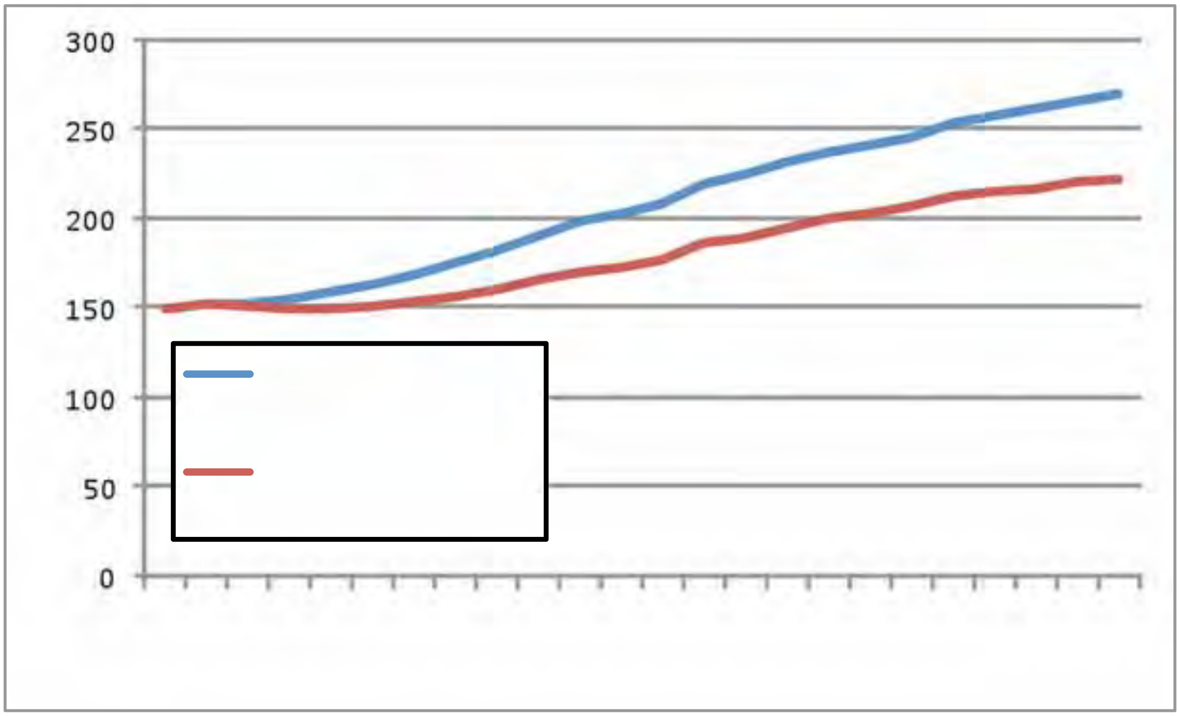
Southern California Gas Company lists 90 publicly accessible natural gas refueling stations[cxxi] in Southern California, as well as around 200 private stations. An additional eight stations are identified by Clean Energy in the Northern / Central California region. Refueling options could be further increased through the use of a home refueling appliance (HRA)[cxxii], which could be used to refuel a CNG vehicle tank at an owner's home. This refueling process takes on average anywhere between 5 to 8 hours to fill 50 miles worth of natural gas and requires the owner to have access to a natural gas line. Installation of these devices is reported to be easy but they do require professional installation.[cxxiii] This could represent a significant advantage for natural gas vehicles in commuter settings since the owner of such a unit could eliminate refueling at public stations from normal weekly activities.

California Transportation Natural Gas Demand Forecast

California's use of natural gas in the transportation sector is forecasted to increase substantially. As measured in therms, the forecast shows demand rising from 150.1 million therms in 2007 to 270.3 million therms by 2030 under the High Petroleum Price Case (High Natural Gas Demand

Case) and 222.9 million therms by 2030 under the Low Petroleum Price Case (Low Natural Gas Demand Case). (See Figure 3.47.) The number of compressed natural gas (CNG) vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030.

Figure 3.47: California Transportation Natural Gas Demand Forecast



Source: Energy Commission analysis

Strategies for Increased Adoption

Several factors were identified at an Energy Commission workshop that would potentially promote the use of natural gas as a transportation fuel.[cxxiv] Foremost is to increase light-duty OEM natural gas vehicle offerings. A successful strategy for siting of refueling facilities has been to target high-volume customers such as taxi fleets and heavy trucks. But replicating this success in the general public requires simultaneously developing refueling infrastructure that is targeted to emerging geographic clusters of vehicle purchasers. The new infrastructure needs to find investment money and policy incentives that encourage that investment, although several companies are executing business models that are expanding the infrastructure. The price of fuel can be very attractive to high-volume purchasers, but vehicle cost can be a barrier to more light-, medium-, and heavy-duty vehicle purchases unless alleviated by declining production costs, driven by on-board fuel storage needs or consumer incentives. The *State Alternative Fuels Plan – AB 1007 Report* also identified several actions that would encourage the development of the industry:

- Develop new utility rate structures for HRAs.
- Stimulate the development of biomethane/biogas for use in natural gas vehicles and as a feedstock for hydrogen.
- Improve on-board storage technology to improve the range and costs of natural gas vehicles; develop natural gas hybrid electric technology.
- Use the GHG emission benefit credits in investment and business operation plans.

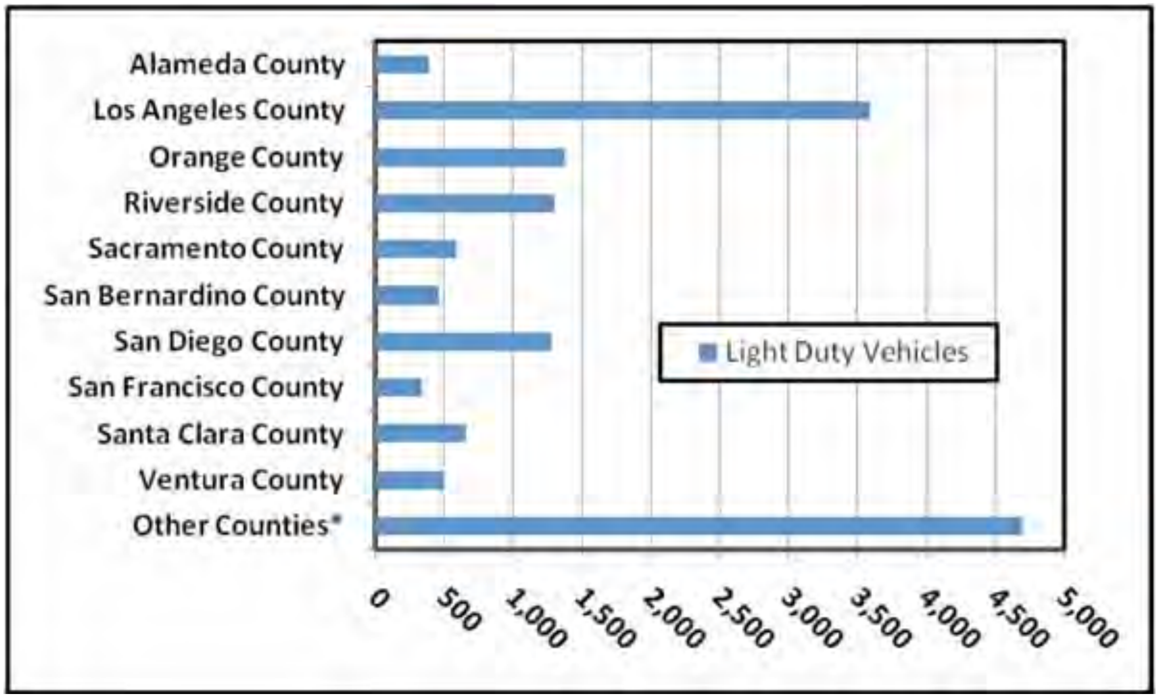
Transportation Electricity

FEVs and PHEVs have numerous benefits that make them attractive in addressing carbon reduction and petroleum dependence in the transportation sector. If the electricity used to recharge them comes from renewable or natural gas sources, they have the potential to significantly reduce GHG emissions compared to conventional petroleum-fueled vehicles. ARB places a total carbon intensity value (gCO_2e / MJ)[cxxv]of 34.9 to 41.4 on the use of this fuel type depending on the mix of renewable fuels used in the production of the electricity. These values are adjusted to reflect the increased motor efficiency that electric vehicles exhibit and should be compared to the CaRFG-CARBOB value of 96.1 to determine full GHG reductions. These lower values in relation to gasoline are estimated by ARB to reduce vehicle emissions anywhere from 9 to 35 percent, depending on the proposed scenarios.[cxxvi] Use of substantial numbers of these vehicles would also provide air quality benefits by reducing criteria pollutant emissions compared to conventional vehicles. The cost of electricity, especially if utilities offer off-peak rates and separate meters for vehicle recharging, would be well below the cost of gasoline or diesel when factoring in engine efficiency.

Full Electric and Plug-In Hybrid Electric Vehicles

According to DMV data, there were 14,670 FEVs operating in California in 2008. While a substantial increase over the 2,905 operating in 2001, it is substantially less than the 23,399 operating in 2003. Since 2004 this population has remained relatively flat. Primarily, these are neighborhood electric vehicles and subcompacts. What is the range of forecasts for their adoption? According to Southern California Edison, the utility is expecting between 400,000 and 1.6 million electric vehicles by 2020.[cxxvii] Plug in hybrid electric vehicles (PHEVs) combine the benefits of electric vehicles (that can be plugged in) and hybrid electric vehicles (that have an engine) and are scheduled for mass production as early as 2011. The Energy Commission forecasts the number of FEVs and PHEVs to reach nearly 3 million by 2030. Figure 3.48 shows the number of FEVs operating in California in October 2008 by a selected set of counties.

Figure 3.48: Full Electric Vehicle Counts by Specific Counties, October 2008

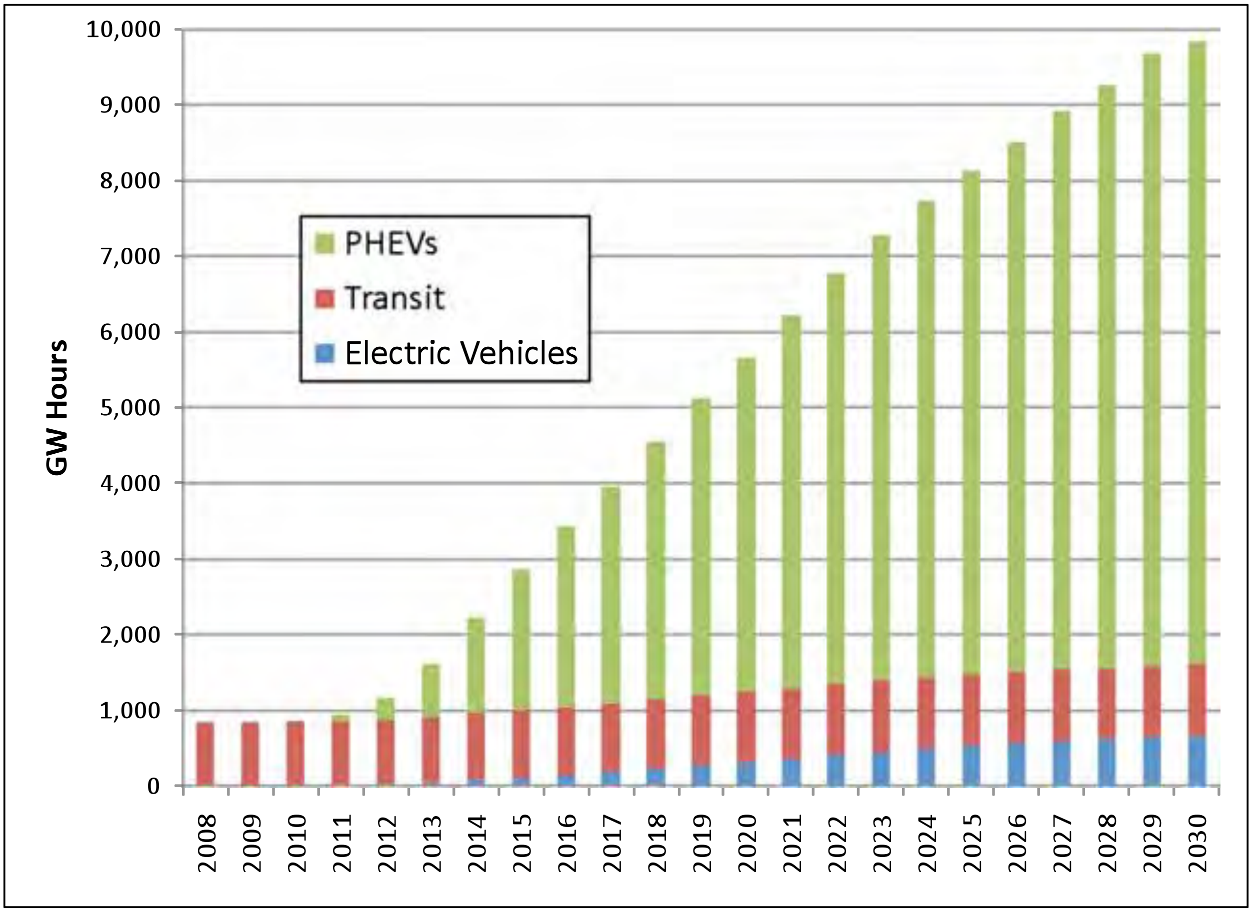


Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 300 electric vehicles.

California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of PHEVs. As measured in gigawatt-hours (GWhs), demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. As Figure 3.49 illustrates, the surge in transportation electricity use under the High Petroleum Price Case (High Electricity Demand Case) is mainly from PHEVs and to a lesser extent full electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

Figure 3.49: California Transportation Electricity – High Demand Forecast



Source: Energy Commission analysis.

Despite their technical potential, air quality benefits, and the enthusiasm of a cadre of early adopters, electric vehicles have not been particularly successful in penetrating transportation markets. Barriers to wider-spread purchase of FEVs and PHEVs include the lack of commercially available models and delays in delivery, their higher price, and concerns about their size and range.[cxxviii] According to the 2008 CVS, relatively negative perceptions are held by many potential car buyers of FEVs, while PHEVs are viewed much more favorably. These perceptions of FEVs by potential vehicle purchasers may be intensified by a lack of familiarity with the technology and uncertainties over how the vehicles would be recharged or the expense of replacing batteries. Moreover, the infrastructure to support these vehicles is still undeveloped, and the future course of development of this support is not readily apparent to consumers. At the same time, survey respondents' willingness to consider purchasing PHEVs show that, with backup conventional internal combustion technology available in a vehicle, consumers recognize the economic and environmental benefits of using electricity for fuel. Consumer education will need to improve to address this lack of familiarity with electric vehicle technology.[cxxix]

Transportation Electricity Infrastructure

Several infrastructural barriers will need to be overcome to stimulate greater penetration of electric vehicles. Utilities will have to develop procedures, standardized equipment, and rates that are conducive to the needs of vehicle users. Initially, this should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were conducive, as recharging can easily be accomplished mostly off-peak. Consumers could be further motivated if they were able to receive the carbon credits that accrued to their use of this energy source.[cxxx]

As the vehicle population grows, the recharging system can expand to workplace and public recharging stations. Previous emphasis may have been too strongly placed on public stations[cxxxi]. Compatible and consistent standards will need to be developed for recharging connectors and other equipment, including 120/240 volt compatibility and “smart” chargers that are designed to efficiently recharge batteries. Expertise and training in the installation and servicing of recharging infrastructure should be more generally available, instead of only limited to a few specialized technicians connected with electric vehicle dealers.[cxxxii]

Per the EIA,[cxxxiii]currently there are two battery technologies that are used in the propulsion of electric vehicles: nickel metal hydride (NiMH) and lithium-ion (Li-Ion). NiMH batteries are currently the more established technology with cheaper costs for production and established safety record but have limited size, which limits the energy potential of this power storage method. In contrast, Li-Ion batteries have the potential to store greater amounts of energy in a lighter storage package, which increases the energy storage-to-weight ratio. Yet, costs for Li-Ion batteries to be used in electric vehicles are estimated to be as much as $30,000 for batteries that would propel a vehicle 100 miles.[cxxxiv] The EIA also identifies lifespan, charge cycling, and safety as additional issues that Li-Ion technology must face to improve its viability. Recharging times for these batteries depend highly on the voltage of the outlet that the vehicle is being plugged into. Recharging the battery can take typically 6 to 8 hours for 110-volt charging and roughly 2 hours for 240-volt charging. Public electric vehicle station could be equipped to handle 480-volt chargers, which would lower the battery recharging time to as low as about 10 minutes but are not currently accommodated by the standard SAE J1772 connector.[cxxxv]

With the industry identifying Li-Ion batteries as the better technology for battery production, possible supply issues with lithium could appear. Current lithium reserves have been estimated at just under 84 million pounds, or 38,000 metric tons, in the United States. Another 410,000 tons of lithium does exist in the United States but is currently economically unfeasible to obtain. It is reported in ARB’s *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1* that this could supply batteries for a total of “2.8 million to 16.8 million vehicles.” Using world reserves, a total of approximately 273 million vehicles could be created.

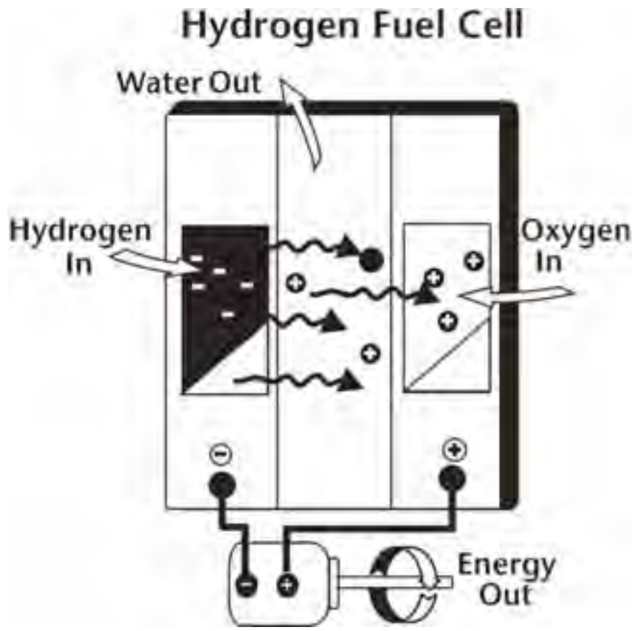
Currently, the EIA states that gas prices must be around $6 a gallon to offset the incremental costs of PHEV technology. On the positive side, the EIA in its *2009 Annual Energy Outlook* forecasts that the cost of these batteries is expected to decline by half by 2020 and again by 2030.[cxxxvi]

The effects on the electric system from expanded use of electric vehicles are also unknown and must be studied more thoroughly. While beyond the scope of this report, several questions must be answered, among them: Will large-scale adoption of electric vehicles stress the electricity production or transmission systems, especially if this adoption is focused in relatively small areas geographically? Will consumers charge off-peak? What will be the sources of the additional electricity needed for electric vehicles, and will the reliance on those sources advance air quality, carbon reduction, and energy system reliability goals?

Hydrogen Fuel Cell Vehicles

There are 400 to 500 hydrogen-powered vehicles in the United States,[cxxxvii] with about 190 of them on the road in California[cxxxviii]. These vehicles use stored hydrogen, which is combined with oxygen (from the atmosphere) through an electrochemical reaction to produce electricity, which is then used to power an electric motor. (See Figure 3.50.)

Figure 3.50: Diagram on the Operation of a Hydrogen Fuel Cell



Source: http://www.eia.doe.gov/kids/energyfacts/sources/IntermediateHydrogen.html

This technology is still relatively expensive due to high production costs of both fuel cells and the hydrogen, yet it is seen as an attractive technology due to its clean emissions capabilities. Currently, hydrogen storage tanks come in 350 or 700 bar variety, which relates to the storage pressure of the tank, 5 million or 10 million psi, respectively. Higher pressure tanks (15,000 psi / 1050 bar) are in experimental stages. Equipped with 10,000 psi / 700 bar tanks, fuel cell vehicles today can reach ranges of 200-350 miles with one fill.[cxxxix]

Natural gas is currently the primary feedstock needed for manufacturing hydrogen, but electrolysis of water can also be used, which has the potential of reducing harmful emissions from this technology to near zero levels. However, this depends on the generation of the electricity used for the process. Renewable power (for example, solar) has the greatest potential to reduce the emissions to near zero. Hydrogen can also be created from renewable feedstocks such as biogas (biomethane), for instance from landfills or livestock farms, to further improve its environmental profile. ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1* estimates a carbon intensity value (gCO_2e / MJ) of 33 to 62 based on various reforming processes, and these numbers should be compared to the CaRFG-CARBOB value of 96.1 to determine full GHG reductions. While hydrogen is the most plentiful gas in the universe, it is found at ground levels in only compound forms with other elements. Because hydrogen is lighter than air, it rises into the atmosphere; thus some manufacturing process must occur to create this fuel in its elementary form.

Standards and Infrastructure

While hydrogen has many advantageous emissions qualities, hydrogen currently has no fuel quality or measurement standards for consumption and sale.[cxl] National and in-state standards need to be developed for device specifications, testing and certification methods, sampling techniques, method of sale, dispensing, and unit of measuring. Safety standards are mostly addressed in the permitting process by fire regulations.[cxli]

Currently existing hydrogen stations cannot sell hydrogen at their pumps. This is due to the lack of metering systems and dispensing rules approved by California Department of Food Agriculture's (CDFA) Division of Measurement Standards (DMS) for this purpose. Given this deficiency, California is set to be the leader in establishing hydrogen fuel standards. CDFA / DMS is working with the Society of Automotive Engineers (SAE), ASTM, and the International Organization for Standardization (ISO) to develop these specifications. The Energy Commission is also set to address this problem with CDFA in an upcoming interagency agreement. This agreement will be handled through the Energy Commission's Emerging Fuels and Technologies Office and is being designed to specifically solve the measurement and quality standard problem.

An additional concern is that hydrogen powered vehicles require fuel of a very high purity, which increases the cost of both the fuel and the equipment needed to produce it. For vehicle characteristics testing, NREL in Colorado is using hydrogen fuel at a purity level of 99.99 percent. Despite these hurdles and the dearth of actual vehicles, California still leads the nation in hydrogen refueling sites, with 29 of the total 62 U.S. fueling stations being in California. However, a limited number of those are currently operating and accessible to the public.

Challenges and Strategies

On the vehicle production side, Michael Coates has noted Daimler AG's commitment to the development of advanced vehicle technologies, including hybridization, battery electric, and fuel cell vehicles.[cxlii] Currently Daimler has 100 hydrogen-powered vehicles operating in the world: 61 light-duty fuel cell vehicles, 36 Citaro buses, and 3 Sprinter vans. His testimony also indicates that the primary challenges faced by the industry include a lack of infrastructure in both fuel production and refueling, the need to develop technologies to reduce battery costs, and testing and acceptance of the vehicles by consumers. He emphasized the need for refueling infrastructure to be there when the vehicles arrive and that the stations should be focused in targeted market areas, the west sides of Los Angeles and Orange Counties being specifically mentioned. Moreover, these refueling sites must meet consumer expectations for access, convenience, and fuel quality assurance. Estimated capital costs for the construction of a refueling station range from $1 million to $5 million, depending on whether on-site reforming is considered desirable.

CHAPTER 4: California Crude Oil Imports Forecast

Overview

California's 20 refineries processed more than 1.8 million barrels a day of crude oil in 2008. These facilities are the primary source of transportation fuels for California, Nevada, and Arizona. Over the next several years, the amount of crude oil required in California could remain relatively steady, although the sources of crude oil are expected to continue shifting as California's production continues to decline. However, the continual trend of increasing quantities of crude oil imports could be altered by a resumption of offshore exploration and production in California state and federal OCS waters or a cessation of California refinery expansion. The likelihood that either of these occurrences will alter the trajectory of crude oil imports over the near to mid-term period is debatable, since both would require several years of sustained effort to realize tangible results. However, over the longer term, the potential impact on crude oil imports of these two scenarios can be more significant and is presented later in this chapter for comparison.

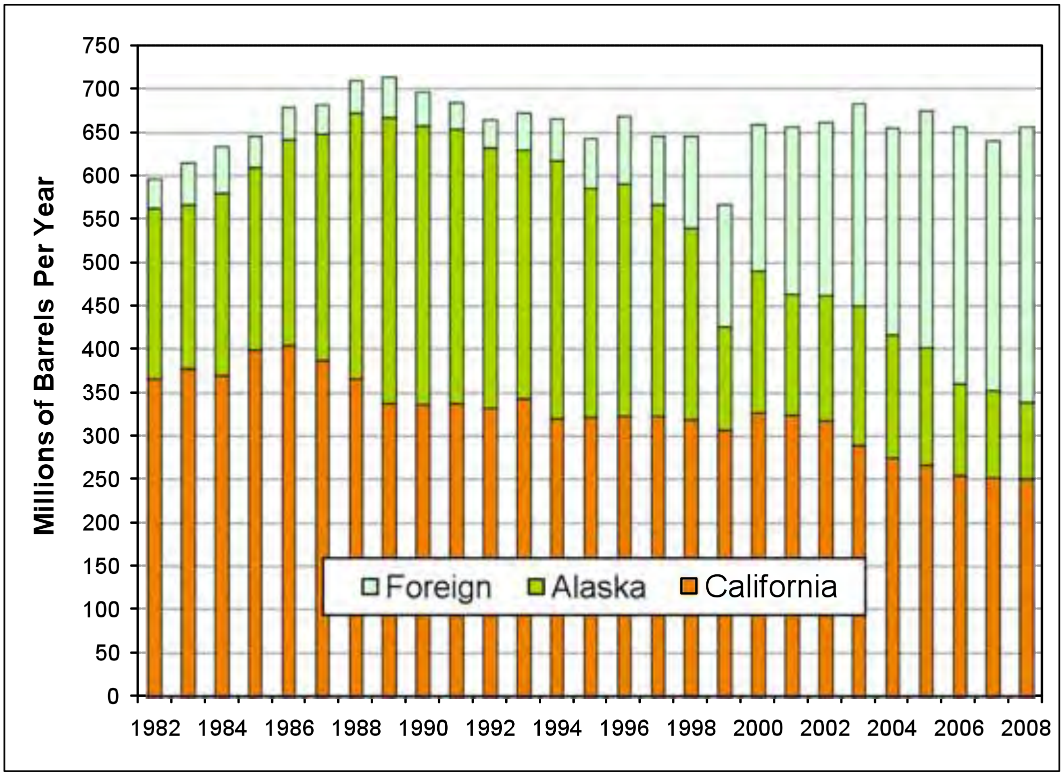
Two factors primarily determine the quantity of crude oil imported into California: the declining production from California crude oil fields and the gradual expansion of refining capacity in the state. Staff developed the forecast of crude oil imports for the state by analyzing trends for both of these factors over approximately the last decade and by making some assumptions going forward over the forecast period. Rather than working toward a single forecast, staff took the approach that a forecasted range of crude oil imports would be more useful in providing a reasonable boundary of incremental crude oil imports. This approach yielded a Low and High Case for crude oil imports.

The lower end of the forecast assumes that the decline rate of California crude oil production is less steep than the average rate of depletion experienced over the last decade. In addition, the gradual growth of California refinery capacity to process crude oil, referred to as refinery creep, is assumed to remain unchanged or flat over the forecast period. These two projections combine to yield a forecast for crude oil imports that is at the lower end of the spectrum. To develop a High Case crude oil import forecast, staff assumed that the depletion of California crude oil sources would continue at a higher rate and that the increase of refinery distillation capacity is assumed to grow at a slower rate than that observed over the last several years.

California Crude Oil Production and Import Sources

California refineries processed 656 million barrels (1.8 million barrels per day) of crude oil in 2008. The majority of this crude oil was obtained from foreign sources (48.5 percent), followed by California sources (38.1 percent), with the balance from Alaska (13.4 percent). Figure 4.1 illustrates the various sources of crude oil used in California refineries since 1982.

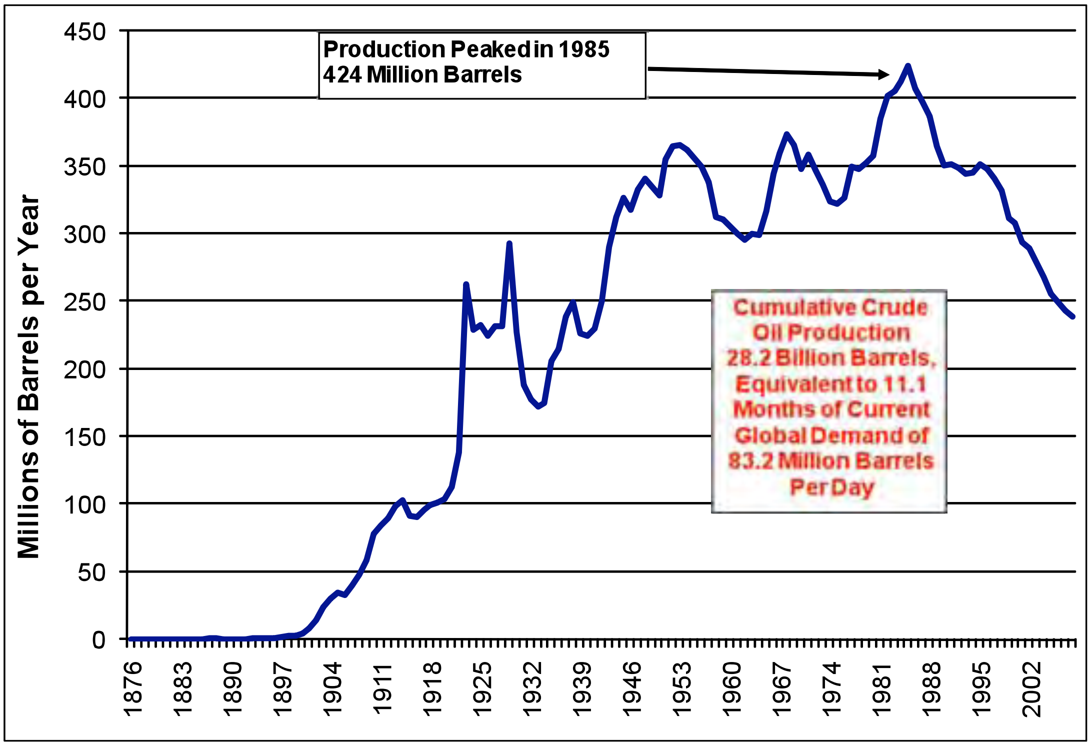
Figure 4.1: Crude Oil Supply Sources for California Refineries



Source: Annual crude oil supply data from the Petroleum Industry Information Reporting Act database

Figure 4.1 also shows that foreign-sourced crude oil is increasing to displace declining quantities of California and Alaska crude oil sources. The top five sources of foreign crude oil imports during 2008 were Saudi Arabia, Iraq, Ecuador, Brazil, and Columbia. A complete list of all countries and associated volumes from 2000 through 2008 is located in Appendix Table C.1. The decline of California crude oil production has continued since 1985, when crude oil production peaked at 424 million barrels per year. California crude oil production began in the early 1860s with “production” obtained from horizontal shafts dug into the sides of hills that contained oil seeps. The first oil producing well was drilled in Humboldt County near Petrolia. Since then, technological advances in crude oil exploration and production have enabled companies to obtain crude oil from deeper reservoirs and extract nearly tar-like oil using thermally enhanced oil recovery (steam injection). Most of California’s crude oil producing fields are mature, such as those in Kern County, and have been producing oil for more than 100 years. Over time, the drilling and extraction of crude oil results in diminishing output from wells. As Figure 4.2 illustrates, the production of California crude oil has peaked and will continue to decline over the foreseeable future. The primary question is: At what rate will California’s crude oil production decline over the next 20 years?

Figure 4.2: California Oil Production (1876 to 2008)

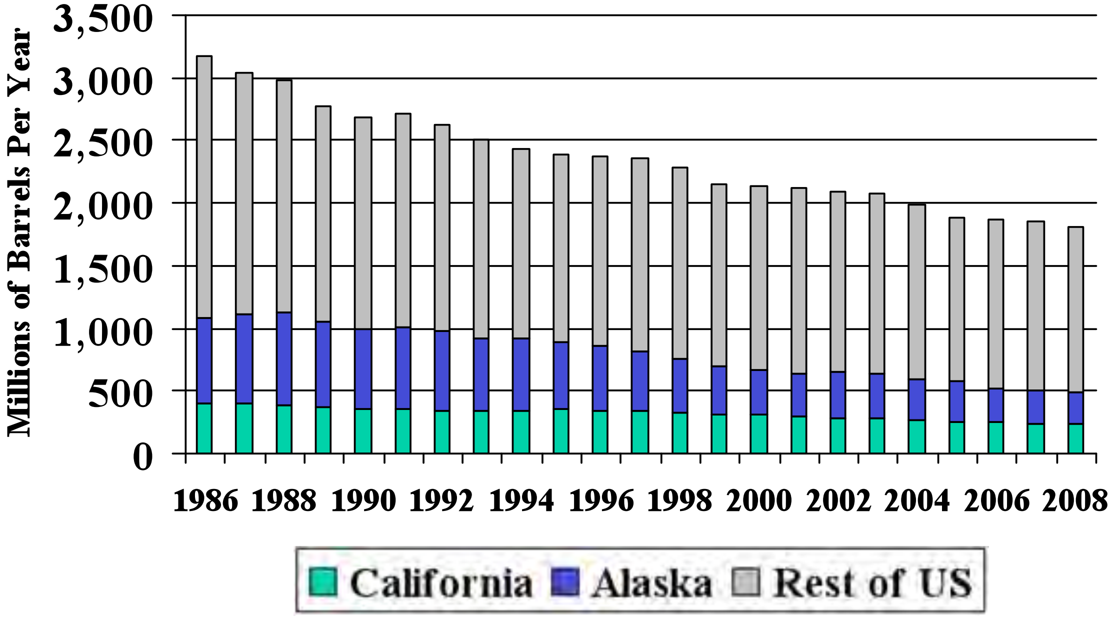


Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission

U.S. Crude Oil Production Trends

Since the late 1980s, crude oil production for both the United States and California has been declining at a steady pace. Since 1986, California crude oil production has declined by 41.4 percent; Alaska, by 63.2 percent; and the rest of the United States, by 36.3 percent. As of 2008, the United States crude oil production had declined to a little more than 1.8 billion barrels per year, or an average of 4.96 million barrels per day (BPD). California's annual crude oil production was approximately 238.6 million barrels during 2008, averaging 652,000 BPD. Figure 4.3 breaks down U.S. crude oil production by source between 1986 and 2008.

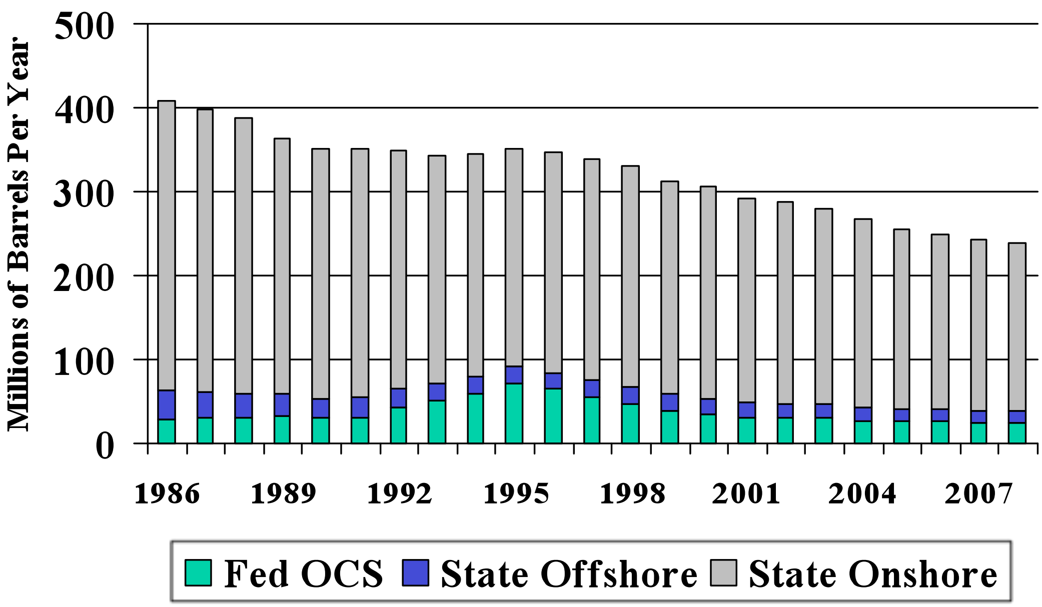
Figure 4.3: U.S. Crude Oil Production (1986 to 2008)



Sources: California Division of Oil, Gas, and Geothermal Resources, Alaska Department of Revenue, and EIA.

Figure 4.4 illustrates California's crude oil production over the same period from three sources: onshore, state offshore waters, and federal OCS.[cxliii]

Figure 4.4: California Crude Oil Production (1986 to 2008)



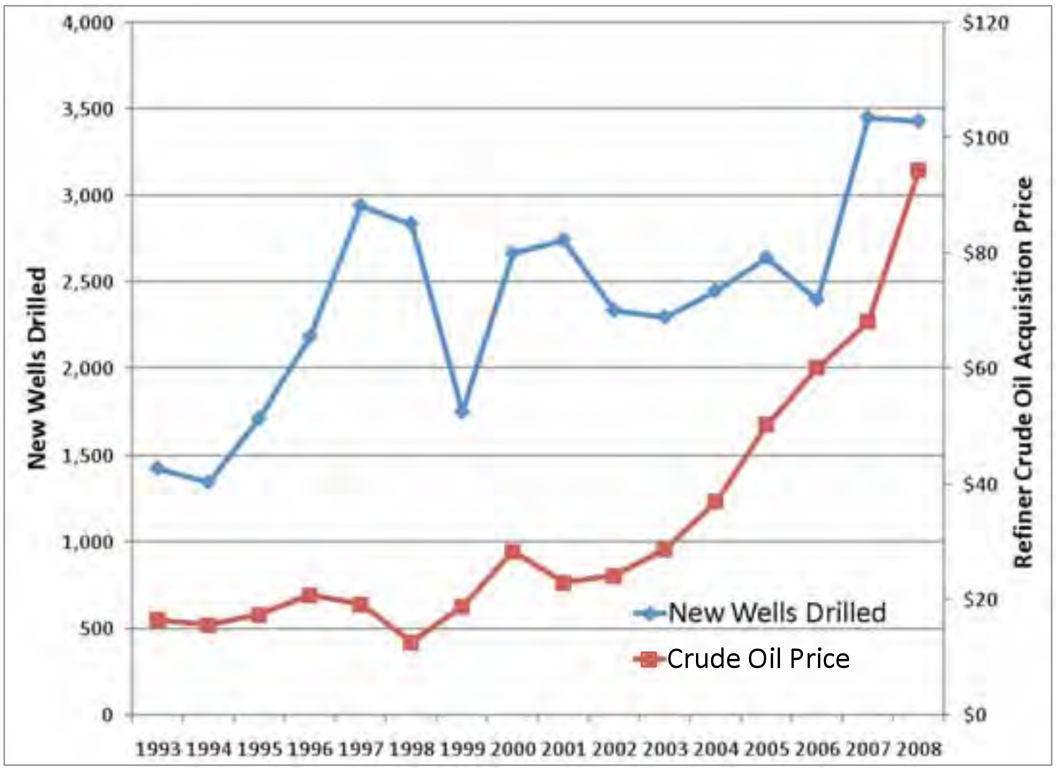
Source: California Division of Oil, Gas, and Geothermal Resource

California Crude Oil Production Decline Rates

One factor that contributes to increasing volumes of imported crude oil over time is the steady decline of California crude oil production. As local quantities of crude oil diminish, refiners must compensate by importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at an even greater rate than California production, refiners must seek substitute crude oil from foreign sources.

Over the last 10 years, California's crude oil production has declined at an average rate of 3.2 percent per year. Between 2006 and 2008, the decline rate is lower, averaging 2.2 percent per year. The decreasing decline rates over the last couple of years may be in response to an increased level of drilling prompted by rising crude oil prices over the same period. Figure 4.5 illustrates the relationship between crude oil prices and increasing well drilling.

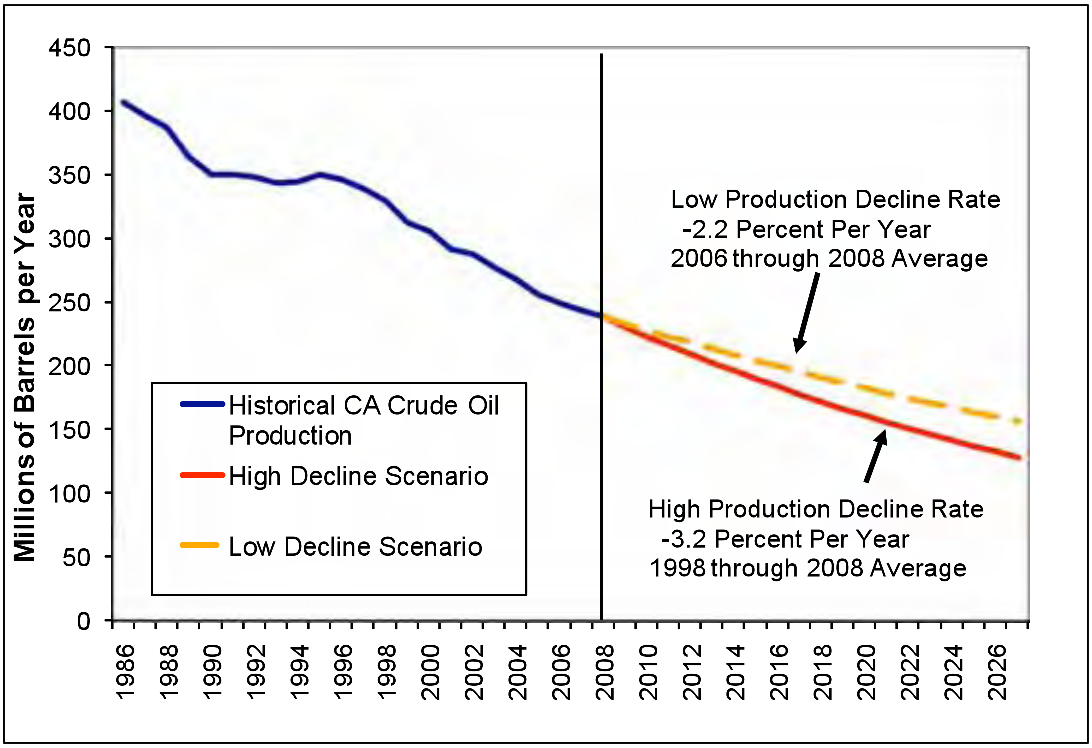
Figure 4.5: California New Wells Drilled vs. Crude Oil Price



Sources: California Division of Oil, Gas, and Geothermal Resources and the Energy information Administration

Despite the increased drilling in California over the last decade, crude oil production continues to decline, albeit at a slightly lower rate over the last couple of years. Figure 4.6 shows the historical and projected crude oil production levels based on a range of decline rates. The higher production decline rate is a trend based on the last decade of historical data. The less steep decline rate of 2.2 percent per year is based on the most recent three years of statistics.

Figure 4.6: California Crude Oil Production Forecast 2009–2030



Sources: California Division of Oil, Gas, and Geothermal Resources and the California Energy Commission

California Refinery Crude Oil Processing Capacity

In California 19 refineries are operating; they process an average of 1.8 million BPD of crude oil.[cxliv] In the initial processing step, distillation process units convert crude oil to a variety of petroleum blendstocks that are combined to form gasoline, diesel, and jet fuel. Most refiners normally perform periodic maintenance at their facilities during the winter months. Occasionally, a refiner may elect to expand slightly the capacity of its crude oil distillation equipment if the project meets environmental guidelines and can be justified as having a sufficient economic return for the cost of the project. This gradual increase of distillation capacity—*refinery creep*—is the second primary factor that can contribute to increasing imports of crude oil for California.

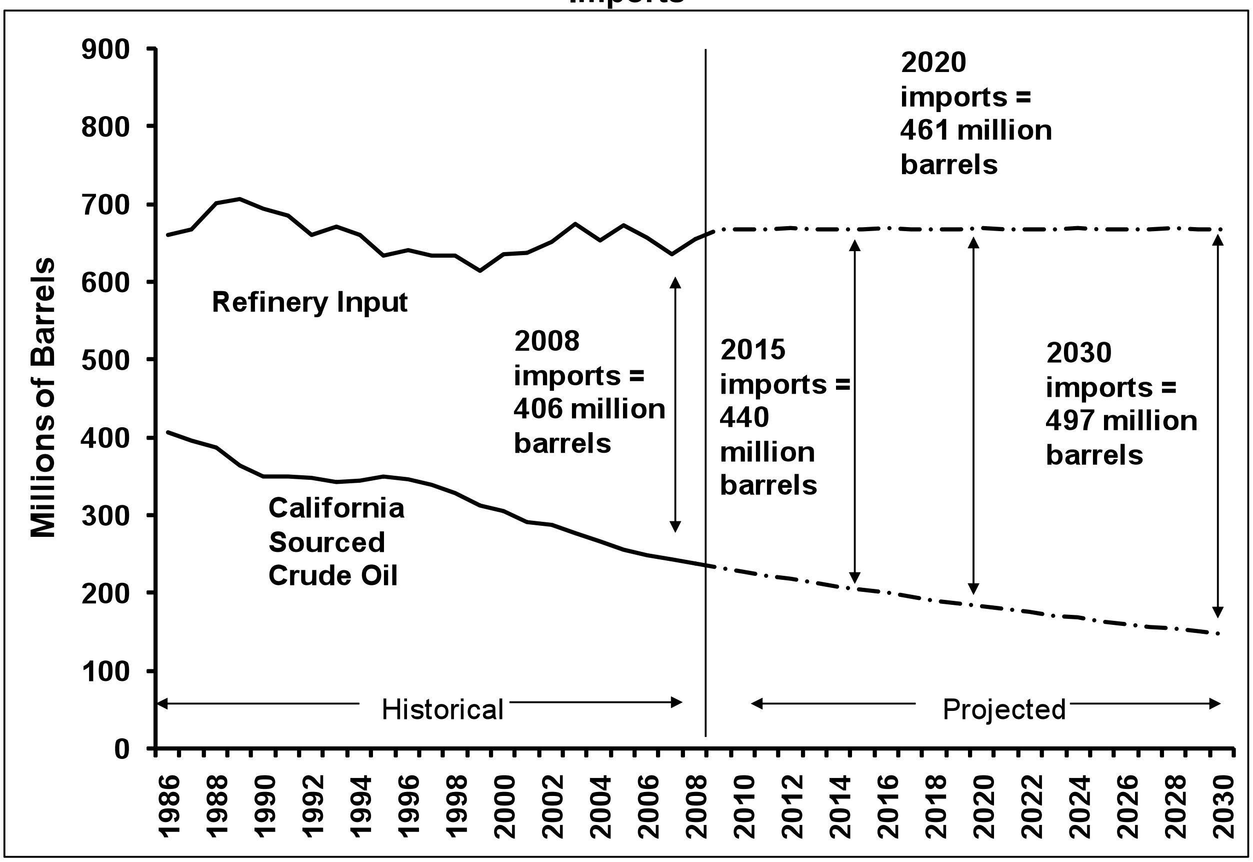
Between 2001 and 2008, California refinery creep for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year. Staff selected the lower crude oil distillation capacity growth rate for calculating the High Case for crude oil imports. Staff has elected to use a flat distillation capacity growth rate of zero percent per year over the forecast period for calculating the Low Case crude oil imports. The primary reason for use of a flat rate is the lower gasoline demand forecasts that have resulted from improved fuel economy standards and increased mandated levels of renewable fuels. Further, the U.S. EIA has also forecast in its Reference Case a refinery distillation capacity growth rate in the western region of the United States (referred to as Petroleum Administration for Defense District V or PADD V) that is nearly identical (0.47 percent) over the same forecast period.[cxlv] These two distillation capacity growth rates bounded the lower and upper limits of refinery creep for this analysis.

Since refineries do not process crude oil when the distillation units are undergoing maintenance or are temporarily out of service from an unplanned refinery outage, their utilization rates (a measure of crude oil processed per day relative to the maximum capacity of the equipment) will be at a level of less than 100 percent. For all of the refineries operating in California since 1999, the combined utilization rate has averaged 89.9 percent. For this work, staff assumed that this utilization rate would remain constant over the next 21 years.

Crude Oil Import Forecast

To estimate a range of incremental crude oil imports for California, staff compared the trends of crude oil production decline rates and gradual refinery distillation capacity growth to produce a Low and High Case forecast. Figure 4.7 depicts the Low Case.

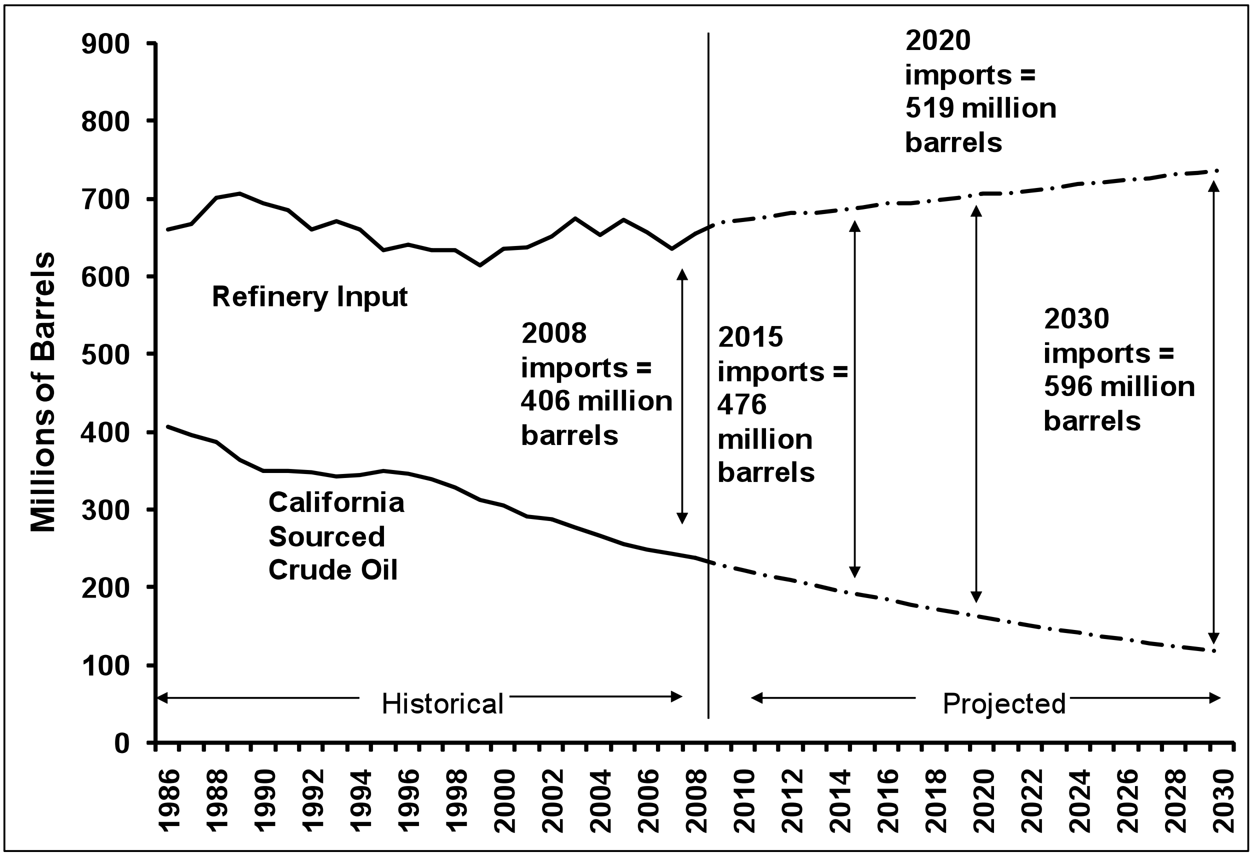
Figure 4.7: Low Case Forecast for California Crude Oil Imports



Sources: California Energy Commission analysis and Petroleum Industry Information Reporting Act database

Under the Low Case projection, annual crude oil imports are forecast to increase by 34 million barrels between 2008 and 2015 (8.5 percent increase), by 55 million barrels by 2020 (13.6 percent increase), and by 91 million barrels by 2030 (22.5 percent increase compared to 2008). To obtain these projections, staff assumed that distillation capacity increases (refinery creep) would be at the lower rate of zero percent per year, while the decline rate of California crude oil production would be at the lower rate of 2.2 percent per year. Using higher rates for both crude oil production decline and refinery creep, crude oil imports are expected to grow faster. Under the High Case projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015 (17.3 percent increase), by 113 million barrels by 2020 (28.0 percent increase), and by 190 million barrels by 2030 (47.0 percent increase compared to 2008). Figure 4.8 illustrates the High Case projection for California crude oil imports.

Figure 4.8: High Case Forecast for California Crude Oil Imports



Sources: California Energy Commission analysis and Petroleum Industry Information Reporting Act database

As each of the two previous figures indicates, the use of different rates for crude oil production decline and refinery creep can significantly alter the estimated range of incremental crude oil imports. Table 4.1 combines the various rates into a single table for both the mid-term (2020) and longer-term (2030) periods of the forecast.

Table 4.1: Import Projections for Entire State

Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	35	55	91	49	77	122
0.45 Percent	56	92	160	70	114	191

Source: California Energy Commission

Although staff did not forecast the regions of the world that might provide the source of future crude oil imports, Baker & O'Brien recently presented its projections for Southern California that are contained in Appendix Table C.2.[cxlvi] The next step in the analysis involved an estimate of the portion of the incremental crude oil imports for the entire state that would be delivered to Northern and Southern California, respectively. Based on recent historical trends, staff assumed that 60 percent of the incremental crude oil imports over the forecast period would be delivered to marine terminals in Southern California, with the balance (40 percent) handled by marine berths in the San Francisco Bay Area.[cxlvii] Table 4.2 shows how the incremental import projections for Southern California can vary by changing the assumed rates for crude oil production decline and refinery creep.

Table 4.2: Import Projections for Southern California

Incremental Southern California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	21	33	55	29	46	73
0.45 Percent	33	55	96	42	68	114

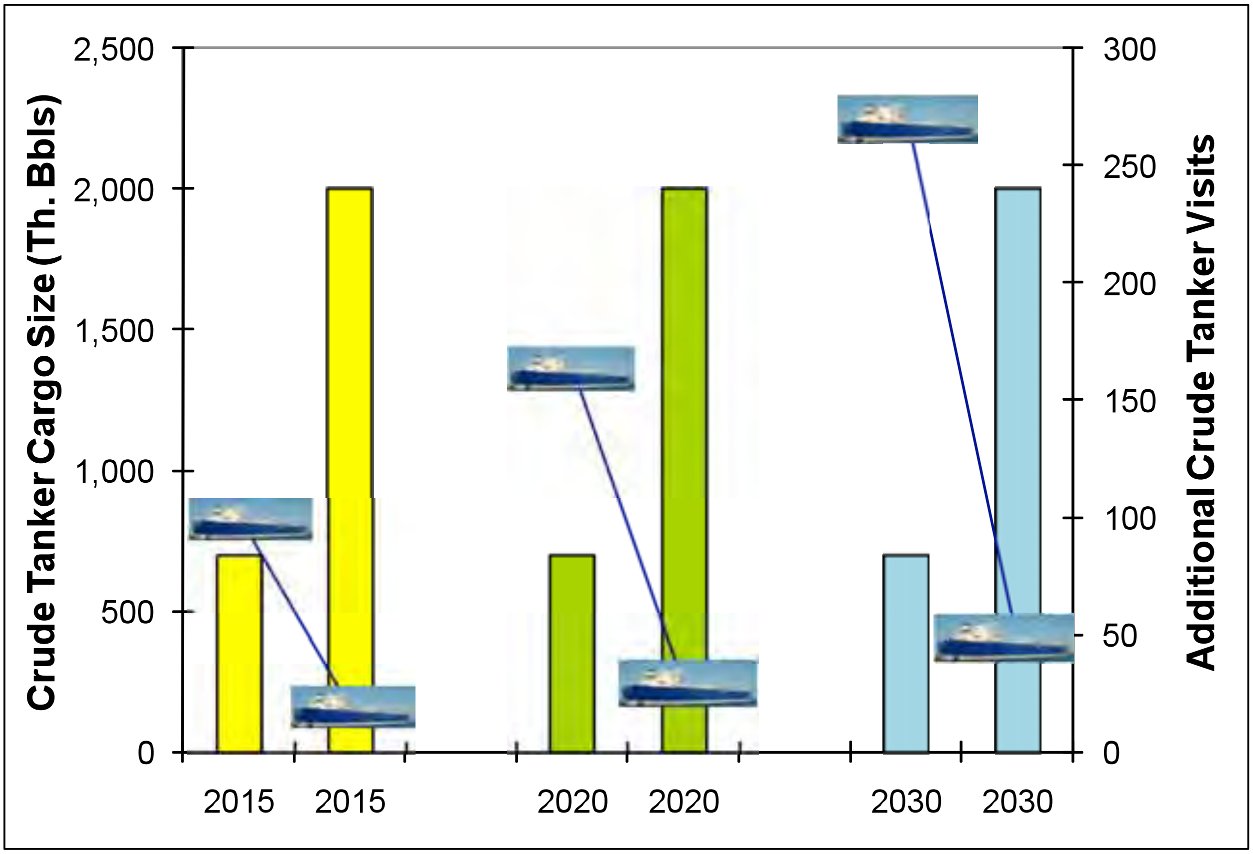
Source: California Energy Commission

Crude Oil Tankers – Incremental Voyages

The increased imports of crude oil are expected to result in a greater number of marine vessels (referred to as crude oil tankers) arriving in California ports. Staff has examined recent import information to determine an average cargo size per crude oil tanker import event. For calculating additional crude oil tanker trips, staff used an upper limit of 2 million barrels of cargo capacity per import event and a lower limit of 700,000 barrels capacity. The upper limit represents the storage capacity of a very large crude carrier (VLCC). The lower range is the capacity of typical foreign crude oil tankers, referred to as Aframax (80 thousand to 119 thousand deadweight tonnage). This scenario assumed that the bulk of the incremental imports of crude oil over the near term will originate from foreign sources and be transported on Aframax marine vessels.

Using these two estimates for crude oil tanker capacity, staff calculated 17 to 100 additional crude oil tanker arrivals per year by 2015, 28 to 162 by 2020, and 46 to 272 additional arrivals per year by 2030. The broad range for the estimate is a consequence of the large difference in capacity between the Aframax and VLCC storage capacities, as well as the annual incremental crude oil import forecast differences between the High and Low cases.[cxlviii] Figure 4.9 depicts the broad range of incremental crude oil tanker import events at various points of the forecast. The vertical axis on the left side is for the size of the crude oil tanker cargo capacity, while the vertical axis on the right side is for the number of additional crude oil tanker visits in a specific year at some point during the forecast period.

Figure 4.9: Incremental Crude Oil Tanker Visits



Source: Energy Commission staff analysis of forecast and crude oil tanker attributes.

Crude Oil Storage Capacity–Anticipated Growth

The importation of incremental volumes of crude oil will not only necessitate an increased number of crude oil tanker visits, but will also require a larger storage tank capacity for the marine facilities receiving the additional cargoes. The Energy Commission staff has calculated additional storage tank capacity that would have to be constructed to handle the incremental imports of crude oil. This scenario assumes that most of the existing marine terminals are at or near maximum operating capacity. Two incremental storage tank throughput rates were used to calculate the additional crude oil storage tank capacity estimates. The first rate uses a design capacity throughput similar to the proposed crude oil import project at Berth 408 in San Pedro Harbor, approximately 1 million barrels of storage capacity per 23 million barrels of imports per year.[cxlix] The second rate assumes a slower cycling of the storage tanks, yielding a conversion rate of about 1 million barrels of storage capacity per 12 million barrels of imports per year. Based on these assumptions, the incremental crude oil storage capacity needed in California would amount to between 1.5 million and 5.8 million barrels by 2015; between 2.4 million and 9.5 million barrels by 2020; and between 4.0 million and 15.9 million barrels of storage capacity by 2030. Nearly 60 percent of this incremental storage capacity will need to be constructed in Southern California, where spare land for such projects is at a premium.

Alternative Assumptions – Impact on Crude Oil Import Forecast

Crude oil imports for California refiners could be less than initial staff projections indicate under a different scenario: expanded exploration and production off of California's coast. Expanded offshore drilling and production are a contentious issue that has received increased interest due to recent federal and state activities.

Timing and Supply Potential of Expanded Offshore Drilling Scenario

The federal moratoria for drilling in federal OCS waters expired when Congress took no action to reinstate the ban before the new federal fiscal year began on October 1, 2008. Before that date, the Minerals Management Services (MMS) initiated a new five-year lease process that included the moratoria OCS areas. The moratoria areas off the coast of California are estimated by MMS to contain between 5.8 billion and 15.8 billion barrels of Undiscovered Technically Recoverable Resources (UTRR) crude oil.[cl] Over half of this estimated crude oil resource is located in federal waters off the coast of Southern California. However, the federal MMS estimates that between 53 and 78 percent of these reserves would be economically recoverable based on crude oil prices ranging from $60 to $160 per barrel.[cli]

Prior to development of any of the moratoria OCS areas, there are two discrete steps that must be undertaken: development of a five-year program and planning for a specific sale. *Together, these processes can take between 3.5 and 5 years to complete, absent any intervening litigation which would extend the timeline.* These two MMS regulatory processes are briefly described below.

Once an oil company is a successful recipient of a lease, it would be able to initiate the processes of developing an exploration plan, obtain the necessary capital, construct the drill rigs, drill exploratory wells, assess drill results and mapping analysis, construct a drilling platform, drill production wells, and construct pipelines from the platform to onshore facilities before new crude oil production could begin.

Due to the lengthy federal regulatory process and the numerous developmental steps, it is no surprise that the U.S. EIA estimates that it could take up to 10 years for new crude oil production to begin from the moratoria OCS areas.[clii]

Developing a Five-Year Program

The preparation of the schedule for the OCS oil and natural gas lease sales is governed by Section 18 of the Outer Continental Shelf Lands Act (OCSLA), which was added to the OCSLA in 1978. Section 18 of the OCSLA requires the Secretary of the Interior to prepare and maintain an OCS oil and natural gas leasing program.

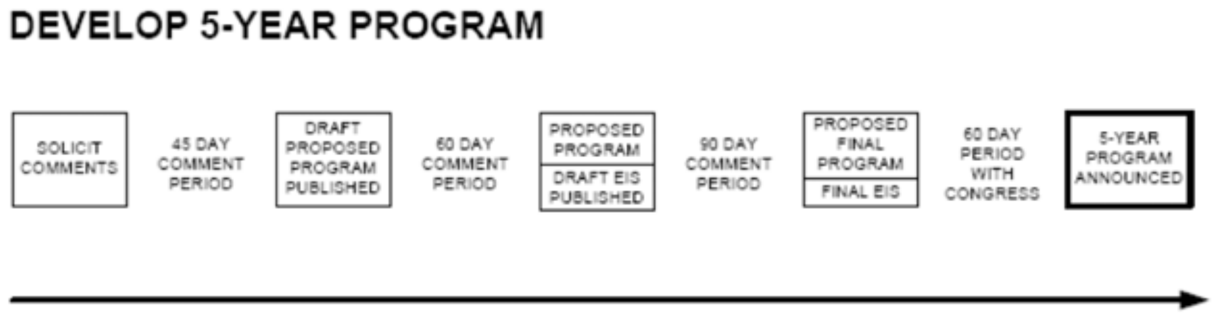
When approved, the leasing program consists of scheduled lease sales for a five-year period, along with policies pertaining to the size and location of sales and the receipt of fair-market value. The schedule indicates the timing and location of sales and shows the presale steps in the process that lead to a competitive sealed bid auction for a specific OCS area. In preparing a new five-year program, the Secretary solicits comments from coastal state governors and localities, tribal governments, the public, the oil and natural gas industry, environmental groups, affected federal agencies, and the Congress.

The MMS requests comments at the start of the process of developing a new program and following the issuance of each of the first two versions:

- The draft proposed program with a 60-day comment period.
- The proposed program with a 90-day comment period.

The third and last version, the proposed final program, is prepared with a 60-day notification period following submission to the President and Congress. After 60 days, if Congress does not object, the Secretary may approve the program.

The entire five-year lease program process takes from 18 to 36 months to complete.

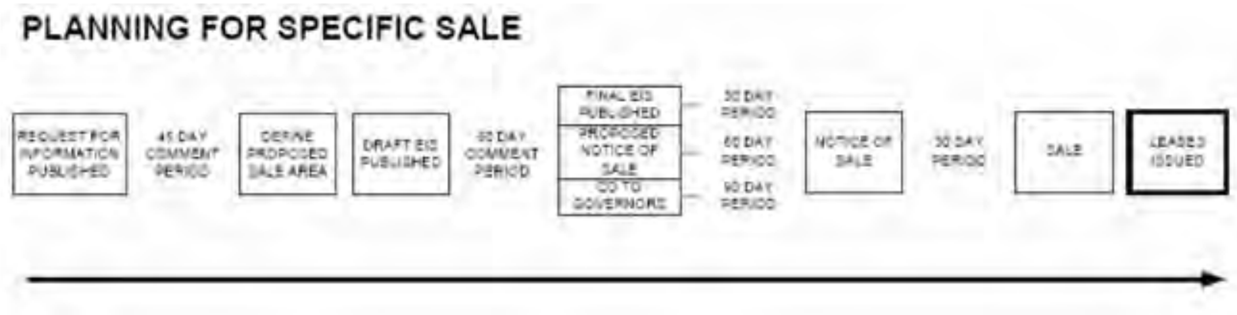


On July 30, 2008, MMS announced that it was initiating a new five-year process.[cliii] The *Draft Proposed 5-Year OCS Oil and Gas Leasing Program for 2010-2015* was released and comments were due September 21, 2009.

Planning for a Specific Sale

After adoption of a five-year leasing program, the usual first step in the sale process for an area is to publish simultaneously in the Federal Register a Call for Information and Nominations (Call) and a Notice of Intent (NOI) to prepare an environmental impact statement (EIS). Comments are usually due 45 days after the Call and NOI are published. Some proposed sale areas may include an additional first step—a request to industry to solicit comments and interest in the specific area.

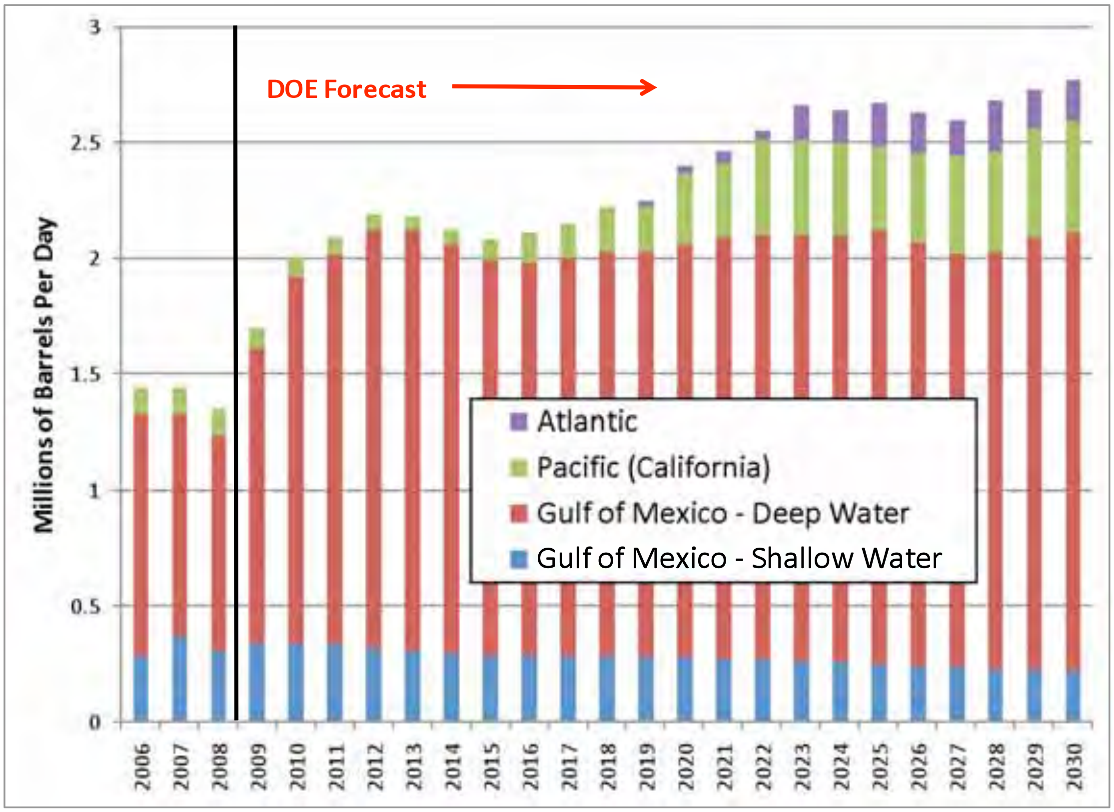
The process from the Call/NOI to the sale may take two or more years.



The U.S. DOE has estimated the pace and quantity of additional crude oil production that could be achieved from expanded drilling in federal OCS waters for the lower 48 states. The incremental quantities are illustrated in Figure 4.10. Under this scenario, OCS crude oil production is forecast to increase from 1.35 million barrels per day in 2008 to approximately 2.77 million barrels per day by 2030. New production associated with lifting of the moratoria is assumed to begin in 2015, since the process to develop these new areas could require at least five years. (See discussion above.) Compared to 2014, crude oil production would increase from 2.12 million barrels per day to 2.77 million barrels per day by 2030, approximately 650,000 barrels per day higher by the end of the forecast period. The majority (65 percent by 2030) of this incremental OCS crude oil production is forecast by the U.S. DOE to occur in the Pacific region (essentially California). In fact, nearly 74 percent of the cumulative incremental crude oil production is forecast to originate from the Pacific (California) OCS region, 1.5 billion barrels of the total 2.1 billion barrels incremental crude oil production between 2014 and 2030.

If federal, state, and local governments were to pursue such an expanded drilling scenario, a new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations would likely be required to achieve this forecast level of incremental crude oil production. It is unknown what portion of the untapped economically recoverable crude oil OCS reserves are close to any of the existing 22 offshore platforms (in federal OCS waters) such that directional drilling could be employed to increase production without constructing any new platforms and associated infrastructure.[cliv] However, it is unlikely that these OCS crude oil reserves could be completely accessed without the construction of new infrastructure that is currently undetermined in scope and cost.

Figure 4.10: OCS Crude Oil Production Forecast – No Moratoria



Source: Energy Commission staff analysis of data from the Department of Energy, Office of Petroleum Reserves

Impact on California Crude Oil Import Forecast of Lifting OCS Moratoria

If the lifting of the OCS moratoria remains in effect and development proceeds as forecast by U.S. DOE off the coast of California, the incremental crude oil production could have a significant impact on the forecast of crude oil imports, as illustrated in Table 4.3.

Table 4.3: Moratoria Scenario – Import Projections for Entire State

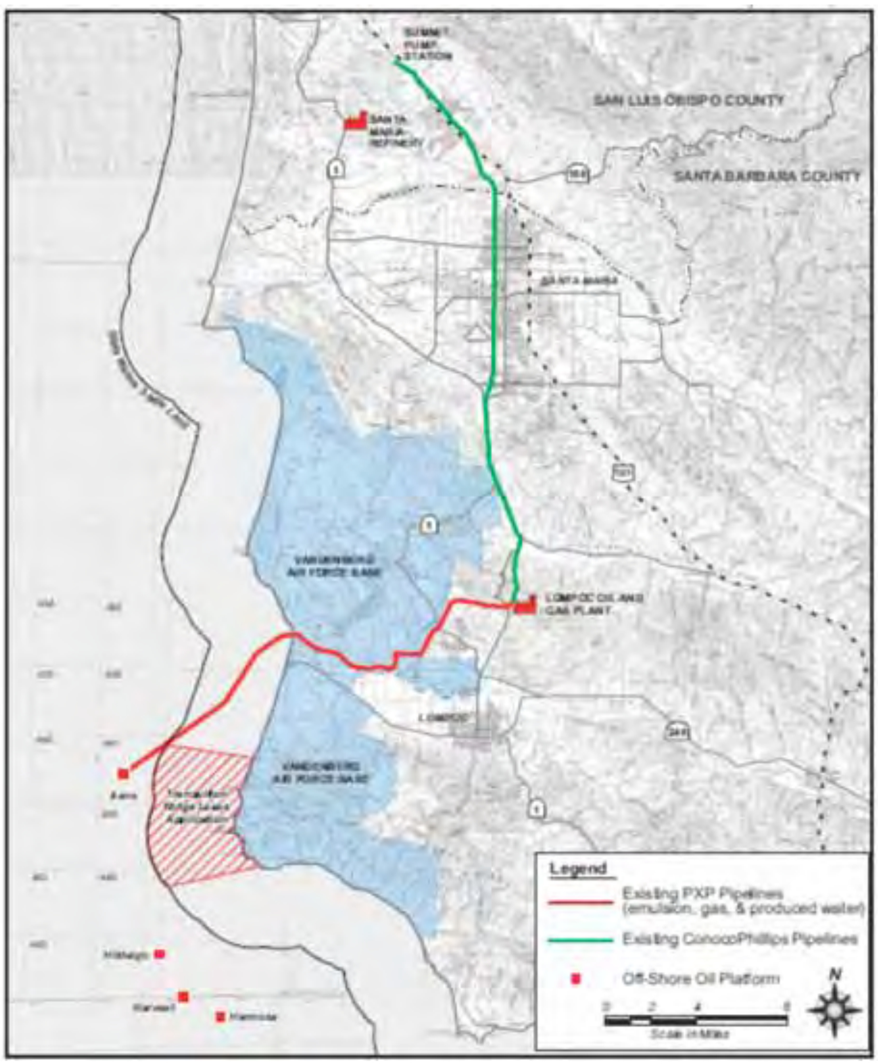
Incremental California Crude Oil Imports - Millions of Barrels						
Distillation Capacity Growth Rate	Low Rate of Crude Oil Decline - 2.2%			High Rate of Crude Oil Decline - 3.2%		
	2015	2020	2030	2015	2020	2030
Zero Percent	24	-36	-62	38	-14	-32
0.45 Percent	45	1	7	59	22	37

Source: California Energy Commission

Impact on California Crude Oil Import Forecast of Tranquillon Ridge Project

Although the scenario of expanded drilling off of California's coast in OCS waters is a contentious and complicated process that would entail a significant period to achieve any tangible results (if allowed to proceed), there is another effort underway off the coast of California that could result in additional quantities of crude oil being produced from an existing offshore platform. The Plains Exploration and Production Company project involves drilling of additional wells from its existing Platform Irene (that lies in federal OCS waters off of Vandenberg Air Force Base) into a crude oil field referred to as Tranquillon Ridge (Figure 4.11).

Figure 4.11: Tranquillon Ridge Project Location



Source: County of Santa Barbara Planning and Development, Final EIR, Figure 2-1, page 2-29, April 2008

There are four distinct differences between the proposed Tranquillon Ridge Project and the expanded offshore drilling in OCS waters scenario:

- Scope of potential incremental production is significantly less.
- Timing to initiate new production is more rapid.
- No need for new offshore platforms and associated infrastructure.
- Sunset of activities.

The federal OCS expanded drilling scenario is estimated to result in an increase of federal OCS crude oil production of 200,000 BPD by 2020 (versus 2008), as compared to an estimate of between 8,000 and 27,000 BPD from the Tranquillon Ridge Project.[clv] The Tranquillon Ridge Project is assumed to achieve new crude oil production within a year of renewed drilling activity from existing Platform Irene. Assuming the project was granted permission to move forward in late 2009, new production could begin in late 2010 or early 2011.[clvi] Expanded drilling off the coast of California in federal OCS waters would require far more time to begin new crude oil production, estimated at the earliest by 2015. Finally, there is a provision in the Tranquillon Ridge Project agreement to end operations by 2024. There are no such proposals or requirements being considered at this time for the new five-year lease program being developed by MMS for expanded drilling in federal OCS waters.

Other Issues Related to Crude Oil Infrastructure

A California Strategic Petroleum Reserve (SPR) for crude oil was a topic raised during IEPR proceedings earlier this year. The subject of strategic storage of crude oil in California as a means to provide crude oil to refineries in the event of a supply disruption is also a concept that was previously discussed during the *2007 IEPR* proceedings. At that time, the Office of Petroleum Reserves (a U.S. DOE agency) was examining potential alternative sites for placement of strategic crude oil inventories that would be beneficial during a crude oil supply disruption episode associated with a temporary loss of a portion of the crude oil import infrastructure (due to either a significant natural disaster or intentional act of sabotage) or a temporary loss of supply from a particular source location or country.

Currently, there are no plans by U.S. DOE to create an SPR West Coast expansion. Although staff believes that the placement of crude oil in California could decrease the likelihood of refinery production decline in the event of a temporary loss of crude oil deliveries, there has been no engineering analysis performed to date for quantifying an estimated range of cost for such a project.

CHAPTER 5: California Petroleum Products Imports Forecast

Overview

The effects of trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states determine the rate at which California's imports of transportation fuels will increase during the forecast period. This section contains a discussion of the specific factors that staff assessed, the method employed when conducting the analysis, and a description of additional factors that can increase the level of uncertainty inherent in this work. The primary purpose of this analysis is to quantify a range of incremental imports of transportation fuels for the regional market and to identify any potential constraints within the distribution infrastructure that could impede supplies of transportation fuels for California consumers and businesses.

The global and domestic economic downturn over the last 12+ months, coupled with rising fuel costs that culminated in the tremendous crude oil price spike of 2008, has contributed to a multiyear decline in transportation fuel demand that was last experienced during the late 1970s.[clvii] This significant development has reduced imports of petroleum products and even partially contributed to the closure of a California refinery and idling of nearly all of California's ethanol facilities. Increased use of renewable fuels that will result from recently adopted federal and state mandates, along with increased vehicle average fuel efficiency, is forecast to negatively affect the growth of traditional petroleum-based transportation fuels over the next 20 years. Some of these expected changes to long-standing trends could be rather significant, potentially signaling the passage of a peak for California petroleum transportation fuel demand and imports of refined petroleum fuels.

California Refinery Production Capacity

Over the last decade, production of transportation fuels from California refineries has not normally kept pace with consumer demand, resulting in greater quantities of imported gasoline, diesel, jet fuel, and alternative fuels. However, over the last couple of years, the need for imports has lessened as demand for traditional transportation fuels (gasoline, diesel and jet fuel) has declined by 6.2 percent since 2007.[clviii] The level of transportation fuel imports over the forecast period can be influenced by the rate at which refinery capacity grows over time. Production of transportation fuels depends on:

- Maximum capacity to process crude oil (distillation capacity)
- The number of days refineries operate at normal rates during the year (utilization rate)
- Maximum capacity to process additional refinery feedstocks (process unit capacity)

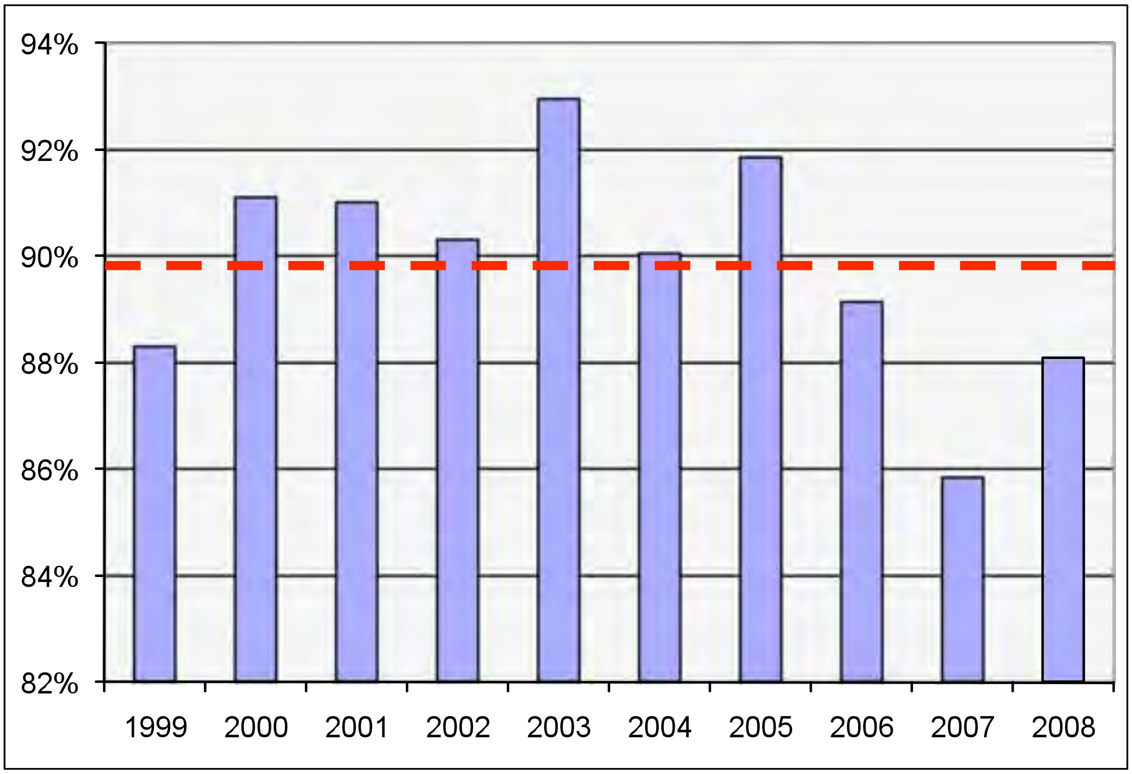
Crude Oil Processing (Distillation) Capacity

If California refineries process additional quantities of crude oil each year, the output of petroleum products from those refineries should be greater. The gradual growth of California refinery capacity to process crude oil, referred to as refinery creep, is assumed to grow at a slower rate than that observed over the last several years. In California 19 refineries are operating; they process an average of 1.8 million BPD of crude oil.[clix] In the initial processing step, distillation process units convert crude oil to a variety of petroleum blendstocks that are combined to form gasoline, diesel, and jet fuel. Most refiners normally perform periodic maintenance at their facilities during the winter months. Occasionally, a refiner may elect to expand slightly the capacity of its crude oil distillation equipment if the project meets environmental guidelines and can be justified as having a sufficient economic return for the cost of the project.

Between 2001 and 2008, California refinery creep for crude oil distillation capacity increased at an average rate of 0.84 percent per year. Between 2003 and 2008, the refinery creep rate was a little more than half that level at 0.45 percent per year. Staff selected the lower crude oil distillation capacity growth rate for calculating the Low Case for transportation fuel imports. Staff has elected to use a distillation capacity growth rate of zero percent per year over the forecast period for purposes of calculating the High Case for transportation fuel imports. Further, the U.S. EIA has also forecast in their Reference Case a refinery distillation capacity growth rate in PADD V that is nearly identical (0.47 percent) over the same forecast period.[clx] These two distillation capacity growth rates were used as part of the analysis to estimate the lower and upper limits of transportation fuel imports.

Since refineries do not process crude oil when the distillation units are undergoing maintenance or are temporarily out of service from an unplanned refinery outage, their utilization rates (a measure of crude oil processed per day relative to the maximum capacity of the equipment) will be at a level of less than 100 percent. For all of the refineries operating in California since 1999, the combined utilization rate has averaged 89.9 percent. For purposes of this work, staff assumed that this utilization rate would remain constant over the next 21 years. The use of a constant crude oil processing capacity would increase the transportation fuel import forecast. The potential import impact of this scenario is discussed later in this chapter. Figure 5.1 depicts annual and average crude oil distillation utilization rates over the last decade.

Figure 5.1: California Refineries – Crude Oil Utilization Rates (1999-2008)



Sources: PIIRA and Energy Commission analysis.

Process Unit Capacity Growth

California refineries use other types of equipment to further refine the crude oil initially processed by the crude oil distillation units. These process units can also be used to convert refinery feedstocks, purchased from outside the refinery, into petroleum blendstocks suitable for creating gasoline and other transportation fuels. Over the forecast period, the process unit capacity is expected to increase at a rate that will be sufficient to accommodate the additional feedstocks generated by the continuously expanding crude oil distillation process capacity.

Exports of Transportation Fuels to Neighboring States

Nevada and Arizona do not have any refineries that can produce transportation fuels. As a consequence, these states must import all of the transportation fuels that they consume from refineries located outside their borders. Refineries located in California export petroleum products via pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. The Kinder Morgan Pipeline Company (KMP) owns and operates this network of interstate pipelines.

Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. In 2006, approximately 55 percent of Arizona's demand was met by products exported from California. However, that percentage dropped to just 35 percent by 2008 as refiners and other marketers shifted source of supply away from California to Texas and New Mexico. The larger balance of transportation fuels consumed in Arizona is now delivered in a petroleum product pipeline that originates in Western Texas on a section of the KMP system referred to as the East Line. Figure 5.2 depicts the KMP petroleum product pipeline system in the Southwest United States.

Figure 5.2: Kinder Morgan Interstate Pipeline System

Source: Kinder Morgan Pipeline company.

If expansion of California refinery capacity fails to keep pace with demand growth for transportation fuels in California, Nevada, and Arizona, imports of petroleum products and alternative fuels will grow over time. Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market.

Staff used a variety of analytical approaches to develop transportation fuel demand forecast for Arizona and Nevada. The latest forecasted growth of commercial passenger jet activity by the FAA was used to obtain an estimate for jet fuel demand for Arizona and Nevada.[clxi] Only one base case jet fuel demand forecast was developed for Arizona and Nevada, rather than Low and High demand assessments.

Diesel fuel demand for the neighboring states was estimated using specific cases from the *2009 Annual Energy Outlook (AEO)* forecast by the U.S. EIA for the Mountain census region of the United States.[clxii] The Low Demand Case used the Updated Reference Case growth projections for transportation diesel fuel in the Mountain Region.[clxiii] This particular scenario from U.S. EIA would be considered a High Oil Price case. The rate of growth for diesel fuel from this U.S. EIA scenario was applied to the 2008 starting point in both states to obtain a forecast for total diesel fuel demand. The High Demand case for diesel fuel in the neighboring states was derived by using the Low Oil Price scenario from U.S. EIA's *2009 AEO*.[clxiv] Once again, the forecast under this scenario for the Mountain census region was used to determine a rate of demand that was applied to the same 2008 starting point for each of the two states.

The gasoline demand forecasts for Arizona and Nevada used the same approach as that employed for diesel fuel. However, as was the case with the California gasoline demand calculations, these initial forecasts had to be revised to reflect the additional use of renewable fuel (mainly ethanol) that is part of the mandated requirements of the federal RFS2. Fair share volumes of biofuels were first calculated for Arizona and Nevada, followed by a rebalancing of the gasoline demand forecast to compensate for the additional quantity of ethanol associated with RFS2 compliance. For calculating forecasted quantities of E85, maximum ethanol concentration in Arizona and Nevada was assumed to be 10 percent by volume (just like California) over the forecast period. The U.S. EPA is scheduled to rule sometime later this year whether the ethanol blending limit can increase to 15 percent by volume. If so, it is recognized that the volumes of E85 forecast in Arizona and Nevada could be less than indicated by this analysis. However, it is unknown to what extent E15 blends would be permissible in the neighboring states. This is especially the case with Arizona given that state's Cleaner Burning Gasoline (CBG) regulations.

Table 5.1 provides historical and forecasted quantities of transportation fuels for Arizona. Gasoline demand under the Low Case is nearly flat over the forecast period, and E85 sales grow significantly in response to the RFS2 mandates. Diesel and jet fuels recover from a slight decline at the outset of the forecast and settle at levels that are at least 50 percent higher by 2030 when compared to 2008 totals.

Table 5.1: Arizona Transportation Fuel Demand

Historical and Forecast (Thousands of Barrels per Day)

	Gasoline		E85		Diesel Fuel		Jet	Totals	
Year	Low	High	Low	High	Low	High	Fuel	Low	High
2006	177.0	177.0	0.0	0.0	58.0	58.0	33.8	268.9	268.9
2007	184.5	184.5	0.0	0.0	57.9	57.9	35.5	277.9	277.9
2008	177.1	177.1	0.0	0.0	60.2	60.2	33.1	270.4	270.4
2010	186.9	187.4	0.0	0.0	59.5	62.1	28.5	274.8	278.0
2020	177.3	210.6	23.3	21.4	74.0	79.2	36.9	311.5	348.1
2030	175.7	233.6	33.5	30.6	90.9	101.6	51.9	351.9	417.6

Incremental Demand Versus 2008 (Thousands of Barrels per Day)

2010	9.8	10.3	0.0	0.0	-0.7	1.9	-4.6	4.5	7.6
2020	0.2	33.5	23.3	21.4	13.7	19.0	3.9	41.2	77.7
2030	-1.4	56.5	33.5	30.6	30.6	41.4	18.8	81.5	147.2

Percentage Change Compared to 2008

2010	5.5%	5.8%	NA	NA	-1.2%	3.1%	-13.9%	1.7%	2.8%
2020	0.1%	18.9%	NA	NA	22.8%	31.5%	11.7%	15.2%	28.7%
2030	-0.8%	31.9%	NA	NA	50.8%	68.7%	56.9%	30.1%	54.5%

Source: California Energy Commission analysis

Table 5.2 shows the historical and forecast transportation fuel demand levels for Nevada over the same period. Results are similar for gasoline, with a strong increase in renewable fuels.

Table 5.2 Nevada Transportation Fuel Demand

Historical and Forecast (Thousands of Barrels per Day)

	Gasoline		E85		Diesel Fuel		Jet	Totals	
Year	Low	High	Low	High	Low	High	Fuel	Low	High
2006	76.1	76.1	0.0	0.0	49.0	49.0	34.7	159.8	159.8
2007	73.5	73.5	0.0	0.0	47.7	47.7	35.2	156.4	156.4
2008	70.0	70.0	0.0	0.0	47.7	47.7	34.2	151.8	151.8
2010	73.8	74.0	0.0	0.0	47.1	49.1	29.1	150.0	152.3
2020	70.1	83.2	9.2	8.4	58.5	62.7	39.9	177.7	194.2
2030	69.4	92.3	13.2	12.1	71.9	80.4	61.1	215.6	245.8

Incremental Demand Versus 2008 (Thousands of Barrels per Day)

2010	3.9	4.1	0.0	0.0	-0.6	1.5	-5.1	-1.8	0.5
2020	0.1	13.2	9.2	8.4	10.9	15.0	5.7	25.9	42.4
2030	-0.6	22.3	13.2	12.1	24.2	32.7	26.9	63.8	94.0

Percentage Change Compared to 2008

2010	5.5%	5.8%	NA	NA	-1.2%	3.1%	-14.9%	-1.2%	0.3%
2020	0.1%	18.9%	NA	NA	22.8%	31.5%	16.8%	17.1%	27.9%
2030	-0.8%	31.9%	NA	NA	50.8%	68.7%	78.5%	42.0%	61.9%

Source: California Energy Commission analysis

Pipeline exports to Arizona and Nevada from California were forecast to determine what range of potential impact there could be for supplies either originating at California refineries or imported through California's marine terminal infrastructure. The Low Export Case from California assumes low fuel demand forecasts in Arizona and Nevada in conjunction with the East Line supplying barrels into Arizona preferentially over barrels being supplied from California through the West Line. Table 5.3 shows the estimated volume of pipeline exports originating from within California. One prominent outcome of this analysis is that the federal RFS2 requirements will essentially negate any demand growth for gasoline over the forecast period. Even so, incremental pipeline exports are still forecast to increase, albeit modestly over the next 20 years.

Table 5.3: Pipeline Exports to Arizona and Nevada From California – Low Case

Historical & Forecast (Thousands of Barrels per Day)

	Gasoline		Diesel Fuel		Jet Fuel		Totals	
Year	AZ	NV	AZ	NV	AZ	NV	AZ	NV
2006	63.2	71.7	38.7	49.0	31.2	34.7	133.1	155.4
2007	50.3	70.9	30.0	47.7	32.4	35.2	112.7	153.8
2008	21.8	67.4	25.0	47.7	29.2	34.2	75.9	149.3
2010	21.4	66.4	24.6	47.1	25.2	29.1	71.2	138.7
2015	22.3	69.3	27.8	53.3	28.0	32.9	78.1	150.5
2020	20.8	64.4	30.7	58.5	32.6	39.9	84.1	155.5
2025	20.7	64.1	34.0	65.0	38.8	49.5	93.4	167.9
2030	20.8	64.4	37.6	71.9	45.9	61.1	104.2	182.2

Incremental Exports versus 2008 (Thousands of Barrels per Day)

2010	-0.4	-1.0	-0.4	-0.6	-4.0	-5.1	-4.7	-10.6
2015	0.5	1.9	2.9	5.6	-1.2	-1.3	2.2	1.3
2020	-1.0	-3.0	5.7	10.9	3.4	5.7	8.1	6.3
2025	-1.1	-3.3	9.0	17.4	9.6	15.3	17.5	18.6
2030	-1.0	-3.0	12.6	24.2	16.7	26.9	28.3	32.9

Percent Change Compared to 2008

2010	-1.8%	-1.5%	-1.5%	-1.2%	-13.6%	-14.9%	-6.2%	-7.1%
2020	-4.5%	-4.5%	22.8%	22.8%	11.7%	16.8%	10.7%	4.2%
2030	-4.8%	-4.4%	50.4%	50.8%	57.3%	78.5%	37.2%	22.1%

Source: California Energy Commission analysis

The High Export Case from California assumes high fuel demand forecasts in Arizona and Nevada in conjunction with the East Line supplying barrels into Arizona preferentially over barrels being supplied from California through the West Line. Table 5.4 shows the estimated volume of pipeline exports originating from within California.

Table 5.4: Pipeline Exports to Arizona and Nevada From California – High Case

Historical & Forecast (Thousands of Barrels per Day)

	Gasoline		Diesel Fuel		Jet Fuel		Totals	
Year	AZ	NV	AZ	NV	AZ	NV	AZ	NV
2006	63.2	71.7	38.7	49.0	31.2	34.7	133.1	155.4
2007	50.3	70.9	30.0	47.7	32.4	35.2	112.7	153.8
2008	21.8	67.4	25.0	47.7	29.2	34.2	75.9	149.3
2010	21.5	66.6	25.7	49.1	25.2	29.1	72.3	141.0
2015	29.2	74.7	32.1	58.9	28.0	32.9	89.3	161.6
2020	34.7	76.1	35.6	62.7	32.6	39.9	102.8	171.4
2025	38.6	76.4	40.4	69.3	38.8	49.5	117.8	184.5
2030	58.9	84.9	51.9	80.4	45.9	61.1	156.7	211.2
Incremental Exports versus 2008 (Thousands of Barrels per Day)								
2010	-0.3	-0.8	0.7	1.5	-4.0	-5.1	-3.6	-8.3
2015	7.4	7.2	7.2	11.3	-1.2	-1.3	13.4	12.3
2020	12.9	8.7	10.6	15.0	3.4	5.7	26.9	22.1
2025	16.8	9.0	15.4	21.6	9.6	15.3	41.8	35.2
2030	37.1	17.4	26.9	32.7	16.7	26.9	80.7	61.9
Percent Change Compared to 2008								
2010	-1.5%	-1.2%	2.9%	3.1%	-13.6%	-14.9%	-4.7%	-5.6%
2020	59.0%	12.9%	42.5%	31.5%	11.7%	16.8%	35.4%	14.8%
2030	170.1%	25.9%	107.9%	68.7%	57.3%	78.5%	106.3%	41.4%

Source: California Energy Commission analysis

As indicated by the results in the above table, despite the RFS2 increased renewable requirement for gasoline, demand still increases over the forecast period. In part, this is caused by additional pipeline volumes of gasoline and diesel fuel shifting from the East Line to the West Line as pipeline capacity on the East Line is reached as soon as 2015. In fact, by 2030 an additional 41,000 barrels per day of supplies need to shift to the West Line to avoid exceeding maximum pumping capacity of the East Line system into Tucson and Phoenix.

The continued growth of transportation fuel demand in Arizona and Nevada could eclipse the capacity of some portions of the Kinder Morgan pipeline distribution system during the forecast period, absent additional expansions. Table 5.5 shows the estimated time frames whereby product pipeline capacities would be fully used under various scenarios. Most segments are not expected to exceed maximum pumping capacity over the forecast period due to the recent, significant drop in transportation fuel demand and lower demand outlooks linked to increased use of renewable fuels and improved fuel economy standards for motor vehicles.

Table 5.5: Product Pipelines – Maximum Capacity Timing

Pipeline Section From California	2009 Capacity TBD	Year that Maximum Capacity Of Pipeline is Reached	
		Low Case	High Case
Sacramento to Reno	45	Beyond 2030	2025
Colton to Las Vegas	156	2026	2021
Colton to Phoenix	204	Beyond 2030	Beyond 2030
Pipeline Section From Western Texas			
El Paso to Tucson	170	Beyond 2030	Beyond 2030
Tucson to Phoenix	155	Beyond 2030	Beyond 2030

Source: California Energy Commission analysis

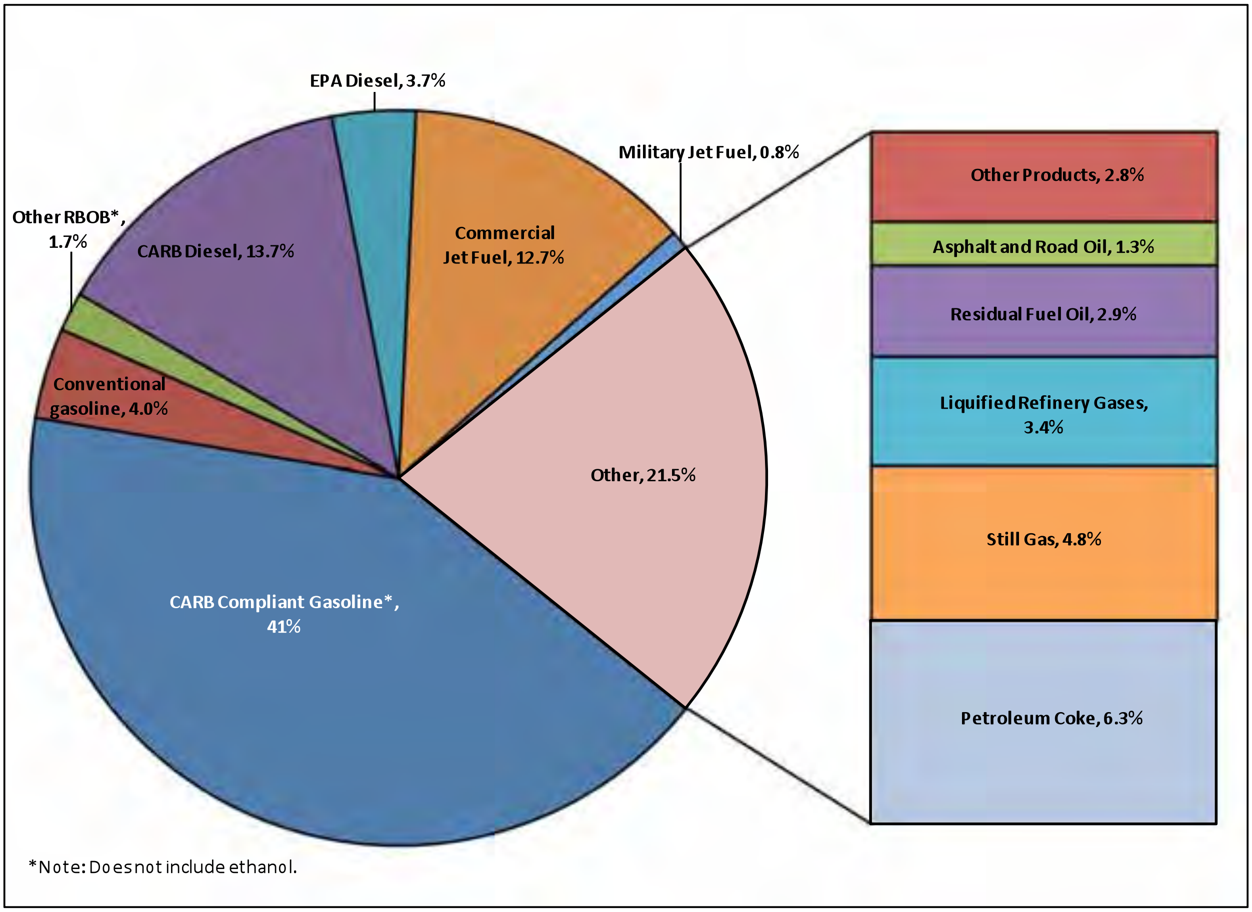
Based on these results of the export analysis, it appears as though there are no pipeline capacity constraint issues that appear imminent. Even if certain pipeline segments get close to capacity, it is assumed that Kinder Morgan will continue to invest capital to expand its distribution infrastructure to accommodate future demand growth.[clxv] If not, incremental demand for transportation fuels that exceed projected pipeline capacity would have to be supplied via tanker truck or rail car. This mode of transportation fuel delivery is far more expensive compared to pipeline shipments (approximately two to four times greater). As such, it is likely that additional expansions will continue to occur throughout the forecast period within the Kinder Morgan southwest system or through construction of another petroleum product pipeline system, such as the type of project proposed by Holly Energy Partners that is discussed in greater detail later in this chapter.[clxvi]

Transportation Fuel Import Forecast

The comparison of California's demand forecast with incremental production from refineries located in the state results in the forecast of transportation fuel imports. The incremental demand outlook includes incremental pipeline exports to Arizona and Nevada. The difference between the regional demand growth for transportation fuels and additional refinery output of refined products is a forecast of incremental imports for gasoline, diesel, and jet fuel for 2015, 2020, and 2025.

California refinery production is forecast to continue growing on an incremental basis for the Low Import Case scenario only. This refinery creep of crude oil distillation capacity will yield additional refinery blendstocks that will be converted to transportation fuels for use in California and for export to neighboring states and other locations. Staff assumed that the proportion of transportation fuels produced by processing additional quantities of crude oil will be similar to the ratios that were observed during 2008. Figure 5.3 depicts the percentage of various transportation fuel types that were produced in 2008 for each barrel of crude oil processed.

Figure 5.3: California Refinery Output in 2008 by Product Type



Source: PIIRA data and California Energy Commission analysis

Applying this ratio of transportation fuel output to the incremental crude oil that is processed, the supply of gasoline, diesel, and jet fuel produced from California refineries increased by a range of 69,000 to over 135,000 barrels per day. Table 5.6 lays out the incremental production by each type of transportation fuel over the forecast period, assuming refiners continue to gradually process ever larger quantities of crude oil each year under the Low Import Case scenario.

Table 5.6: California Incremental Refinery Production

(Thousands of Barrels per Day)

	Low Import Case			High Import Case		
Transportation Fuel	2015	2020	2025	2015	2020	2025
California Gasoline	36.4	55.7	71.5	0.0	0.0	0.0
Export Gasoline	5.0	7.6	9.8	0.0	0.0	0.0
California Diesel Fuel	12.6	19.3	24.8	0.0	0.0	0.0
EPA Diesel Fuel	3.4	5.2	6.6	0.0	0.0	0.0
Jet Fuel	11.6	17.8	22.8	0.0	0.0	0.0
Totals	69.0	105.6	135.4	0.0	0.0	0.0

Source: California Energy Commission analysis

Under the High Import Case analysis (See Table 5.7.), California net imports of gasoline are forecast to decrease significantly over the next 15 years, while imports of diesel and jet fuel would need to rise to keep pace with growing demand for those products. Under the Low Import Case scenario, the growing imbalance for gasoline increases and the incremental imports for other transportation fuels are lessened, resulting in a net decline of total imports of nearly 100 thousand barrels per day by 2025.

Table 5.7: California Incremental Imports of Transportation Fuels

Net Change (Thousands of Barrels per Day)

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	-3.0	-138.8	-218.4	98.5	9.4	-50.8
Diesel Fuel	-65.9	-51.8	-21.7	14.0	-21.5	19.7	68.2
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	-43.3	-114.9	-116.1	106.1	106.8	154.2

Reduced Imports of Gasoline Blendstocks

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	***50.8***	***-85.0***	***-164.6***	51.3	***9.4***	***3.0***
Diesel Fuel	-65.9	-51.8	-21.7	14.0	-33.6	-8.0	20.0
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	10.5	-61.1	-62.3	46.8	79.2	159.8
Gasoline Blendstocks	53.8	0.0	0.0	0.0	53.8	0.0	0.0

Reduced Receipts of Unfinished Refinery Feedstocks

		Low Import Case			High Import Case		
Transportation Fuel	2008	2015	2020	2025	2015	2020	2025
Gasoline	51.3	***0.0***	***68.9***	***-10.7***	43.3	***0.0***	***0.0***
Diesel Fuel	-65.9	***-43.2***	***-12.1***	***23.6***	-33.6	-8.0	***20.7***
Jet Fuel	-6.9	11.5	45.6	88.3	29.1	77.7	136.8
Totals	-21.6	-31.7	102.4	101.2	38.9	69.7	157.6
Gasoline Blendstocks	53.8	0.0	0.0	0.0	53.8	34.5	0.0
Refinery Feedstocks	192.3	19.8	0.0	0.0	192.3	192.3	176.8

Source: California Energy Commission analysis

This type of initial outcome is unlikely to materialize as refiners will adjust operations to decrease the ratio of gasoline components that are produced for each barrel of crude oil processed. One such example is for refiners to eliminate the imports of gasoline blending components so that production is lower, thus reducing the imbalance for gasoline over the forecast period. Another example of refinery operational changes is to reduce the quantity of unfinished gas oils used as a feedstock for certain refinery process equipment. This approach can further reduce the gasoline imbalance over the next couple of decades. These two examples of refinery operational changes would not alter the quantity of crude oil being processed at the refineries. As such, refiners may also need to reduce the quantity of crude oil processed at the refineries by lowering the utilization rates or closing some portion of the state's refining capacity. The potential trend of declining gasoline demand in conjunction with rising diesel fuel demand is something to which the European refining market has evolved over several years. That situation has resulted in large excess supplies of gasoline that require export outside Europe and a growing shortfall of local refinery distillate production that must be imported from outside the region.

Marine Vessels–Incremental Voyages

The increased imports (or exports as the case may be) of transportation fuels is expected to result in a greater number of marine vessels (referred to as product tankers) using California marine terminals. Staff has examined recent import information to determine an average cargo size per product tanker import or export event. Petroleum tankers are constructed with multiple compartments that enable the transport of more than one type of petroleum product per voyage. In addition, some product tankers will discharge or load cargoes at more than one marine terminal. Finally, staff recognizes that there are instances where transportation fuels are imported or exported via ocean-going barges that have smaller cargo capacities when compared to typical product tankers.

For calculating additional product tanker trips, staff used an upper limit of 300,000 barrels of cargo capacity per import or export event and a lower limit of 150,000 barrels capacity. The upper limit is an average of the largest product tankers (top 25 percent) that were involved in a foreign import of transportation fuels in 2008. The lower range was estimated by using the average size of all of the foreign product tanker vessels for 2008. It is assumed that the bulk of the incremental imports or exports of transportation fuels will either originate from foreign sources (for imports) or be transported to foreign destinations (for exports). Using these two estimates for product tanker capacity, staff calculated the incremental number of import and export events that could be required over the forecast period (see Table 5.8).

Table 5.8: Annual California Incremental Product Tanker Visits

	Low Import Case			High Import Case		
Marine Vessel Size	2015	2020	2025	2015	2020	2025
150,000 Barrels	-53	-227	-230	258	260	375
300,000 Barrels	-26	-114	-115	129	130	188

Source: California Energy Commission analysis

The negative numbers in the above table are actually incremental export events that could occur if a large imbalance develops between growing California refining production and shrinking gasoline demand created by the RFS2 mandates. As stated earlier, this scenario is unlikely to develop without changes in operation of the existing refineries.

Additional Factors With Potential for Impact

A number of near-term factors could increase the uncertainty of the transportation fuels import forecast, namely: new expansion projects for California refineries; level or reduced capacity for processing crude oil; and construction of a new petroleum product pipeline to one of the neighboring states from a supply source located outside California.

California Refinery Expansion

There are no refinery expansion projects examined as alternative scenarios during this IEPR cycle. Although two refinery projects have been closely monitored by staff over the last year, neither of these proposed refinery production expansions is deemed likely over the near term, and both have been excluded from alternative scenario assessment.

The Chevron Energy and Hydrogen Renewal Project at its Richmond refinery initially involved the replacement of two catalytic reformer reactors with a single continuous catalyst regeneration (CCR) refinery process unit.[clxvii] This portion of the project would have increased the production of gasoline by approximately 300,000 gallons per day or about 7,140 barrels per day.[clxviii] However, Chevron has recently decided that the CCR portion of the project "will be indefinitely delayed due to a combination of factors, including weakened demand for product and higher construction costs and a tough economic environment following a rather lengthy permitting process."[clxix]

The other proposed refinery project being monitored by staff is the production capacity expansion for gasoline and diesel fuel associated with the Big West refinery in Bakersfield. The Clean Fuels Project (CFP) is designed to convert partially processed crude oil (gas oils) that is normally exported from the refinery into approximately 1.3 million gallons per day of transportation fuels (about 20,000 barrels per day of diesel fuel and up to 10,000 barrels per day of gasoline).[clxx] However, the parent company for Big West of California, Flying J, filed for Chapter 11 protection December 22, 2008.[clxxi] As of this writing, the Bakersfield refinery is idled. Staff assumes that the refinery will resume operations at normal rates by January 2011, at the latest. Flying J announced on February 2, 2010, that it has "entered into an Asset Purchase Agreement with Paramount Petroleum Corporation" to sell the refinery to Paramount Petroleum.[clxxii] Due to the inactive status of the facility and the uncertainty associated with significant funding for the proposed refinery expansion work, this additional quantity of refined product output associated with the CFP was not included as part of any alternative scenarios.

No Growth of California Refinery Distillation Capacity

Over time, the capacity of California refineries to process crude oil has gradually increased. Staff has assumed that this continual refinery creep will continue as part of the base assumptions used in the primary analysis of imports and exports of refined transportation fuels. However, if the assumption is changed to one whereby the distillation capacity of the California refineries remains fixed over the forecast period, the quantity of imported transportation fuels will be greater, and the amount of crude oil imported will be lower than the information presented under the Low and High demand scenarios. Table 5.9 shows that the exports of transportation fuels could be more than 100 TBD less by 2020 under the Low Import Case.

New Petroleum Product Pipeline Project

As described earlier in this chapter, California is an important source of transportation fuels for Nevada and Arizona. These fuels are primarily delivered to these neighboring states via petroleum product pipelines operated by Kinder Morgan. Periodically, proposed pipeline projects are announced that are designed to provide new sources of supply to these adjacent states from supply regions outside California. If such a pipeline project were to be constructed, these additional supplies would compete with existing sources and could diminish the forecasted demand for petroleum product pipeline exports to Nevada and / or Arizona.

Holly Energy Partners and Sinclair Oil have partnered in a planned project to construct the 406-mile UNEV petroleum product pipeline that originates in Utah and terminates in northern Las Vegas. The pipeline will provide transportation fuels to the Las Vegas market from refineries located in the Salt Lake City area. Construction on the terminal in Cedar City, Utah, has already commenced, and the pipeline work was scheduled to begin by early 2010.[clxxiii] The pipeline could become operational as early as the fall of 2010 with an initial pumping capacity of 62,000 BPD. Over time, the pipeline system could be expanded to a maximum pumping capacity of up to 118,000 BPD.[clxxiv]

An alternative scenario examined for this chapter involves the potential impact on the pipeline export forecast into southern Nevada that could occur as a result of the UNEV pipeline project being built and delivering transportation fuels into Las Vegas. The 62,000 BPD UNEV capacity was examined in conjunction with both the High and Low Demand Cases for Nevada to quantify the potential impact on California pipeline exports to southern Nevada. However, it is unclear at this point what quantity of spare refinery production capacity in the Utah region may be available to provide excess supply to the UNEV pipeline. It is possible that the pipeline will not initially operate at full capacity when construction is completed.

Results of this scenario are presented in Table 5.9. Under the Low Import Case, pipeline exports to Las Vegas from points originating in California could be reduced by up to 62 TBD by 2015. This scenario could displace approximately 50 percent of the forecasted pipeline deliveries to Las Vegas from California by this time. Under the High Import Case, operation of the UNEV pipeline could displace up to 83 percent of the forecasted California-sourced deliveries by 2020, assuming the new pipeline operates at the higher capacity of 118 TBD by that time. The UNEV pipeline project has the potential to reduce export demand on California refineries and marine import infrastructure, as well as improve supply redundancy options for the Las Vegas markets during periods of temporary interruption of petroleum product pipeline operations.

California Renewable Fuel Demand, Production, and Imports

California ethanol demand is forecast to increase primarily from federal and state mandates that are discussed at length in Chapter 3 of this report. It is unclear the exact nature of the infrastructure necessary to handle the increased quantity of ethanol anticipated over the near and mid-term period. The LCFS is likely to greatly complicate planning for the necessary logistics and supply modifications.

Summary of Transportation Fuel Import Forecast

The following Table 5.9 contains the incremental import forecast of transportation fuels for the Low and High Cases in 2015, 2020, and 2025. The table also displays the summary of the effects on incremental imports (or exports for negative numbers) that could be assumed based on the additional factors examined regarding refinery operations and new pipeline projects. The most striking implication is that the large export imbalance for the Low Case is almost completely offset to a near balance level if no refinery creep is assumed for this scenario.

Table 5.9: Summary of Import Forecast and Additional Factors

Incremental Imports of Transportation Fuels (Thousands of BPD)

	Low Case			High Case		
	2015	2020	2025	2015	2020	2025
Transportation Fuels Forecast Results	-43.3	-114.9	-116.1	106.1	106.8	154.2
Refinery Projects and Operations						
New UNEV Pipeline (CalNev Line Only)	-105.3	-176.9	-234.1	44.1	44.8	36.2
No California Refinery Creep	25.7	-9.3	19.3	106.1	106.8	154.2

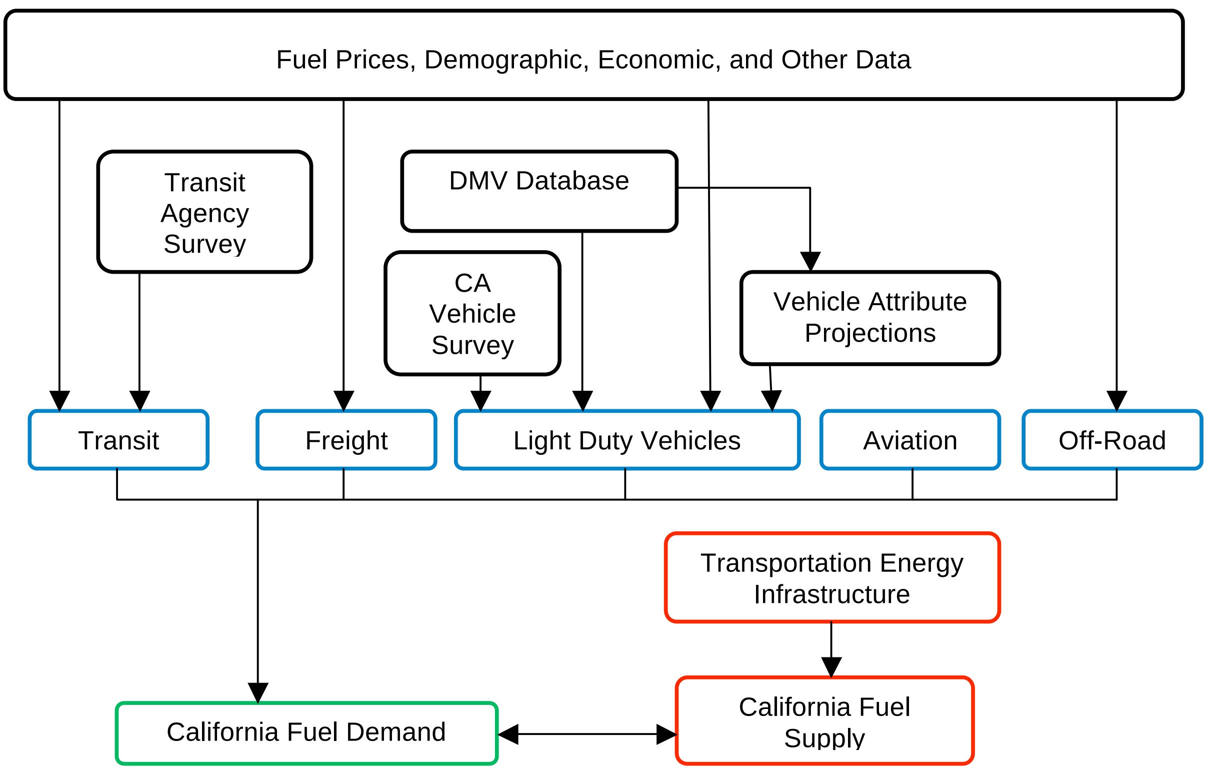
Source: California Energy Commission analysis

APPENDIX A

TRANSPORTATION FUEL DEMAND FORECASTING METHODS

The transportation fuel demand forecasting methods closely follow those described in the *2007 IEPR*. However, various inputs and assumptions to the models have been updated. In some cases, the models have been changed or updated, but the forecasting methods have remained consistent with previous forecasts. Figure A.1 illustrates the flow of data through the demand models and related analyses.

Figure A.1: Transportation Energy Data Flow Diagram



Source: California Energy Commission

Light-Duty Vehicle Fuel Demand Model

The current model was patterned after the Energy Commission's Personal Vehicle Demand Model developed in 1983. The California Light Duty Vehicle Conventional and Alternative Fuel Response Simulator or CALCARS model is a personal light-duty vehicle forecasting methodology that projects number and type of vehicles owned, along with annual vehicle miles traveled (VMT) and fuel consumption by personal cars and light-duty trucks in California.[clxxv] CALCARS model was designed to evaluate impacts of public policy on overall light-duty vehicle fuel use, promote (or make easier) the development of strategies to reduce California's dependence on petroleum, and help promote alternative fuels and alternative fuel vehicles.

CALCARS is a discrete vehicle choice model that is used to forecast California light-duty vehicle ownership, VMT, and light-duty vehicle fuel demand by simulating vehicle purchase decisions and fuel use by California motorists. These forecasts are based on projections of California demographic and economic trends, fuel prices, vehicle attributes, and current consumer preferences for light-duty vehicles.

Over the past two decades, the CALCARS model has been updated with new information several times, in 1996 and for the *2003*, *2005*, *2007* and current *IEPRs*. The detailed information integrates demographic and economic data with preference data to evaluate consumer vehicle choices. The 2009 updates include:

- Consumer preferences from the Energy Commission 2008 California Vehicle Survey.
- Forecasts of transportation fuel prices in California.
- 2007 DMV registered on-road vehicles counts.
- Forecasts of light-duty vehicle fuel economy and attributes.
- New fuel and vehicle types.
- Forecasts of light-duty vehicle fuel economy and attributes.
- Forecasts of California demographic data.
- Forecasts of California economic growth.

As a discrete choice model, CALCARS requires the collection of data on consumer preferences from a representative sample of Californians and vehicle characteristics, such as operating cost and vehicle price. The 2008 California Vehicle Survey collected stated preference data from 3274 residential households and 1780 commercial vehicle owners in California and used this data to estimate and update the CALCARS model. A total of 105 classes of vehicles and 17 model years was incorporated into the model using the 2008 California Vehicle Survey.

California Freight Energy Demand (Freight) Model

The Freight Model was developed in 1983 to forecast demand for truck and rail freight transportation fuels. The Freight Model projects volumes of freight transported by truck and rail, truck stock, and VMT, along with truck and rail consumption of gasoline, diesel, and LPG for five California regions. These outputs are driven by projections of economic activity in 16 economic sectors and fuel cost projections. The Freight Model analyzes rail and truck mode choices, as well as truck type choices, and produces detailed projections of activity and fuel consumption within California for all trucks and rail-freight operations. The model also analyzes public policy by measuring the impact of fuel prices and other costs on vehicle choice, fuel choice, mode choice, and fuel economy.

The Freight Model was updated in 1998 but reflects energy markets and regulatory environments that have changed substantially since the early 1980s. The 1998 improvements include a new modal diversion model, as well as adding new data on freight operation cost and fuel efficiency and updating other data for average truck payloads, rail carloads, and truck survival rates.

California Transit Energy Demand (Transit) Model

The Transit Model is a discrete choice travel demand model that was developed in 1983 to produce long-term forecasts of travel demand and energy consumption by urban bus and rail transit systems, intercity bus and rail, school buses, and other buses operating in California. The model estimates the effects of changes in transit fares, service policies, automobile fuel economy, gasoline prices, population, employment, and income on transit energy consumption. As a travel demand model, it is also capable of estimating the effectiveness of policies designed to save energy by promoting trip diversions from automobile to transit mode.

The original model included 16 transit agencies in California, mostly from the Bay Area and Southern California. As part of the ongoing effort to update input data and collect current information about transit agencies, the staff has surveyed additional transit agencies to expand the data set and generate forecasts for 64 transit agencies and incorporate expanded service areas and transit fuel types. Population, income, fuel prices, and other data have been updated to accommodate the 2006-2007 fiscal year, the last year with complete data, as the base year for forecasting.

California Civil Aviation Jet Fuel Demand (Aviation) Model

The commercial aviation demand for jet fuel is derived from demand for passenger air travel and air freight transportation. Staff separated these sectors by differentiating airlines that only transport freight from airlines whose primary activity is transporting passengers, but some of which transport freight as well. While this will leave some freight in the passenger aviation model, these airlines are still primarily driven by passenger demand. Passenger aviation fuel demand model uses income, employment, aviation fuel prices, and passenger plane-specific fuel economy projections to forecast passenger miles and jet fuel demand for passenger air transportation. Freight aviation fuel demand model uses freight cargo-specific fuel economy and the economic projections to forecast freight ton miles and jet fuel demand for air freight. Staff derived two fuel economy projections from FAA data. One fuel economy scenario was based on the assumption that the aviation industry will meet the FAA's goal of improving fuel economy by 1 percent for every forecast year. The second fuel economy scenario was based on the fuel economy improvements imputed from FAA forecasts and holding it constant between 2025 and 2030. These alternative fuel economy scenarios were combined with two price scenarios to form four aviation fuel demand cases.

Other Transportation Fuel Sectors

Off-road diesel is defined in this report as diesel used in California that is for non-highway use. Some off-road uses of diesel are for transportation, such as agriculture, construction, ocean-going vessels, and inland watercrafts. Other off-road uses of diesel include portable electric generation, heating, and the like. Historical information regarding this component of diesel demand indicates that agriculture and construction sectors are the largest users of off-road diesel. The *2009 IEPR* continued the use of the *2007 IEPR* growth rate assumptions. Further work in modeling this sector is expected to occur for the *2011 IEPR*.

Although some diesel is used in marine applications, ocean going vessels primarily use residual fuel oil, for which staff has produced no demand forecast in this report.

Land Use and Personal Vehicle Miles Traveled Demand

Increasing attention to the relation between land use and transportation demand has prompted the growing efforts in land use and transportation model integration. The models staff has used to forecast fuel demand did not include a land-use model, but indicators of land use are incorporated in the model. Residential VMT is estimated with a single equation, which complements the residential vehicle choice model. This residential VMT equation accounts for the significant impact of miles-to-work on the miles traveled. Additionally, as a standard travel demand model, the transit model incorporates travel time, which accounts for some travel-related land-use characteristics.

APPENDIX B

CALIFORNIA TRANSPORTATION FUEL PRICE FORECASTS

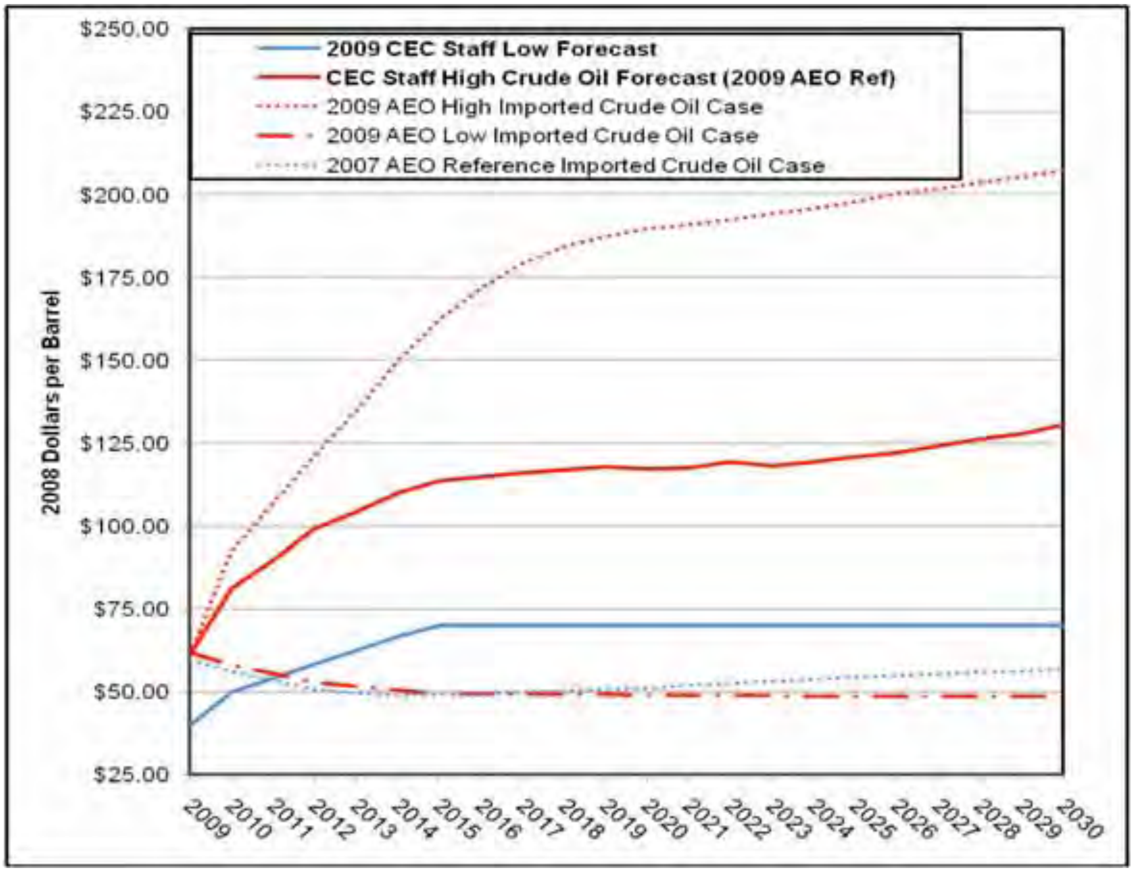
Summary

Staff has developed High and Low Crude Oil Price Case forecasts for California transportation fuels based on the U.S. EIA *2009 Annual Energy Outlook* Reference Case and Energy Commission Low Case oil price forecasts, respectively. The Energy Commission's High Case starts at $2.90 per gallon for gasoline and $3.09 for diesel in 2009, jumps to $4.36 and $4.43, respectively, in 2015, and then continues to rise to $4.80 and $4.87 by 2030 (all prices are in 2008 dollars, to adjust for inflation).[clxxvi] Energy Commission Low Case price forecasts start at $2.34 for gasoline and $2.42 for diesel per gallon in 2009, climb to $3.17 and $3.19, respectively, in 2015, and then hold constant until 2030. Staff has also prepared price forecasts for other transportation fuels, including railroad diesel, jet fuel, E-85, biodiesel, electricity, compressed natural gas, liquefied natural gas, propane, and hydrogen, that are discussed later in this appendix.

Crude Oil Price Forecast Assumptions

Staff has based California-specific High and Low Case regular-grade gasoline and diesel price forecasts on crude oil price forecasts. The United States refiner acquisition cost (RAC) of imported crude oil, as defined and measured by U.S. EIA, is used as a proxy for crude oil prices. This index is the average price of all imported crude oil and is roughly $5 to $7 per barrel less than the index for higher-quality imported light sweet oil.[clxxvii] The High Crude Oil Price Case forecast is based on the U.S. EIA *2009 AEO* Reference Case. The Low Crude Oil Price Case forecast is an Energy Commission staff estimate approximating alternative crude oil price forecasts from other organizations identified by the *2009 AEO*. Figure B-1 compares the 2009 Energy Commission staff and various U.S. EIA crude oil price forecasts.[clxxviii]

Figure B.1: Comparison of Energy Commission 2009 Staff Crude Oil Price Forecasts With EIA *2007* and *2009 AEO* Forecasts (in 2008 Dollars)



Source: U.S. Energy Information Administration – *Annual Energy Outlook* (*AEO*) and California Energy Commission

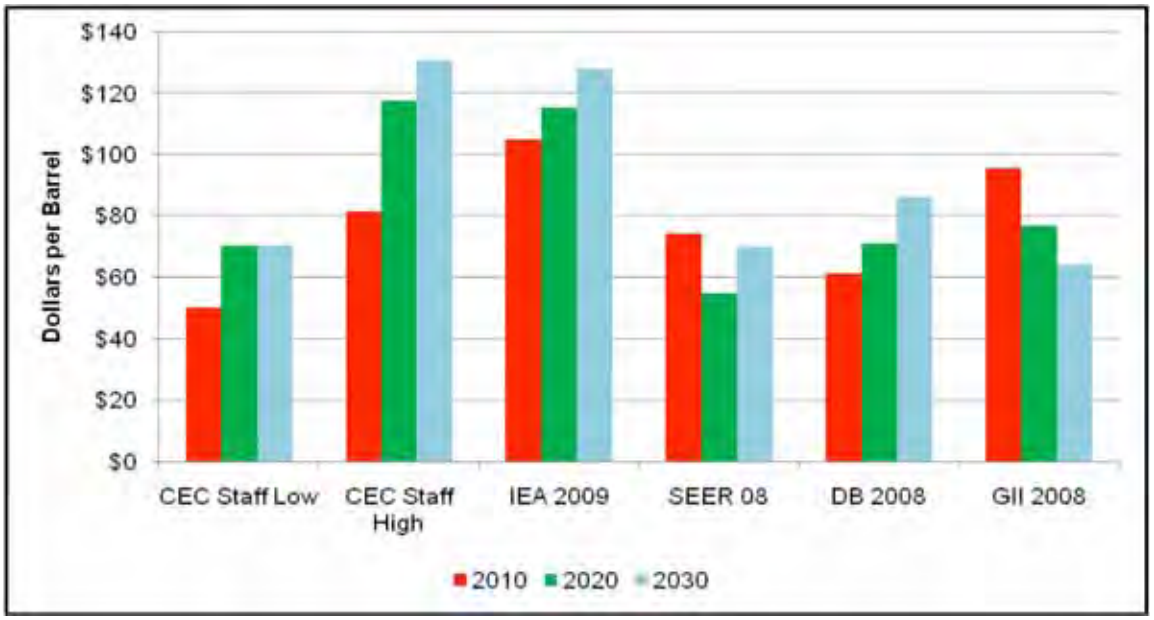
Table B.1 shows the Energy Commission crude oil price forecast cases, and Figure B.2 compares the Energy Commission low and high crude oil price forecasts with crude oil price forecasts by other well-known forecasters in the field.

Table B.1: Energy Commission 2009 Staff Crude Oil Price Forecast Cases (real and nominal dollars per barrel)

	Energy Commission Staff High Crude Oil Price Case [AEO 2009 Reference Case]		Energy Commission Staff Low Crude Oil Price Case	
Year	2008$	Nominal	2008$	Nominal
2009	$61.49	$61.94	$40.09	$40.38
2010	$81.37	$82.09	$49.96	$50.40
2011	$89.77	$91.83	$54.14	$55.38
2012	$99.49	$103.56	$58.31	$60.69
2013	$104.64	$110.85	$62.48	$66.19
2014	$110.11	$118.45	$66.65	$71.71
2015	$113.85	$124.48	$70.00	$76.53
2016	$115.15	$128.03	$70.00	$77.83
2017	$116.16	$131.33	$70.00	$79.14
2018	$117.05	$134.56	$70.00	$80.47
2019	$118.02	$137.94	$70.00	$81.81
2020	$117.54	$139.65	$70.00	$83.17
2021	$117.83	$142.32	$70.00	$84.55
2022	$119.69	$146.96	$70.00	$85.95
2023	$118.50	$147.88	$70.00	$87.36
2024	$119.62	$151.74	$70.00	$88.79
2025	$120.98	$155.92	$70.00	$90.22
2026	$122.20	$160.00	$70.00	$91.65
2027	$124.47	$165.53	$70.00	$93.09
2028	$126.62	$171.00	$70.00	$94.54
2029	$127.95	$175.47	$70.00	$96.00
2030	$130.71	$181.98	$70.00	$97.46

Sources: U.S. Energy Information Administration and the California Energy Commission

Figure B.2: Energy Commission and Other Crude Oil Price Forecasts (in 2008 Dollars)



Sources: U.S. Energy Information Administration and the California Energy Commission

* Energy Commission staff crude oil high price case is the same as the 2009 AEO reference price case.

** GII = Global Insight, IEA = International Energy Agency, DB = Deutsche Bank, SEER = Strategic Energy and Economic Research

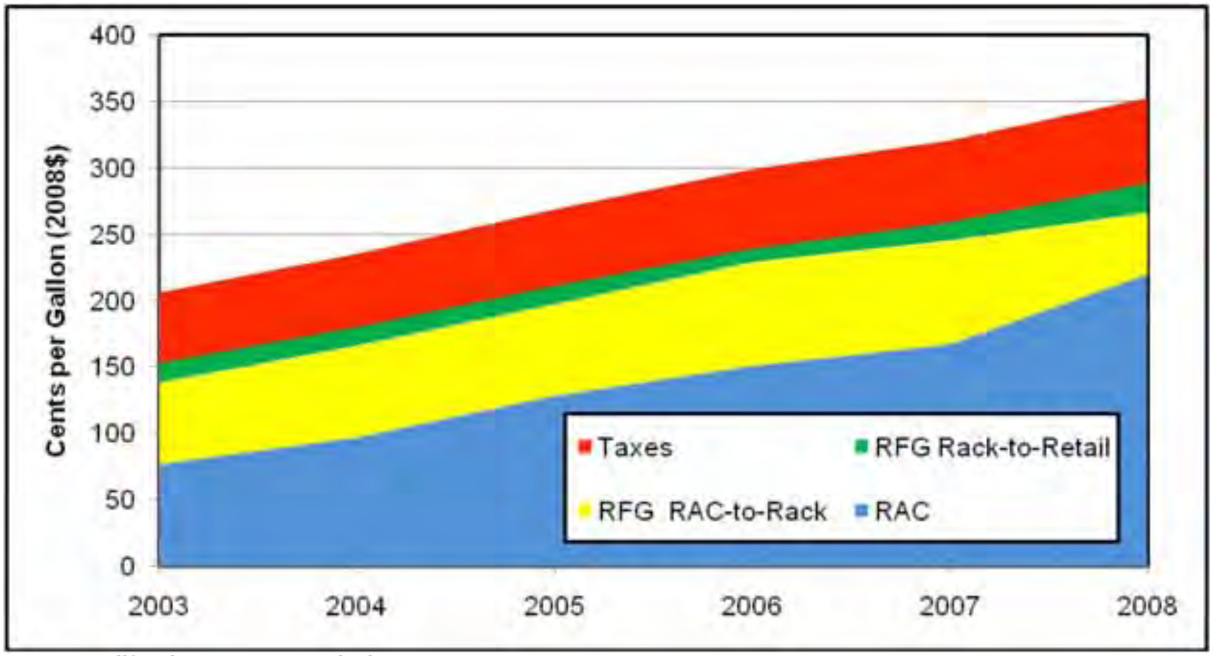
Petroleum Transportation Fuel Price Forecast Assumptions

Staff established relationships between wholesale fuel and crude oil prices using monthly crude oil price data from the EIA and average monthly California rack prices for gasoline and diesel from the Oil Price Information Service (OPIS). The January 2003 to December 2008 period was used in deriving the price margins because during this time MTBE-free reformulated gasoline was the dominant gasoline refined and used in the state.

The difference between monthly RAC crude oil price and the OPIS California average monthly gasoline and diesel rack prices is referred to as the “crude oil to rack price” margin. This margin varies over time on a monthly basis, and the decision to use one period’s historical margin over another’s can make a difference in the final retail fuel price forecast.

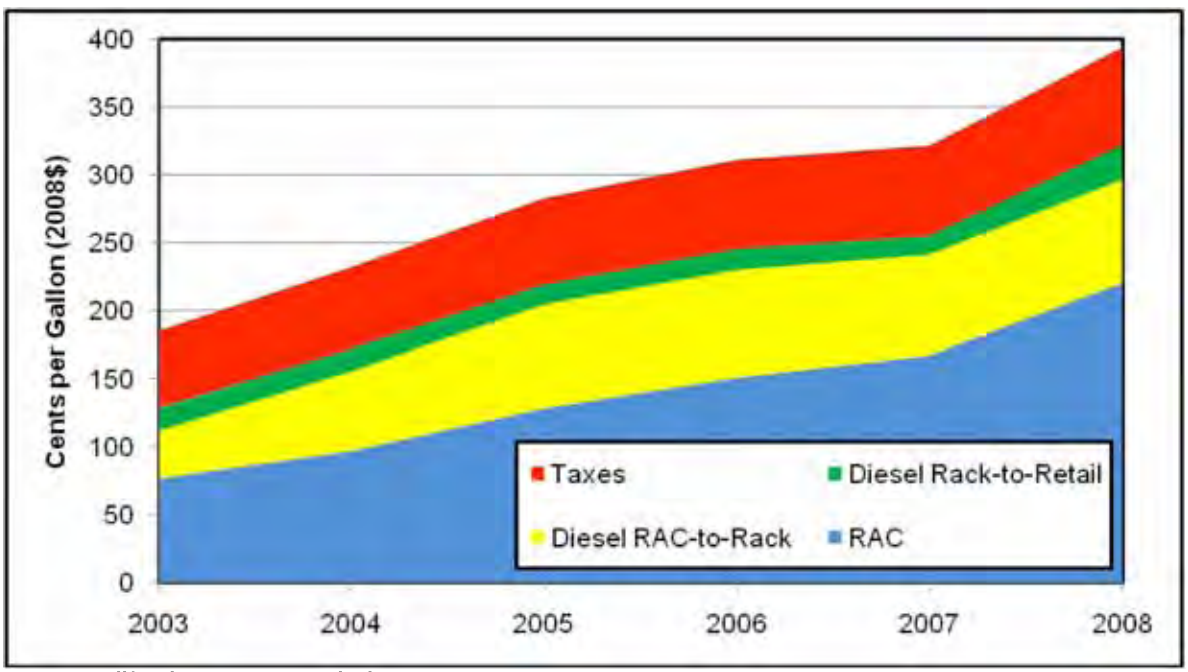
The next step was to determine the “rack to retail price” margin, as the historical differences between the weekly OPIS rack price and the weekly U.S. EIA retail price series (excluding taxes) for both California regular-grade gasoline and diesel. Again, the decision to choose one period’s margin as representative of future expectations will affect the final retail price forecast. Figures B.3 and B.4 illustrate the components of the retail prices paid by the consumers at the pump for gasoline and diesel, including RAC crude oil prices, annual averages of both “crude oil to rack price” and “rack to retail price” margins, and taxes.

Figure B.3: California Retail Gas Price Components 2003 – 2008 (in 2008 Dollars)



Source: California Energy Commission

Figure B.4: California Retail Diesel Price Components 2003 – 2008 (in 2008 Dollars)



Source: California Energy Commission

Table B.2 summarizes the crude oil to rack price margins and the rack to retail ex-tax margins that are used with the two crude oil price cases, in forecasting gasoline and diesel prices. All prices are in 2008 CPG, and they represent annual averages of the monthly prices, in all cases.

The High Price Case margins (for both gasoline and diesel) were based on years of higher combined margins (2006–2008 data) and the Low Price Case margins, on lower levels (2003–08 data).

Table B.2: Margins Used in RFG and Diesel Price Forecast Cases (2008 cents per gallon)

Energy Commission Crude Price Case	Crude-to-Rack		Rack-to-Retail	
	RFG	Diesel	RFG	Diesel
Energy Commission High Price	67.2	76.7	15.5	18.1
Energy Commission Low Price	66.7	66.9	14.9	16.9

Source: California Energy Commission

In 2007, ARB adopted a regulation to require 10 percent ethanol content in gasoline formulation, which Energy Commission staff expects to raise the price of gasoline. Adders were estimated for the gasoline price forecast to reflect these changes. In the Low Case 5 cents per gallon were added, and in the High Case 10 cents per gallon were added starting in 2012. For the early adoption years of 2010 and 2011, these values were 2.5 cents per gallon in the Low Case and 5 cents per gallon in the High Case.

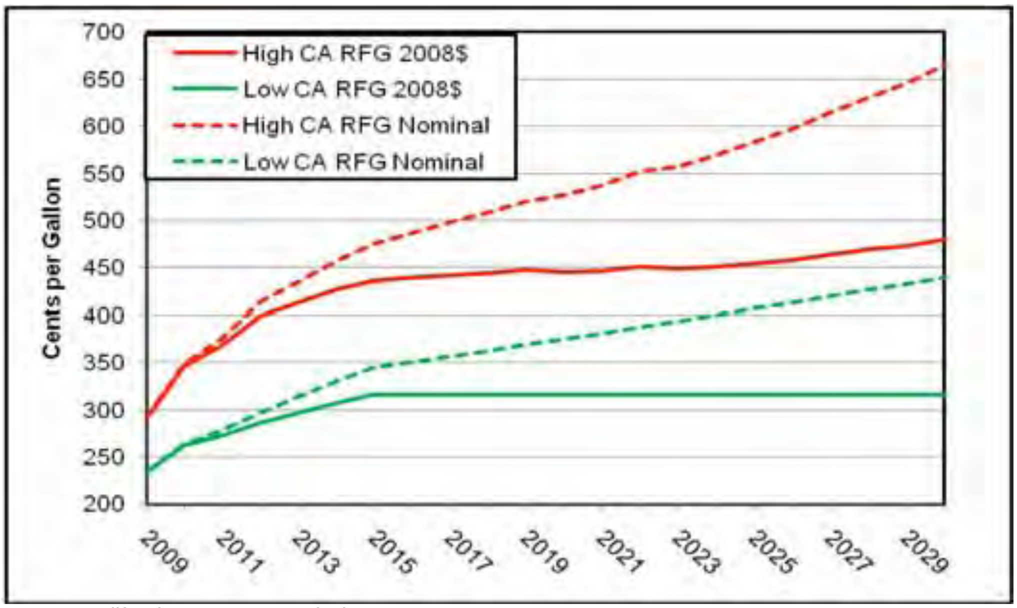
The last step in generating a final retail price forecast for each of the fuels is to add excise and sales taxes and fees. In the case of regular-grade gasoline, combined federal and state excise taxes (including fuel use and underground storage tank levies) totaled $0.378, and sales tax was estimated at 8 percent. For diesel, the federal excise taxes add up to $0.244, and the state excise taxes add up to $0.194. In the case of diesel, however, $0.18 of the state excise tax was included after sales tax was calculated over the remainder of the costs, as that portion is exempt from sales taxation.

Using the previously described diesel fuel crude-to-rack price margins and crude oil price forecasts, staff developed railroad diesel and jet fuel High and Low Price Case forecasts for the 2009-2030 period. Excise tax of $0.069 per gallon and California sales tax of 8 percent are added to the wholesale diesel fuel price to generate the final railroad diesel price forecast estimates. California sales tax of 8 percent does not apply to certified commercial air carriers and therefore is excluded from the final jet fuel price forecasts. However, a $0.044 per gallon excise tax and a distribution adder equal to half the corresponding diesel rack-to-retail margin are added to the wholesale diesel fuel price to generate the final jet fuel price forecast.

California Petroleum Fuel Price Forecasts

Figure B.5 illustrates the annual average gasoline price projections in both real and nominal 2008 dollars using the assumptions described above. Nominal prices represent the average prices customers would actually see at the pump during that year.

Figure B.5: California Gasoline Price Forecasts (real and nominal cents per gallon)



Source: California Energy Commission

Table B.3 shows the annual average retail fuel price projections for regular-grade California gasoline, California diesel, California railroad diesel, and California jet fuel in 2008 dollars using the assumptions outlined above.

Table B.3: California Retail Petroleum Transportation Fuel Price Forecasts (2008 cents per gallon)

	High Crude Oil Price Forecast				Low Crude Oil Price Forecast			
	RFG	Diesel	Railroad Diesel	Jet Fuel	RFG	Diesel	Railroad Diesel	Jet Fuel
2009	290	309	249	237	234	242	183	176
2010	347	360	300	284	262	267	209	200
2011	369	381	322	304	273	278	219	209
2012	399	406	347	327	287	289	230	219
2013	413	420	360	340	297	299	241	229
2014	427	434	374	353	308	310	251	239
2015	436	443	383	361	317	319	260	247
2016	440	447	387	365	317	319	260	247
2017	442	449	389	367	317	319	260	247
2018	444	452	392	369	317	319	260	247
2019	447	454	394	371	317	319	260	247
2020	446	453	393	370	317	319	260	247
2021	446	454	394	371	317	319	260	247
2022	451	458	398	375	317	319	260	247
2023	448	455	395	373	317	319	260	247
2024	451	458	398	375	317	319	260	247
2025	455	462	402	378	317	319	260	247
2026	458	465	405	381	317	319	260	247
2027	464	471	411	387	317	319	260	247
2028	469	476	416	392	317	319	260	247
2029	472	480	420	395	317	319	260	247
2030	480	487	427	402	317	319	260	247

Source: California Energy Commission

Alternative Transportation Fuel Price Forecasts

For the *2009 IEPR* cycle, staff has expanded the list of transportation fuel price forecasts to include the following: E85, B20, transportation electricity rates, CNG, LNG, hydrogen, and propane. These price forecasts are inputs to the vehicle manufacturer offerings forecasts and fuel demand forecasts. It should be noted that the formulation and implementation of current and potential future policies add to the uncertainty in forecasting the prices for these alternative transportation fuels. High and low price forecasts were developed after consultation with the other offices within the Energy Commission regarding all of these fuel types.

Propane and Renewable Fuel

High and low price projections for E85, B20, and propane for transportation use, are based on the corresponding high and low RAC price forecasts used by gasoline and diesel fuels. The E85 price bands are based on E85 being priced on a gasoline gallon equivalency, thus making it the same price as gasoline on an energy content basis.

In the case of biodiesel, analysis of B20 wholesale prices yields an average 52.9 cent difference between diesel rack and B20 rack prices in 2008. Due to the limited amount of information regarding B20 prices under different market conditions, the same 52.9 cent margin was applied at the rack level to both high and low B20 forecasts. High and Low diesel rack-to-retail margins were then applied along with taxes to obtain the final price forecast.

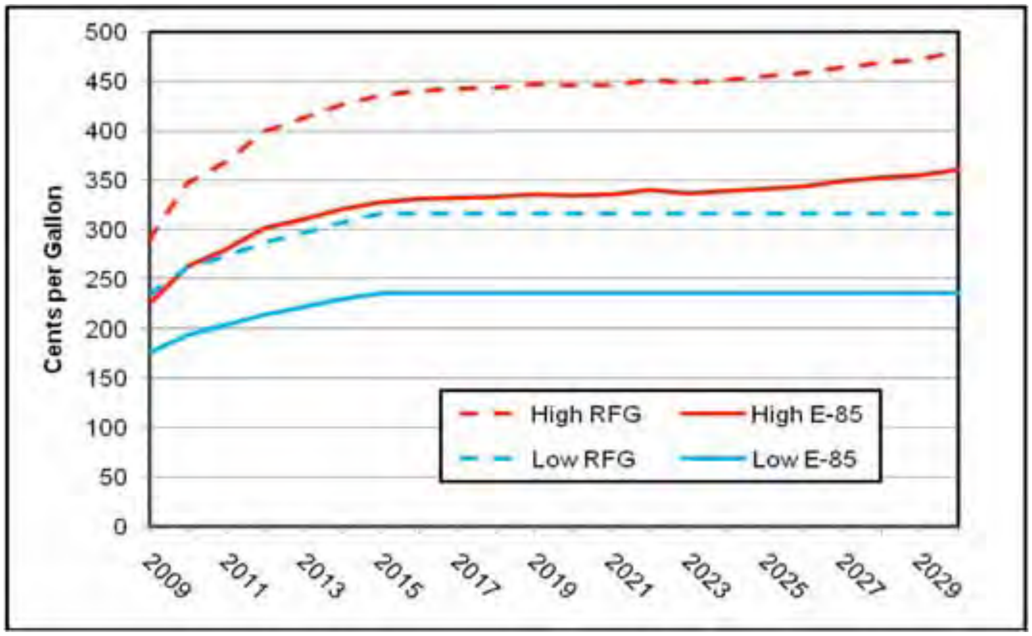
Transportation propane prices were projected based on an assumed wholesale propane price link with RAC. From 2000 to 2008, the wholesale propane prices averaged to 91 percent of RAC. This ratio was applied to the high crude oil price forecast to develop the high wholesale propane price forecast. Staff used a similar method to develop the low price forecast but based this on the 2007-2008 average propane wholesale to RAC price ratio of 76 percent. This ratio was applied to low crude oil price forecast to obtain the low wholesale propane price forecast.
U.S. EIA data on wholesale to retail price margins was used to estimate the high price margin of 64 cents based on the 2000-2004 data and low price margins of 55 cents based on the 1994-2004 data. Table B.4 and Figures B.6, B.7, and B.8 display E85, B20, and propane retail price forecasts for 2009 to 2030.

Table B.4: California Petroleum-Related Alternative Transportation Fuel Retail Price Forecasts (2008 cents per gallon)

	High Crude Oil Price Forecast				Low Crude Oil Price Forecast			
Year	RFG	E85	Propane	Bio-Diesel	RFG	E85	Propane	Bio-Diesel
2009	290	225	244	354	234	176	168	299
2010	347	263	291	402	262	195	187	324
2011	369	280	310	425	273	204	196	335
2012	399	301	333	450	287	214	204	346
2013	413	311	345	462	297	222	212	356
2014	427	321	358	489	308	230	220	367
2015	436	328	367	498	317	236	227	376
2016	440	331	370	501	317	236	227	376
2017	442	333	372	501	317	236	227	376
2018	444	334	374	506	317	236	227	376
2019	447	336	376	506	317	236	227	376
2020	446	335	375	505	317	236	227	376
2021	446	336	376	507	317	236	227	376
2022	451	340	380	513	317	236	227	376
2023	448	337	378	513	317	236	227	376
2024	451	339	380	516	317	236	227	376
2025	455	342	383	518	317	236	227	376
2026	458	344	386	521	317	236	227	376
2027	464	349	392	528	317	236	227	376
2028	469	353	397	532	317	236	227	376
2029	472	355	400	537	317	236	227	376
2030	480	361	406	542	317	236	227	376

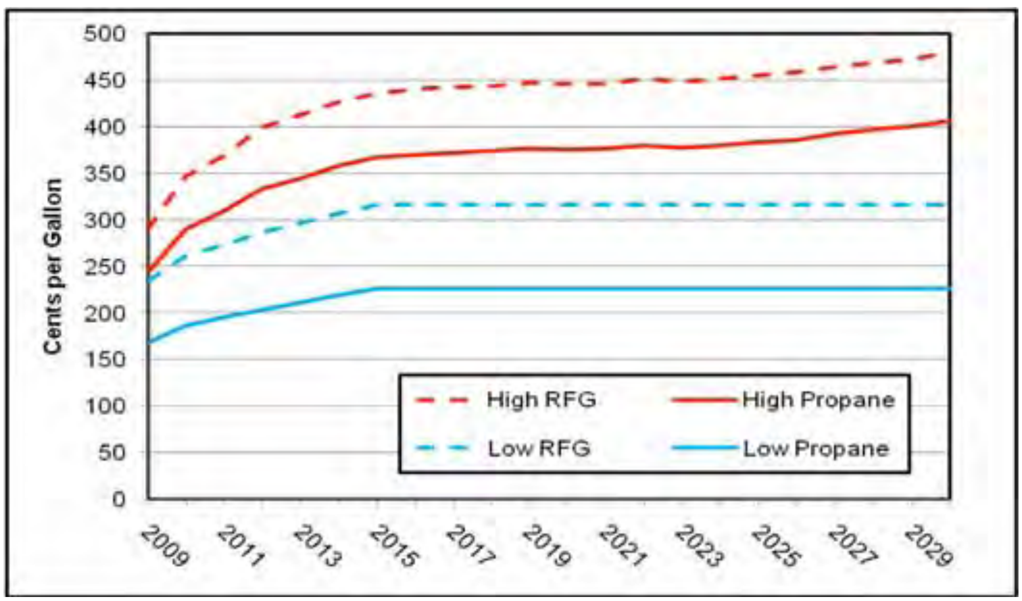
Source: California Energy Commission

Figure B.6: California RFG and E85 Fuel Price Forecasts (2008 cents per gallon)



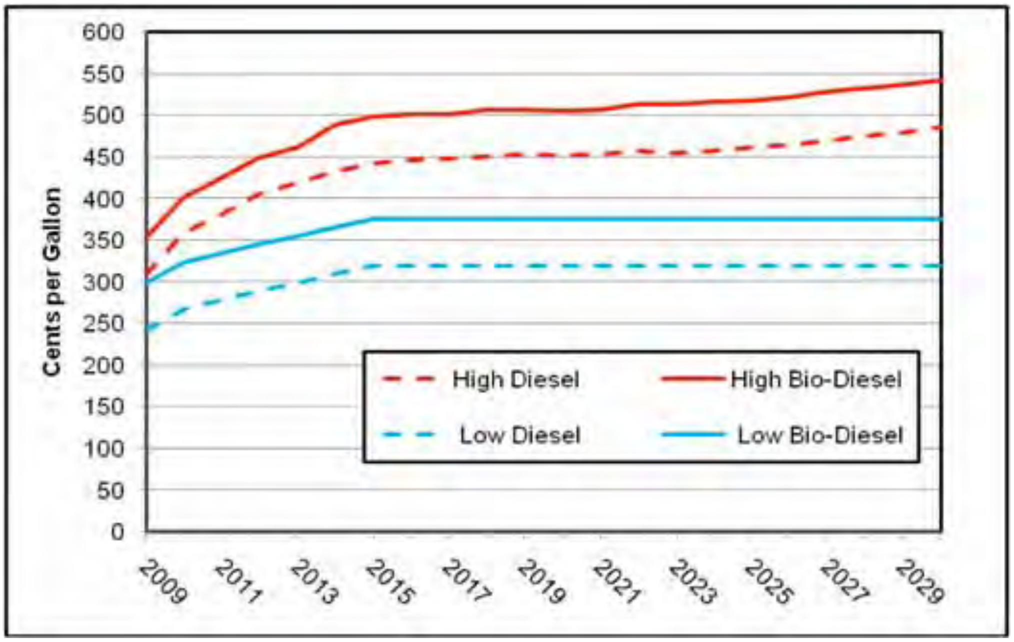
Source: California Energy Commission

Figure B.7: California RFG and Propane Fuel Price Forecasts (2008 cents per gallon)



Source: California Energy Commission

Figure B.8: California Diesel and Biodiesel Fuel Price Forecasts (2008 cents per gallon)



Source: California Energy Commission

Natural Gas Transportation Fuels

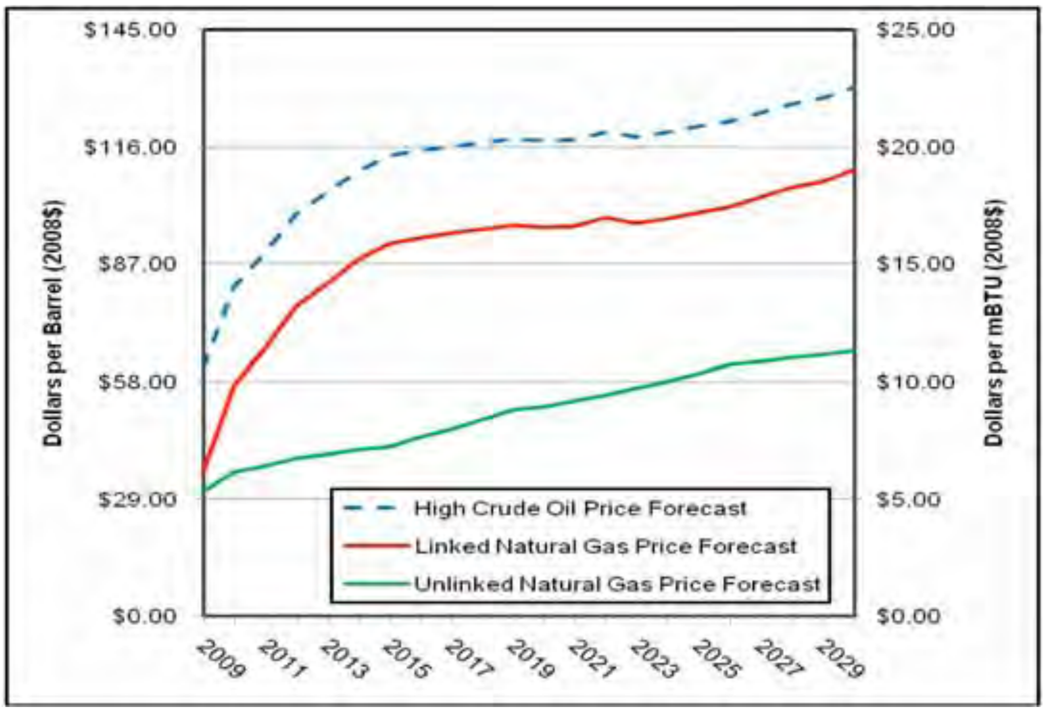
There are at least two alternative views on the relationship between crude oil and natural gas prices, one that relies on a strong historical price relationship between these primary fuels, and another that delinks these prices on the basis of the increasingly optimistic natural gas supply outlook and the declining substitution between the fuels in some uses. Due to the uncertainty in the long-term relationship between crude oil and natural gas commodity prices, CNG, LNG, and hydrogen transportation fuel price forecasts were developed as price bands based on four distinct natural gas commodity price forecasts, and associated with the high and low crude oil price cases. The high boundary of each price band is linked to crude oil price forecasts, and the low boundaries are unlinked to crude oil price cases and use alternative natural gas price forecasts used within the Energy Commission. Staff developed these high and low price bands for natural gas prices using different methods or forecasts available to the Energy Commission. Natural gas commodity prices in the following discussion refer to the natural gas prices at Henry Hub.

The natural gas price band associated with the High Crude Oil Price Case is thus bounded by a high (linked) natural gas price and a lower (unlinked) natural gas price. The upper boundary was calculated from the historical 2006-2008 cost differential between California petroleum and natural gas prices and is referred to as the "high oil price linked" natural gas price. The lower unlinked natural gas price is the same as the reference natural gas price forecast developed for the *2007 IEPR* and is referred to as the "high oil price unlinked" natural gas price. Figure B-9 illustrates the projected range of natural gas prices associated with the High Oil Price Case.

Similarly, the upper boundary of the low natural gas price band is linked to the low crude oil price case, and the lower boundary is unlinked to crude oil price. More specifically, the upper boundary forecast was adapted from an existing "High Gas Forecast Scenario"[clxxix] used in the

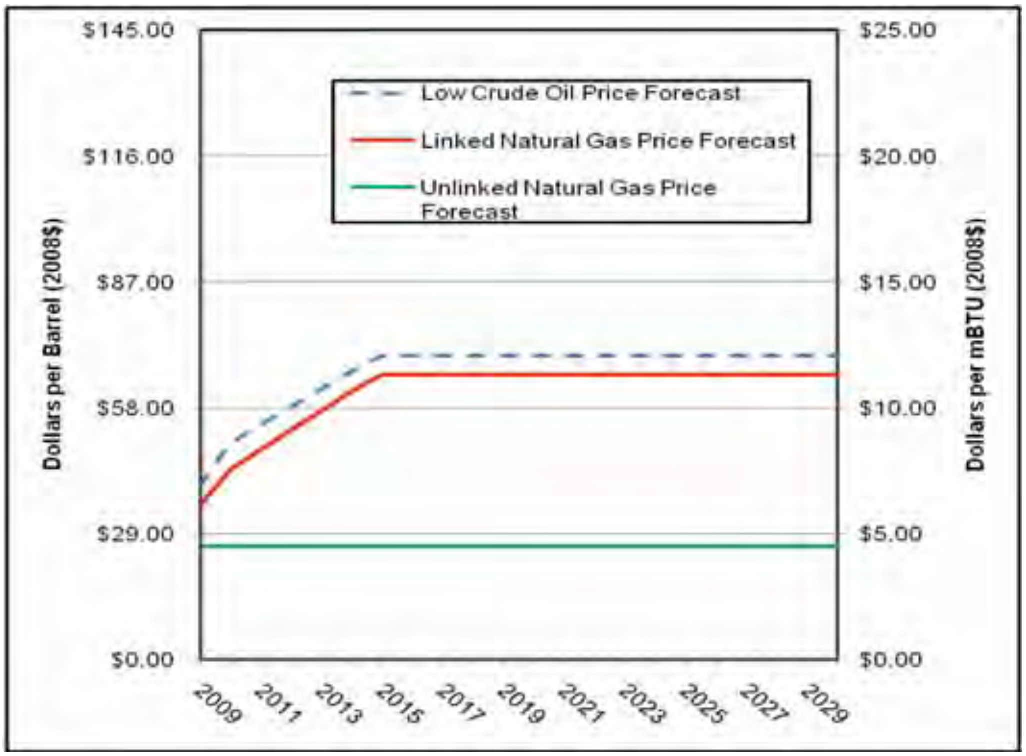
2007 IEPR, with revisions made to the early years to reflect current market prices and very minor adjustments in mid-term years, as well as extension beyond 2020, to conform to the trends assumed for the Low Crude Oil Price Case. This is referred to as the “low oil price linked” natural gas price forecast. For the lower boundary of natural gas prices, staff assumed the low natural gas price forecast for 2009 (per the U.S. EIA *Short Term Energy Outlook* projection of the 2009 natural gas price as of March 2009) will remain the same over the entire forecast period. This is referred to as the "low oil price unlinked" natural gas price forecast. Figure B.10 illustrates the range of natural gas prices associated with the Low Oil Price Case. Table B.5 presents the data illustrated in Figures B.9 and B.10 that has been used in forecasting CNG, LNG, and hydrogen prices.

Figure B.9: High Crude Oil Price Case: Range of Natural Gas Prices (2008 cents per gallon)



Source: California Energy Commission

Figure B.10: Low Crude Oil Price Case: Range of Natural Gas Prices (2008 cents per gallon)



Source: California Energy Commission

Table B.5: *IEPR 2009* Henry Hub Natural Gas Price Projections and the Energy Commission Crude Oil Price Forecasts (2008 cents per gallon)

	Dollars per Barrel		High Crude Oil Case, Dollars per mBTU		Low Crude Oil Case, Dollars per mBTU	
Year	High Crude Oil Price Forecast	Low Crude Oil Price Forecast	Linked Natural Gas Forecast	Unlinked Natural Gas Forecast	Linked Natural Gas Forecast	Unlinked Natural Gas Forecast
2009	$61.49	$40.09	$6.15	$5.33	$6.15	$4.51
2010	$81.37	$49.96	$9.84	$6.15	$7.58	$4.51
2011	$89.77	$54.14	$11.41	$6.40	$8.36	$4.51
2012	$99.49	$58.31	$13.21	$6.75	$9.13	$4.51
2013	$104.64	$62.48	$14.17	$6.91	$9.91	$4.51
2014	$110.11	$66.65	$15.19	$7.10	$10.68	$4.51
2015	$113.85	$70.00	$15.88	$7.23	$11.31	$4.51
2016	$115.15	$70.00	$16.13	$7.66	$11.31	$4.51
2017	$116.16	$70.00	$16.31	$7.98	$11.31	$4.51
2018	$117.05	$70.00	$16.48	$8.39	$11.31	$4.51
2019	$118.02	$70.00	$16.66	$8.81	$11.31	$4.51
2020	$117.54	$70.00	$16.57	$8.94	$11.31	$4.51
2021	$117.83	$70.00	$16.63	$9.20	$11.31	$4.51
2022	$119.69	$70.00	$16.97	$9.46	$11.31	$4.51
2023	$118.50	$70.00	$16.75	$9.73	$11.31	$4.51
2024	$119.62	$70.00	$16.96	$10.01	$11.31	$4.51
2025	$120.98	$70.00	$17.21	$10.37	$11.31	$4.51
2026	$122.20	$70.00	$17.44	$10.73	$11.31	$4.51
2027	$124.47	$70.00	$17.86	$10.87	$11.31	$4.51
2028	$126.62	$70.00	$18.26	$11.01	$11.31	$4.51
2029	$127.95	$70.00	$18.51	$11.17	$11.31	$4.51
2030	$130.71	$70.00	$19.02	$11.32	$11.31	$4.51

Source: California Energy Commission

Each natural gas-based alternative fuel (CNG, LNG, and hydrogen) has a price forecast based on one of these four distinct natural gas commodity price forecasts. Each fuel price forecast will use the same dealer and retailer margins outlined in the *Transportation Fuel Price and Demand Forecasts* staff report discussed at the February 10, 2009, staff workshop.[clxxx] Tables B-6 and B-7 provide CNG, LNG, and hydrogen price forecasts for 2009-2030. CNG prices are also illustrated in Figures B.11 and B.12.

Table B.6: High Crude Oil Price Case, California Natural Gas-Based Alternative Transportation Fuel Price Forecasts (2008 cents per gallon)

Year	Linked (high) Price Cases			Unlinked (low) Price Cases		
	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)
2009	461	243	213	448	233	196
2010	516	288	287	461	239	213
2011	540	306	319	465	242	218
2012	567	328	356	470	246	225
2013	581	340	375	472	248	228
2014	596	352	396	475	250	232
2015	607	361	410	477	252	234
2016	610	364	415	483	257	243
2017	613	366	419	488	260	250
2018	616	368	422	494	265	258
2019	618	370	426	501	270	267
2020	617	369	424	503	272	269
2021	618	370	425	506	275	274
2022	623	374	432	510	278	280
2023	620	371	427	514	281	285
2024	623	374	432	519	284	291
2025	627	377	437	524	288	298
2026	630	379	441	529	292	305
2027	636	385	450	532	294	308
2028	642	389	458	534	295	311
2029	646	392	463	536	297	314
2030	654	399	473	538	299	317

Source: California Energy Commission

Table B.7: Low Crude Oil Price Case, California Natural Gas-Based Alternative Transportation Fuel Price Forecasts (2008 cents per gallon)

Year	Linked (high) Price Cases			Unlinked (low) Price Cases		
	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)	Hydrogen (GGE)	CNG (GGE)	LNG (DGE)
2009	448	233	196	436	223	179
2010	482	260	242	436	223	179
2011	494	270	257	436	223	179
2012	505	279	273	436	223	179
2013	517	288	289	436	223	179
2014	529	298	304	436	223	179
2015	538	305	317	436	223	179
2016	538	305	317	436	223	179
2017	538	305	317	436	223	179
2018	538	305	317	436	223	179
2019	538	305	317	436	223	179
2020	538	305	317	436	223	179
2021	538	305	317	436	223	179
2022	538	305	317	436	223	179
2023	538	305	317	436	223	179
2024	538	305	317	436	223	179
2025	538	305	317	436	223	179
2026	538	305	317	436	223	179
2027	538	305	317	436	223	179
2028	538	305	317	436	223	179
2029	538	305	317	436	223	179
2030	538	305	317	436	223	179

Source: California Energy Commission

Transportation Electricity Rates

The final set of fuel price projections relate to vehicle electricity rates for electric vehicles (EVs) and PHEVs. Like the natural gas-based alternative fuels, there are four electricity rate forecasts for vehicle use that have been combined with the high and low crude oil price forecasts (a high and low band for each) in different price scenarios. Unlike the natural gas-based fuel prices, these rates are not determined by either the discussed natural gas or crude oil price forecasts.

The 2009 high price forecast for electricity was estimated at 473 cents per GGE based on the 2009 weighted average EV rate using the method described in the *Transportation Fuel Price and Demand Forecasts* staff report cited above. This price initiates the upper boundary of the electricity price ranges associated with both the crude oil price cases, the only difference being that in the High Crude Oil Price Case the electricity rate increases by 30 percent between 2010 and 2020, while in the Low Crude Oil Price Case this rate is held constant.[clxxxi] The 2009 low price for electricity is established at 180 cents per GGE, based on the lowest currently prevailing off-peak price at Pacific Gas and Electric (PG&E). This price initiates the lower boundary of the electricity price ranges associated with both crude oil price cases. Again, in the High Crude Oil Price Case the rate increases by 30 percent between 2010 and 2020, while in the Low Crude Oil Price Case the rate is held constant. It should be noted that both of these prices involve some level of subsidy for EVs and are based on the assumption that the consumer's use of electricity for EVs will not move them to the higher rate categories. Table B-8 shows the electricity price forecasts for the high and low price bands.

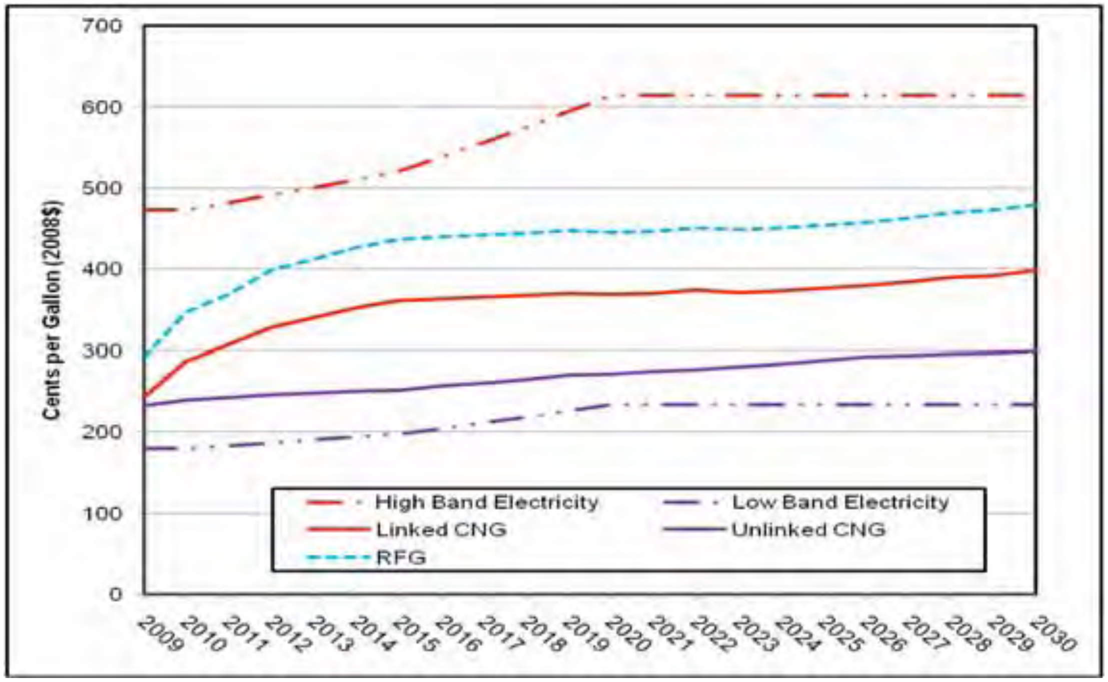
Table B.8: Electric Vehicle Electricity Price Forecasts
(2008 cents per gallon)

Year	High Crude Oil Price Case		Low Crude Oil Price Case	
	High Rate	Low Rate	High Rate	Low Rate
2009	473	180	473	180
2010	473	180	473	180
2011	482	184	473	180
2012	491	187	473	180
2013	500	191	473	180
2014	510	194	473	180
2015	520	198	473	180
2016	537	205	473	180
2017	556	212	473	180
2018	575	219	473	180
2019	594	226	473	180
2020	614	234	473	180
2021	614	234	473	180
2022	614	234	473	180
2023	614	234	473	180
2024	614	234	473	180
2025	614	234	473	180
2026	614	234	473	180
2027	614	234	473	180
2028	614	234	473	180
2029	614	234	473	180
2030	614	234	473	180

Source: California Energy Commission

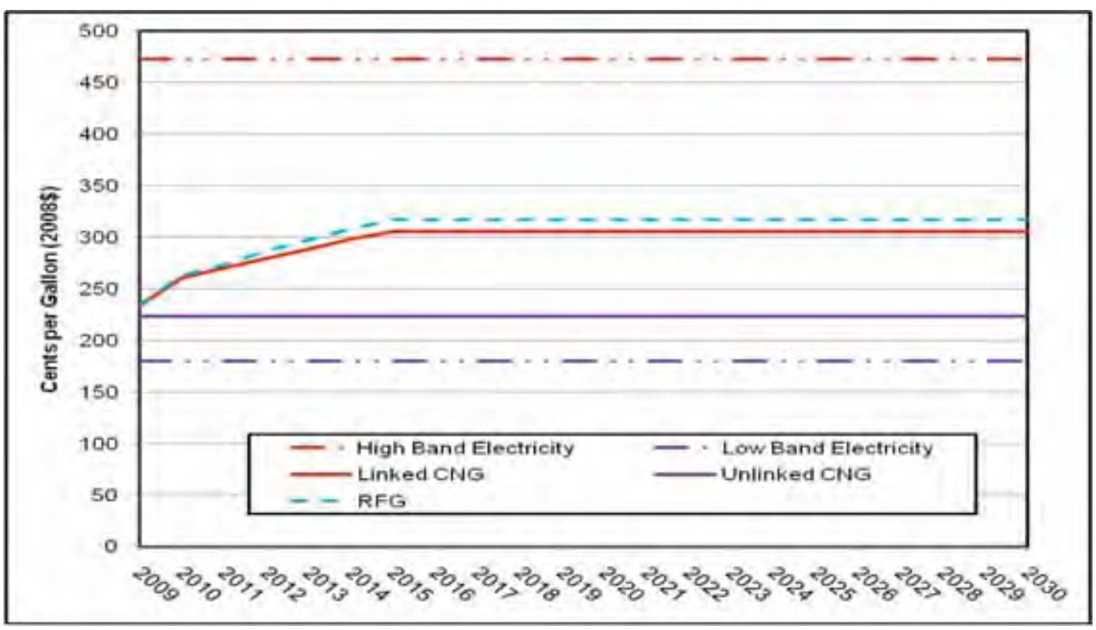
Figures B.11 and B.12 illustrate the combination of the gasoline, CNG, and electricity price forecasts corresponding to the High and Low Crude Oil Price Cases.

Figure B.11: California High Crude Oil Price Case:
CNG, Electricity, and Gasoline Retail Fuel Prices (2008 cents per gallon)



Source: California Energy Commission

Figure B.12: California Low Crude Oil Price Case:
CNG, Electricity, and Gasoline Retail Fuel Prices (2008 cents per gallon)



Source: California Energy Commission

APPENDIX C

CRUDE OIL IMPORTS AND FORECASTS

Table C.1: California Foreign Crude Oil Imports by Country (Thous. Barrels)

Country	2000	2001	2002	2003	2004	2005	2006	2007	2008
ALGERIA									996
ANGOLA		3,127	17,552	8,414	6,014	12,912	14,979	21,038	7,775
ARGENTINA	6,993	7,030	12,834	7,504	8,119	6,213	3,484	2,174	2,976
AUSTRALIA	5,557	8,248	5,841	7,646	4,360	650			2,088
AZERBAIJAN								1,523	
BOLIVIA					260	246	299	307	642
BRAZIL				953	1,893	12,474	17,938	22,453	26,078
BRUNEI	651	1,613	392	1,778	725	417			
CAMEROON							337		
CANADA		1,977	3,559	4,421	2,826	4,942	2,450	5,320	9,401
CHAD					2,293		1,285	3,885	355
CHINA, PEOPLES REP	835	664					210	554	702
COLOMBIA	1,237	1,988	2,190	1,828	4,062	4,180	9,362	11,813	19,860
CONGO (BRAZZAVILLE)		399							
ECUADOR	36,862	23,871	27,410	39,318	50,631	67,705	71,174	55,456	62,507
EQUATORIAL GUINEA			1,958	583		1,846	1,040	866	
INDONESIA	4,110	2,401	5,222	2,959	2,792			168	166
IRAQ	51,249	54,307	39,512	37,371	51,119	34,160	56,163	57,788	76,225
KUWAIT	5,766	1,728	3,808	3,343	277	1,403		300	3,105
LIBYA						581			
MALAYSIA	2,910	118	1,194			418	1,123		
MEXICO	14,858	18,288	18,533	16,469	14,284	19,316	15,473	9,214	1,175
NIGERIA		312		1,084		946	736	5,447	2,766
NORWAY		37	385				497	1,168	1,531
OMAN		5,444	6,060	2,835	321	2,985	6,326	4,400	3,013
PERU	1,494	2,524	1,128	2,447	383	1,501	962	1,841	2,684
QATAR			3,194						
RUSSIA								2,219	837
SAUDI ARABIA	30,544	42,726	36,256	83,477	86,051	95,507	86,976	72,296	82,969
TRINIDAD & TOBAGO								1,060	
UNITED ARAB EMIRATES	477	4,723	3,505	3,645	639	2,110		925	450
VENEZUELA	3,014	5,183	321	1,725	711	2,140	4,120	4,706	3,802
VIETNAM	2,367	974		291		399	1,883		
YEMEN	9,802	8,702	7,884	2,000		1,050	2,658	1,157	
Grand Total	178,726	196,384	200,711	230,091	237,760	274,101	299,475	288,078	312,103

Source: Energy Information Administration (EIA), company-level imports.

Table C.2

Baker & O'Brien Crude Oil Import Forecast - Southern California

Thousands of Barrels Per Day

Scenario A	2008	2009	2010	2011	2012	2013	2014	2015
Total Imports	**502**	**525**	**605**	**644**	**677**	**704**	**741**	**787**
Middle East	257	269	315	332	344	352	367	392
Latin America	198	207	225	237	248	259	270	282
West Africa	23	31	44	54	63	73	82	90
Canada	20	17	20	20	20	21	21	21
Pacific Rim	4	1	1	1	1	1	1	1
Scenario A	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Total Imports	**827**	**866**	**896**	**920**	**944**	**968**	**991**	**1,014**
Middle East	442	464	479	490	500	510	520	529
Latin America	239	244	248	251	255	259	263	266
West Africa	92	100	107	114	121	127	134	140
Canada	53	57	61	64	68	71	74	77
Pacific Rim	1	1	1	1	1	1	1	1

Scenario B	2008	2009	2010	2011	2012	2013	2014	2015
Total Imports	**502**	**525**	**605**	**644**	**677**	**704**	**733**	**772**
Middle East	257	269	315	332	344	352	363	384
Latin America	198	207	225	237	248	259	268	278
West Africa	23	31	44	54	63	73	80	88
Canada	20	17	20	20	20	21	21	21
Pacific Rim	4	1	1	1	1	1	1	1
Scenario B	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Total Imports	**805**	**837**	**864**	**879**	**891**	**903**	**914**	**924**
Middle East	428	447	462	468	472	476	480	483
Latin America	235	238	242	243	244	245	246	247
West Africa	89	95	102	107	112	116	120	124
Canada	52	55	58	60	63	65	67	69
Pacific Rim	1	1	1	1	1	1	1	1

Scenario C	2008	2009	2010	2011	2012	2013	2014	2015
Total Imports	**502**	**525**	**605**	**644**	**677**	**704**	**741**	**787**
Middle East	257	269	315	332	344	352	367	392
Latin America	198	207	225	237	248	259	270	282
West Africa	23	31	44	54	63	73	82	90
Canada	20	17	20	20	20	21	21	21
Pacific Rim	4	1	1	1	1	1	1	1
Scenario C	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Total Imports	**812**	**837**	**857**	**874**	**886**	**897**	**908**	**918**
Middle East	433	447	457	465	469	473	477	480
Latin America	236	238	240	242	243	244	245	246
West Africa	90	95	101	106	111	115	119	123
Canada	52	55	57	60	62	64	66	68
Pacific Rim	1	1	1	1	1	1	1	1

Scenario A	1 percent per year increase in refinery runs through 2023.
Scenario B	1 percent per year increase in refinery runs for first five years, 0.5 percent per year for next five years, and no increase for the last five years (through 2023).
Scenario C	1 percent per year increase in refinery runs for the first seven years, and no increase for the last eight years (through 2023).

Source: Baker & O'Brien.

GLOSSARY

AB 1007	Assembly Bill 1007
AGT	Above-ground storage tank
AOE	Annual Energy Outlook
APTA	American Public Transportation Association
ARB	California Air Resources Board
ASTM	American Society for Testing and Materials
ATA	American Trucking Association
B5	Diesel with 5 percent biodiesel content
B20	Diesel with 20 percent biodiesel content
BOE	California Board of Equalization
BPD	Barrels per day
CAFE	Corporate average fuel economy
CALCARS	California Conventional and Alternative Fuel Response Simulator
CaRFG	California Reformulated Gasoline
CARBOB	California reformulated blendstock for oxygenate blending
CBI	Caribbean Basin Initiative
CCR	Continuous catalyst regeneration
CDFA	California Department of Food and Agriculture
CFP	Clean Fuels Project
CI	Carbon intensity
CNG	Compressed natural gas
CPG	Cents per gallon
CVS	California Vehicle Survey
DGS	Distillers grain with solubles
DMS	Division of Measurement Standards
DMV	California Department of Motor Vehicles
DOF	California Department of Finance
E6	Gasoline with 6 percent ethanol content
E10	Gasoline with 10 percent ethanol content

E85	Fuel with 85 percent ethanol content, 15 percent gasoline
EIS	Environmental impact statement
EISA	Energy Independence and Security Act of 2007
EPE	Empresa de Pesquisa Energética
FAA	Federal Aviation Administration
FEVs	Full electric vehicles
FFVs	Flexible fuel vehicles
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas
GIS	Geographic information system
GSP	Gross state product
GVWR	Gross vehicle weight rating
HOV	High Occupancy Vehicle
IEPR	*Integrated Energy Policy Report*
KMP	Kinder Morgan Pipeline Company
LCFS	Low Carbon Fuel Standard
LNG	Liquefied natural gas
MMS	Minerals Management Services
MTBE	Methyl tertiary butyl ether
NOI	Notice of Intent
NOPR	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Land Act
OEMs	Original Equipment Manufacturers
OPIS	Oil Price Information Service
PADD V	Petroleum Administration for Defense District V
PHEVs	Plug-in hybrid electric vehicles
PZEV	Partial zero emission vehicle
RAC	Refiner acquisition cost
RFS	Renewable Fuel Standard
RFS2	Renewable Fuel Standard 2

RIN	Renewable Indentification Number
RVO	Renewable volume obligation
SAE	Society of Automotive Engineers
SB 375	Senate Bill 375
SPR	Strategic Petroleum Reserve
SULEV	Super-ultra-low-emission vehicle
SWRCB	State Water Resources Control Board
TAME	Tertiary amyl methyl ether
TBD	Thousand barrels per day
TEUs	Twenty foot equivalent units
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
UL	Underwriters' Laboratories
USDA	United States Department of Agriculture
UST	Underground storage tanks
UTRR	Undiscovered technically recoverable resources
VLCC	Very large crude carrier
VMT	Vehicle miles traveled
ZEV	Zero emission vehicle

End Notes

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[i] *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report*, Final Staff Report; September 2007. Report can be found at http://www.energy.ca.gov/2007publications/ENERGY COMMISSION-600-2007-009/ENERGY COMMISSION-600-2007-009-SF.PDF

[ii] DMV Registration Database, file passes for 2001 to 2008.

[iii] Natural gas includes light-duty vehicles that operate on compressed natural gas (CNG) or liquefied natural gas (LNG).

[iv] US DOT FHWA VIUS refers to GVWR Class 1 and 2 as light-duty.

[v] "Alternative fuels" refers to dedicated vehicles that operate on electricity, CNG, LNG, propane, methanol, butane or hydrogen. In addition, this category includes vehicles under the technology category of "hybrids."

[vi] Total cargo containers handled by all the ports in the continental United States (excludes totals for Alaska, Hawaii, Guam, and Puerto Rico) during 2008 amounted to 38,932,828 twenty-foot equivalent units (TEUs). The ports of Long Beach, Los Angeles, and Oakland handled 16,436,354 TEUs for the same year. Data provided by the American Association of Port Authorities (AAPA), Port Industry Statistics. Information available from http://www.aapa-ports.org/Industry/content.cfm?ItemNumber=900&navItemNumber=551; Internet; accessed on August 7, 2009. Complete data for all North American ports for 1990 through 2008 available from http://aapa.files.cms-plus.com/Statistics/CONTAINERTRAFFICNORTHAMERICA1990%2D2008.xls; Internet; accessed on August 7, 2009.

[vii] Annual statistics are also available for the ports of Hueneme and San Diego, but no recent monthly figures. However, these two ports represent approximately 0.7 percent of total port container activity in the state and the exclusion of their data from the TEU, and diesel fuel comparison is not of significant consequence.

[viii] The numbers of TEUs (imports, exports, full, and empty) processed by the ports of Long Beach, Los Angeles, and Oakland averaged 49,468 TEUs in 2007, 44,908 in 2008, and 37,857 during the first six months of 2009. Container statistics for the Port of Long Beach are available from http://www.polb.com/economics/stats/default.asp; Internet; accessed on December 23, 2009. Container statistics for the Port of Los Angeles are available from http://www.portoflosangeles.org/maritime/stats.asp; Internet; accessed on December 23, 2009. Container statistics for the Port of Oakland are available from http://www.portofoakland.com/maritime/facts_cargo.asp; Internet; accessed on December 23, 2009.

[ix] United States. Dept. of Commerce. Bureau of Economic Analysis. Regional Economic Accounts. June 2, 2009. http://www.bea.gov/regional/gsp/

[x] *Weekly Traffic of Major U.S. Railroads for the Week Ending December 19, 2009*, Association of American Railroads; available from http://www.aar.org/NewsAndEvents/PressReleases/2009/12_WTR/~/media/AAR/Weekly_Traffic_Reports/wtr%20122309.ashx: Internet accessed on December 23, 2009.

[xi] *ATA Truck Tonnage Index Slipped 0.3 Percent in September*, American Trucking Association (ATA) press release, October 23, 2009; available from http://www.truckline.com/pages/article.aspx?id=601%2F{8E1C7279-ED27-4C03-B189-CEEEE26BBB12} Internet; accessed on November 22, 2009.

[xii] *Recession Catches up to Transit Ridership*, American Public Transportation Association press release, September 25, 2009, available from http://www.apta.com/mediacenter/pressreleases/2009/Pages/090925_ridership_report.aspx; Internet; accessed on November 22, 2009.

[xiii] *August 2009 Airline Traffic Data: System Traffic Down 4.1 Percent in August From 2008*, U.S. Department of Transportation, Bureau of Transportation Statistics (BTS) press release, November 13, 2009, page 1; available from http://www.bts.gov/press_releases/2009/bts053_09/html/bts053_09.html; Internet; accessed on November 22, 2009.

[xiv] *A Long-Term Look at California Taxable Sales and Personal Income Growth*, California State Board of Equalization, Economic Perspective, May 2002, Chart II-1, page 4; available from http://www.boe.ca.gov/news/pdf/ep5-02.pdf; Internet; accessed on August 5, 2009.

[xv] A link to the BOE website containing taxable gasoline and diesel fuel sales figures for the last 10 years is as follows: http://www.boe.ca.gov/sptaxprog/spftrpts.htm

[xvi] California gasoline demand for the first six months of 2009 averaged 40.83 million gallons per day compared to an average of 41.25 million gallons per day for the same period in 2008. For the most recent 12-month period, gasoline demand has averaged 40.55 million gallons per day compared to the previous 12-month average of 41.96 million gallons per day.

[xvii] California diesel fuel demand for the first six months of 2009 averaged 8.55 million gallons per day compared to an average of 9.35 million gallons per day for the same period in 2008. For the most recent 12-month period, diesel fuel demand has averaged 8.98 million gallons per day compared to the previous 12-month average of 9.99 million gallons per day.

[xviii] Wikipedia, "Ford Model T"; available from http://en.wikipedia.org/wiki/Ford_Model_T; Internet; accessed on July 31, 2009.

[xix] U.S. General Accounting Office, *Importance and Impact of Federal Alcohol Fuel Tax Incentives*, GAO/RCED-84-1, Washington D.C.: Government Printing Office, 1984, page 1. A link to the document is as follows: http://archive.gao.gov/d6t1/124476.pdf

[xx] Ibid, page1.

[xxi] Ibid, pages 4-5. The initial primary federal legislative acts addressing ethanol blending exemption from a portion of the federal excise taxation rates on gasoline included: the Energy Tax Act of 1978 (Public Law 95-618, Nov. 9, 1978); the Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96-223, Apr. 2, 1980); and the Highway Revenue Act of 1982 (Public Law 97-424-Title V, Jan. 6, 1983).

[xxii] The federal requirement was one of the programs contained in the 1990 Clean Air Act Amendments. The California Air Resources Board promulgated regulations to meet compliance with the winter oxygenate program. A review of that program is summarized in: *An Overview of the Use of Oxygenates in Gasoline*, California Air Resources Board, September 1998. A link to the document is as follows: http://www.arb.ca.gov/fuels/gasoline/pub/oxyrprt.pdf

[xxiii] The U.S. Environmental Protection Agency published the Final Rule for their reformulated gasoline regulations in the Federal Register on February 16, 1994 (59 FR 7716). Roughly 70 percent of California's gasoline sales were estimated to occur within the mandated RFG geographic regions of the state. A link to the Final Rule is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/1996/November/Day-13/pr-23839DIR/Other/fuel.txt.html

[xxiv] The California Air Resources Board adopted reformulated gasoline regulations on November 22, 1991, referred to as CaRFG Phase 2 regulations. A link to the staff report is as follows: http://www.arb.ca.gov/fuels/gasoline/carfg2/carfg2.pdf

[xxv] Governor Davis issued Executive Order D-5-99 on March 25, 1999, directing various state agencies to develop regulations to eliminate the use of MTBE in California. Part of that order directed the California Energy Commission to "develop a timetable for the removal of MTBE from California gasoline not later than December 31, 2002." A copy of the Executive Order may be viewed at the following link: http://www.arb.ca.gov/fuels/gasoline/carfg3/eod0599.pdf

On July 1, 1999, the Energy Commission issued its report, *Timetable for the Phaseout of MTBE From California's Gasoline Supply*, which found that the phase-out deadline of December 31, 2002, could not be advanced. The link to a copy of this report is as follows: http://energyarchive.ca.gov/mtbe/documents/1999-07-01_300-99-003.PDF

Additional analysis by the Energy Commission and consultants working for the Energy Commission determined that the original phase-out deadline should be extended an additional year. As a consequence of this new analysis and other sources of information, Governor Davis issued Executive Order D-52-02 on March 14, 2002, delaying the final MTBE phase-out deadline until January 1, 2004. A link to a copy of that Executive Order is as follows: http://www.calgasoline.com/EOD52-02.PDF

[xxvi] *MTBE Contamination From Underground Storage Tanks*, Government Accountability Office, GAO-02-753T, May 21, 2002. This report provides an overview of the drinking water contamination concerns and evolution of various state actions. A copy of the document may be accessed at the following link: http://www.gao.gov/new.items/d02753t.pdf

[xxvii] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," *Federal Register*, Vol. 74, No. 99, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[xxviii] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Extension of Comment Period," *Federal Register*, Vol. 74, No. 128, pp. 32091-02, July 7, 2009. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/July/Day-07/a15947.pdf

[xxix] United States Environmental Protection Agency, "Renewable Fuel Standard for 2009, Issued Pursuant to Section 211(o) of the Clean Air Act," *Federal Register*, Vol. 73, No. 226, November 21, 2008. A link to the document is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2008/November/Day-21/a27613.pdf

To quote from the specific portion of the regulation from page 70643:

"This standard is calculated as a percentage, by dividing the amount of renewable fuel that the Act requires to be used in a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the Act. In this notice we are publishing an RFS of 10.21% for 2009. This standard is intended to lead to the use of 11.1 billion gallons of renewable fuel in 2009, as required by the Energy Independence and Security Act of 2007 (EISA). As discussed below, we expect the 11.1 billion gallons of renewable fuel required in 2009 to include approximately 0.5 billion gallons of biodiesel and renewable diesel."

[xxx] United States Environmental Protection Agency, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," *Federal Register*, Vol. 74, No. 99, page 24953, May 26, 2009. A link to the document is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

To quote from the specific portion of the regulation:

"In order for an obligated party to demonstrate compliance, the percentage standards would be converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and would continue to be referred to as its Renewable Volume Obligation (RVO). Since there would be four separate standards under the RFS2 program, there would likewise be four separate RVOs applicable to each refiner, importer, or other obligated party."

[xxxi] Energy Information Agency (EIA) Supply and Consumption Figures, June 2009.

[xxxii] *Annual Energy Outlook 2009*, Energy Information Administration, DOE/EIA-0383(2009), March 2009. A link to the report is as follows: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf. The revised Reference Case was released in April 2009.
A link to that information is as follows: http://www.eia.doe.gov/oiaf/servicerpt/stimulus/index.html
Table 11 contains the EIA projections for gasoline and diesel fuel.

[xxxiii] *Mid-Level Blend Ethanol: Challenges, Opportunities & Testing Follow Through*, James Frusti, Chrysler LLC, Joint IEPR and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues, California Energy Commission, Sacramento, California, April 14-15, 2009. A copy of this presentation may be viewed at the following link: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[xxxiv] University of Minnesota, Department of Mechanical Engineering, *Demonstration and Driveability Project to Determine the Feasibility of Using E20 as a Motor Fuel*, November 4, 2008, http://www.mda.state.mn.us/news/publications/renewable/ethanol/e20drivability.pdf

[xxxv] Oak Ridge National Laboratory, *Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines*, *Report 1*, publication number ORNL/TM-2008/117, October 2008, http://feerc.ornl.gov/publications/Int_blends_Rpt_1.pdf

[xxxvi] Deadline for submitting comments on the E15 waiver request was extended from May 21 to July 20, 2009. "Notice of Receipt of a Clean Air Act Waiver Application To Increase the Allowable Ethanol Content of Gasoline to 15 Percent; Extension of Comment Period," *Federal Register*, Vol. 74, No. 96, May 20, 2009, page 23704. A link to the notice is as follows: http://www.epa.gov/fedrgstr/EPA-AIR/2009/May/Day-20/a11785.pdf

[xxxvii] All of these registered vehicles (381,584) were in the light-duty class. The majority of these FFVs were either a variation of some type of sport utility vehicles (34.5 percent), pickup trucks (32.1 percent) or vans (15.1 percent).

[xxxviii] *Fuel Delivery Temperature Study*, California Energy Commission, Commission Report CEC 600 2009 002 CMF, March 2009, page 57. A link to the document is as follows: http://www.energy.ca.gov/2009publications/CEC-600-2009-002/CEC-600-2009-002-CMF.PDF

[xxxix] Staff estimates that there are a total of between 217,000 and 252,000 meters at nearly 10,000 retail fuel stations throughout California. On average, each meter is estimated as having dispensed between 75,000 and 87,500 gallons of transportation fuel during the period July 1, 2007, through June 30, 2008. Further assuming that a dispenser designed to dispense only one type of fuel would be equipped with two meters, the average fuel distribution during this period for such a dispenser is calculated at between 150,000 and 185,000 gallons. The lower estimate for number of meters at retail motor fuel locations originated from the California Division of Measurement Standards, County Monthly Report (CMR) summary for period July 1, 2007, through June 30, 2008. The higher estimate was derived by staff as part of its work associated with the Fuel Temperature study. As a point of reference, it is further estimated that each fuel dispenser in California distributed an average of 452,000 gallons of transportation fuel over the same period of time. The average distribution level is significantly higher than the "single-fuel" dispenser average because most dispensers are designed to sell three grades of gasoline and will include six meters per dispenser, rather than two. Dispensers that also sell diesel fuel (along with the three grades of gasoline) will normally have eight meters per dispenser (four for each side or face).

[xl] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, page 20. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[xli] A link to a description of this Authorization Suspension of E85 dispenser components is as follows: http://www.ul.com/global/eng/pages/offerings/perspectives/regulator/e85info/suspension/

[xlii] "Underwriters Laboratories Announces Development of Certification Requirements for E85 Dispensers," UL press release, October 16, 2007. A link to this press release is as follows: http://www.ul.com/global/eng/documents/offerings/perspectives/regulators/e85/e85certificationrequirements.pdf

[xliii] As of November 2007, UL had yet to receive any fueling hose assemblies for E85 compatibility testing. Refer to the following presentation: *E85 Dispensing Equipment Update*, Dennis A. Smith, U.S. Dept of Energy, November 17, 2008, slides 7-8. A link to this presentation is as follows: http://www1.eere.energy.gov/cleancities/toolbox/pdfs/uldoe.pdf

[xliv] National Association of Convenience Stores (NACS) and the Society of Independent Gasoline Marketers of America (SIGMA), Letter to Congress, March 27, 2006, page 2. A copy of the document may be accessed at the following link: http://www.sigma.org/pdf/E85-Mandates.pdf. According to the National Commission on Energy Policy's (NCEP) recent report: "Replacing an entire system can be expected to cost substantially more than $150,000 per facility depending upon the market." *Task Force on Biofuels Infrastructure*, NCEP, May 2009, Appendix B, page 53; available from http://www.energycommission.org/ht/a/GetDocumentAction/i/10232; Internet; accessed on August 2, 2009. Additional cost estimates for both new and retrofit scenarios are provided in the following brief paper: *Cost of Adding E85 Fueling Capability to Existing Gasoline Stations: NREL Survey and Literature Search*, National Renewable Energy Laboratory, Publication NREL/FS-540-42390, March 2008. A link to this document is as follows: http://www.afdc.energy.gov/afdc/pdfs/42390.pdf

[xlv] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory, Technical Report NREL/TP-540-41590, December 2007, Appendix C, page 41. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[xlvi] *Fuel Delivery Temperature Study*, California Energy Commission, CEC-600-2009-002-CMF, page 59. A link to this study is as follows: http://www.energy.ca.gov/2009publications/ENERGY COMMISSION-600-2009-002/ENERGY COMMISSION-600-2009-002-CMF.PDF

[xlvii] Based on data for 2008, 56 percent of the convenience stores were owned and operated by someone who only had one station. A link to this information and more is at the following link: http://www.nacsonline.com/NACS/News/Campaigns/GasPrices_2009/Pages/WhoSellsGas.aspx

[xlviii] National Association of Convenience Stores, NACS Online, Fact Sheets, Motor Fuels, Motor Fuel Sales, posted May 15, 2009. A link to the fact sheet is as follows: http://www.nacsonline.com/NACS/News/FactSheets/Motor%20Fuels/Pages/MotorFuelSales.aspx

[xlix] National Association of Convenience Stores, *NACS State of the Industry Report of 2007 Data* (1998 – 2007 data), December 2008 and 2009 press release (2008 data). Press release: *Convenience Store Sales, Profits Showed Gains in 2008*, NACS, April 7, 2009. A link to the press release is as follows: http://www.nacsonline.com/NACS/NEWS/PRESS_RELEASES/2009/Pages/PR040709.aspx

[l] One such example of government funding is the California Air Resources Board Alternative Fuel Incentive Program created through Assembly Bill 1811 (Laird, Chapter 48, Statutes of 2006). This activity was designed to provide $25 million "for the purposes of incentivizing the use and production of alternative fuels." A link to the ARB site is as follows: http://www.arb.ca.gov/fuels/altfuels/incentives/incentives.htm.

An example of a specific station in Brentwood that received grant money from this program (approximately $580,000) is as follows: *California Has New E85 Station Open to the Public*, Dimitri Stanich, California Air Resources Board, February 26, 2008. A link to the press release is as follows: http://www.arb.ca.gov/newsrel/nr022608.htm. The list of additional California programs that may provide other funding opportunities for prospective E85 retail station owners can be viewed at the following link: http://www.afdc.energy.gov/afdc/progs/state_summary.php/CA

Finally, the 2009 American Recovery and Reinvestment Act (Section 1123) provides for a tax credit of up to $50,000 per business through 2010 that can be applied to the installation of E85 dispensers. The specific language to the Section 1123 provisions are found on page 47 at the following link: http://thomas.loc.gov/home/h1/Recovery_Bill_Div_B.pdf

[li] *Mid-Level Blend Ethanol: Challenges - Opportunities & Testing Follow Through*, James Frusti, Chrysler, April 14, 2009, slide 11. A link to this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/09-Frusti_James_Mid-Level_Ethanol_Blends.pdf

[lii] *GM Update on Flex-Fuel Vehicle Challenges in CA*, James Ehlmann and Clay Okabayashi, General Motors, June 24, 2008, slides 4 through 8. A link to this presentation is as follows: http://www.netl.doe.gov/publications/proceedings/08/clean-cities-ca/pdfs/6.24Tues/Ehlmann%20%26%20Okabayashi%20-%20GM.pdf

[liii] Ibid., slide 9.

[liv] *The California Low-Emission Vehicle Regulations - With Amendments Effective April 17, 2009*, California Air Resources Board. A link to this document is as follows: http://www.arb.ca.gov/msprog/levprog/cleandoc/cleancomplete_lev-ghg_regs_3-09.pdf

The revised zero emission vehicle standards describe the multiple and complex compliance options for vehicle manufacturers. Some of these compliance pathways can include the increased sales of PZEVs. Hearing Date: 03/27/08, Adopted: 12/17/08. A link to this Final Regulation Order – Part 5 is as follows: http://www.arb.ca.gov/regact/2008/zev2008/zfrop5.pdf

For a historical summary of the ZEV regulation evolution, please refer to the following document: "Learning From California's Zero-Emission Vehicle Program," Louise Wells Bedsworth and Margaret R. Taylor, *California Economic Policy*, Volume 3, Number 4, September 2007. A link to the document is as follows: http://www.ppic.org/content/pubs/cep/EP_907LBEP.pdf

[lv] "California State Motor Vehicle Pollution Control Standards; Notice of Decision Granting a Waiver of Clean Air Act Preemption for California's 2009 and Subsequent Model Year Greenhouse Gas Emission Standards for New Motor Vehicles," U.S. Environmental Protection Agency (EPA), *Federal Register*, Vol. 74, No. 129 / Wednesday, July 8, 2009. A link to this publication is as follows: http://edocket.access.gpo.gov/2009/pdf/E9-15943.pdf

[lvi] *E85 Retail Business Case: When and Why to Sell E85*, C. Johnson and M. Melendez, National Renewable Energy Laboratory (NREL), Technical Report NREL/TP-540-41590, December 2007, Appendix E, page 43. A link to this report is as follows: http://www.afdc.energy.gov/afdc/pdfs/41590.pdf

[lvii] *National Survey of E85 and Gasoline Prices*, P. Bergeron, National Renewable Energy Laboratory, Technical Report NREL/TP-540-44254, October 2008. According to this study, "*The E85:gasoline price ratio was always higher than the E85:gasoline energy content ratio, signifying a higher per-mile cost for E85 in comparison to that of gasoline. The disparity diminished somewhat as the price of gasoline rose above $3 per gallon*." A link to this study is as follows: http://www.afdc.energy.gov/afdc/pdfs/44254.pdf

[lviii] "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule," U.S. Environmental Protection Agency, *Federal Register*, Vol. 74, No. 99, May 26, 2009, pp. 24920-1. A link to the proposed rule is as follows: http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[lix] An overview of the RIN requirements and some of the complicating factors are contained in the following paper: *The Changing RINs Landscape*, Oil Price Information Service (OPIS), 2009. A link to a copy of this document is as follows: http://www.scribd.com/doc/17121722/Briefing-on-RINs-Renewable-Identification-Numbers

[lx] A link to the California Air Resources Board website that contains background information and regulations is as follows: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

[lxi] The carbon intensity (CI) value for Brazilian sugarcane ethanol using average production processes is 73.40 gCO2e/MJ. This value includes both direct emissions and other indirect effects (such as changes in land use). If the Brazilian sugarcane-based ethanol production has electricity cogeneration from the burning of bagasse (sugarcane residue), the CI drops to 66.40 gCO2e/MJ. If mechanized harvesting is also included along with electricity generation, the CI value drops further to 58.20 gCO2e/MJ.

Average Midwestern ethanol produced from corn has a carbon intensity value of 99.40 gCO2e/MJ by comparison. Ethanol produced using corn at an average California facility has a carbon intensity value of between 80.70 and 88.9 gCO2e/MJ, depending on whether or not the distillers grain with solubles (DGS) co-product is wet or dry. California Air Resources Board, Modified Regulation Order, Table 6, page 43, posted July 20, 2009. A link to the document is as follows:
http://www.arb.ca.gov/regact/2009/lcfs09/lcfsmodtxt.pdf

[lxii] A more detailed historical examination of ethanol markets is presented in Paul Gallagher's paper: *Roles for Evolving Markets, Policies, and Technology Improvements in U.S. Corn Ethanol Industry Development*, Federal Reserve Bank of St. Louis, Regional Economic Development, Volume 5, Number 1, 2009. A copy of this document may be accessed at the following link:
http://research.stlouisfed.org/publications/red/2009/01/Gallagher.pdf

[lxiii] According to Ethanol Producer Magazine, as of June 26, 2009, there was 12.853 billion gallons of ethanol production capacity in the United States. However, only 10.622 billion gallons of capacity is operational, while another 1.358 billion gallons of incremental production capacity in under construction.

A link to Ethanol Producer Magazine's ethanol plant capacity information is as follows: http://www.ethanolproducer.com/plant-list.jsp?country=USA&view=

[lxiv] RFS2 corn-based ethanol limits for 2012 are currently set to 13.2 billion gallons. Staff estimates that U.S. ethanol capacity from corn-based facilities will be at least 13.5 billion gallons by the end of 2010.

[lxv] Recent presentation at the Platt's Advanced Biofuels conference by Ben Thorpe indicates that there is currently 3.56 million gallons per year cellulosic ethanol production capacity operational. Another 300,000 gallons of capacity is slated to be on-line sometime in 2009, along with another 4 million gallons by mid-2010. A link to this presentation is as follows: https://platts.com/Events/2009/pc934/presentations/Ben_Thorp.pdf

This total is far less than the 100 million gallons of cellulosic production capacity claimed by EPA in its May 26, 2009, NOPR, Table V.B.2–3, pp 24990-01. A link to the document is as follows:http://www.epa.gov/OMS/renewablefuels/rfs2_1-5.pdf

[lxvi] *Jury returns $10.4M verdict in biofuel lawsuit*, Associated Press, June 30, 2009. A link to the article is as follows: http://www.mercurynews.com/breakingnews/ci_12723637?nclick_check=1

United States District Court for the Southern District of Alabama, Mobile County, Parsons & Whittemore Enterprises Corporation v. Cello Energy, LLC, et al, case number 1:07-cv-00743-CG-B. A link to additional information is as follows: http://www.morelaw.com/verdicts/case.asp?n=1:07-cv-00743-CG-B&s=AL&d=40517

[lxvii] State of Oregon, Oregon Administrative Rules, Department of Agriculture, 603-027-0420, Standard Fuel Specifications, subsection (11) Biodiesel Blends Required

(a) When the production of biodiesel in Oregon from base feedstock grown or produced in Oregon, Washington, Idaho, and Montana reaches a level of at least 5 million gallons on an annualized basis for at least three months, the Department shall notify all retailers, nonretail dealers, and wholesale dealers in Oregon, in a notice that communicates,

(A) The biodiesel production in Oregon from base feedstock grown or produced in Oregon, Washington, Idaho, and Montana has reached a level of at least 5 million gallons on an annualized basis for at least three months, and

(B) Three months after the date of the notice, a retail dealer, nonretail dealer, or wholesale dealer may only sell or offer for sale diesel fuel in Oregon containing at least two percent biodiesel by volume or other renewable diesel with at least two percent renewable component by volume.

A link to these regulations is as follows: http://arcweb.sos.state.or.us/rules/OARS_600/OAR_603/603_027.html

[lxviii] http://www.syracuse.com/news/index.ssf/2009/05/sunoco_wins_auction_for_volney.html

[lxix] Harvest of sugarcane in Brazil normally begins in April and is usually completed during November.

[lxx] A more recent compilation of ethanol sugar and plants in Brazil from the Brazil Ministry of Agriculture indicates that there are a total of 395 facilities that produce ethanol (248 sugar/ethanol plants and 157

ethanol-only plants). Information is current as of March 13, 2009. A complete list of the individual facilities may be accessed at the following link: http://www.agricultura.gov.br/pls/portal/docs/PAGE/MAPA/SERVICOS/USINAS_DESTILARIAS/USINAS_CADASTRADAS/UPS_13-03-2009_0.PDF

Please note that the list is in Portuguese. All sugar/ethanol facilities are referred to as "Mista," ethanol-only facilities as "Álcool," and sugar mills as "Açúcar."

[lxxi] *An Overview of the Brazilian Sugarcane Industry*, Marcos Jank, UNICA, November 13, 2008, slide 10. A link to the presentation is as follows: http://english.unica.com.br/download.asp?mmdCode=9C382A63-916C-41E8-A4F9-381C6B60C60C

[lxxii] The Caribbean Basin Initiative or CBI is an economic development program designed, in part, to allow specific types of goods imported into the United States duty-free or at reduced tariff structures. A lengthy description of the program and eligible countries is contained in: "Guide to the Caribbean Basin Initiative," U.S. Department of Commerce, International Trade Commission, 2000 Edition. A link to the document is as follows: http://www.ita.doc.gov/media/Publications/pdf/cbi2000.pdf

Ethanol imports from CBI countries may be imported into the United States duty-free at quantities no greater than 7 percent of the previous federal fiscal year U.S. fuel ethanol consumption quantity (ending September 30). This means that fuel ethanol imports from CBI countries could amount to 620.5 million gallons in 2009 based on ethanol demand of 8.86 billion gallons between October 2007 and September 2008. See the following link for specific statute language relevant to the annual import limit that is duty-free: http://regulations.vlex.com/vid/import-investigations-ethyl-alcohol-fuel-22711676

CBI fuel ethanol imports totaled 273.4 million gallons during 2008. A more detailed description of ethanol imports from CBI countries in contained in the following report: *Ethanol Imports and the*

Caribbean Basin Initiative, Brent D. Yacobucci, CRS Report to Congress, Updated March 18, 2008. A link to that report is as follows: http://www.nationalaglawcenter.org/assets/crs/RS21930.pdf

[lxxiii] The Brazil Ministry of Agriculture sets the ratio of ethanol in low-level gasoline blends each year based on the market outlooks for both sugar and ethanol. The maximum blend limit is 26 percent by volume.

The Brazilian Ethanol Programme: Impacts on World Ethanol and Sugar Markets, Tatsuji Koizumi, Commodities and Trade Division of the Food and Agriculture Organization of the United Nations (FAO), June 24, 2003, page 2. A link to this document is as follows: ftp://ftp.fao.org/docrep/fao/006/ad430e/ad430e00.pdf

This working paper also contains a good summary of the history of Brazil's ethanol program.

[lxxiv] *Harmonized Tariff Schedule of the United States (2009) – Supplement 1*, United States International Trade Commission, July 1, 2009, subheading 2207.10.60, page 1006. Citation for the 2.5 percent ad valorem fee on undenatured ethyl alcohol intended for nonbeverage use in the United States.

Harmonized Tariff Schedule of the United States (2009) – Supplement 1, United States International Trade Commission, July 1, 2009, subheading 9901.00.50, page 2558. Citation for the secondary import tariff of 14.27 cents per liter or 54.08 cents per gallon (CPG) on ethyl alcohol intended for fuel use in the United States. A link to the Harmonized Tariff Schedule document is as follows: http://www.usitc.gov/publications/docs/tata/hts/bychapter/0910htsa.pdf

[lxxv] *Removal of U.S. Ethanol Domestic and Trade Distortions: Impact on U.S. and Brazilian Ethanol Markets*, Amani Elobeid and Simla Tokgoz, Center for Agricultural and Rural Development, Iowa State University, Working Paper 06-WP 427, October 2006 (Revised), page 22. A link to the document is as follows: http://www.card.iastate.edu/publications/DBS/PDFFiles/06wp427.pdf

The lower estimate of 2.4 percent U.S. ethanol price reduction is from the following Working Paper: *The Economics of U.S. Ethanol Import Tariffs with a Consumption Blend Mandate and Tax Credit*, Harry de Gorter and David R. Just, Department of Applied Economics and Management, Cornell University, Ithaca, New York, February 7, 2008, Table 2, page 24. Note that the 2.4 percent reduction of the U.S. ethanol price is for 2015 and is under a scenario of mandated ethanol use, removal of the import tariff, and retention of the 45 cpg ethanol blenders' tax credit. A link to this working paper is as follows:
http://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID1097106_code328474.pdf?abstractid=1024532&mirid=5

[lxxvi] *Perspectivas Para O Etanol No Brasil*, Empresa de Pesquisa Energética (EPE), October 3, 2008. A link to this document in Portuguese is as follows:
http://www.epe.gov.br/Petroleo/Documents/Estudos_28/Cadernos%20de%20Energia%20-%20Perspectiva%20para%20o%20etanol%20no%20Brasil.pdf

The EPE ethanol export forecast is from Graph 9 on page 33 of this report. The UNICA export estimate is from Table 7 on page 38 of the report.

[lxxvii] *Biofuels Roundup: Brazilian Ethanol Gets Japanese Boost*, Jeff St. John, Greentech Media, September 30, 2008. A link to the article is as follows: http://www.greentechmedia.com/articles/read/biofuels-roundup-brazilian-ethanol-gets-japanese-boost-1505/

The demand for Brazilian ethanol imports for Japan is estimated at up to 1.8 billion liters or 480 million gallons by 2010. *Japan's Ethanol Introduction and Outstanding Issues*, Japan's Institute of Energy Economics, October 2007, page 4. A link to this document is as follows:
http://eneken.ieej.or.jp/en/data/pdf/403.pdf

[lxxviii] The Lomita facility was averaging 22,300 barrels per day of ethanol receipts during 2007 according Kinder Morgan. See *Biofuels Houston Summit III* presentation, October 20-21, 2008, slide 20. A link to this presentation is as follows:
http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

Staff estimates that rail imports of fuel ethanol for all of Southern California totaled approximately 33,500 barrels per day during 2007. Total fuel ethanol demand in Southern California for that year was about 34,700 barrels per day.

[lxxix] Kinder Morgan PowerPoint presentation, January 28, 2010, slide 16. A link to the presentation is as follows:

http://www.kindermorgan.com/investor/presentations/2010_Analysts_Conf_06_Products_Pipes.pdf

[lxxx] Staff discussion concerning proposed project with company representatives.

[lxxxi] For a description of an ethanol transloading terminal operation (Norfolk Southern ethanol transloading facility in Alexandria, Virginia), refer to the following presentation: *Ethanol Transloading*,

City of Alexandria, Presentation to City Council, May 27, 2008. A link to this presentation is as follows: http://alexandriava.gov/special/transloading/docs/EthanolTransloadingPresentation052708.pdf

[lxxxii] *Biofuels Houston Summit III* presentation, Kinder Morgan, October 20-21, 2008, slide 20. A link to this presentation is as follows: http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[lxxxiii] *Renewable Fuel Terminal Infrastructure*, Rahul Iyer, Primafuel, California Energy Commission Workshop, April 14, 2009, slide 8. A copy of this presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/05-Lyer_Rahul_Primafuel_ENERGY COMMISSION_EnergyInfrastructureWorkshop.pdf

[lxxxiv] Kinder Morgan PowerPoint presentation, August 24, 2009, slides 13-14. A link to the presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-0824_workshop/presentations/05_KMP_Tobin.pdf

[lxxxv] "KMP Begins Commercial Operations of Ethanol Transportation on Central Florida Pipeline System," Kinder Morgan press release, December 2, 2008. A copy of the press release may be viewed at the following link: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1231520&highlight=

[lxxxvi] *Joint Integrated Energy Policy Report and Transportation Committee Workshop on Transportation Fuel Infrastructure Issues*, transcript, Ed Hahn comments, Kinder Morgan, April 14, 2009, pp. 201-4. A link to the transcript is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[lxxxvii] "POET Joins Magellan Midstream Partners to Assess Dedicated Ethanol Pipeline," Magellan Midstream Partners, L.P. press release, March 16, 2009. A link to this press release is as follows: http://www.magellanlp.com/news/2009/20090316_5.htm

[lxxxviii] *World Agricultural Supply and Demand Estimates*, United States Department of Agriculture, October 9, 2009, page 12. A link to the document is as follows: http://usda.mannlib.cornell.edu/usda/current/wasde/wasde-10-09-2009.pdf

[lxxxix] *USDA Agricultural Projections to 2018*, Report Number OCE-2009-1, February 2009, Table 8, page 33. A copy of the document may be accessed at the following link:

http://www.ers.usda.gov/Publications/OCE091/OCE091.pdf

[xc] Ibid., quote from page 18, "Projections for field crops reflect provisions of the Food, Conservation, and Energy Act of 2008 (2008 Farm Act), which are assumed to continue through the projection period. An important change in the 2008 Farm Act was the reduction in the maximum acreage enrollment in the

Conservation Reserve Program (CRP). Rather than the previous cap on enrollment of 39.2 million acres, the new farm legislation sets the maximum at 32 million acres, beginning on October 1, 2009. With CRP enrollment at 34.8 million acres on September 30, 2008, ***this policy change provides some additional cropland for potential use in production rather than tightening cropland availability over the projection period***."

[xci] Ibid. Table 7, page 32.

[xcii] Corn using irrigated water totaled 13.16 million acres in 2007, while non-irrigated corn amounted to 73.09 million acres. Since irrigated corn has a higher yield, the percentage of corn produced from irrigated acres is slightly higher, approximately 16.9 percent for the same year. *2007 Census of Agriculture*, United States Department of Agriculture, Table 32, page 26, updated September 2009. A link to the document is as follows:
http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_US/usv1.pdf

[xciii] Most recent complete year of fertilizer data for U.S. corn acres is 2005. Nitrogen application for fertilized corn was 130 pounds per acre in 1980 and 138 pounds per acre in 2005. *U.S. Fertilizer Use and Price*, USDA Economic Research Service, Table 10, updated November 20, 2008. A link to the data is as follows: http://www.ers.usda.gov/Data/FertilizerUse/Tables/FertilizerUse.xls

Corn yield in 1980 was 91.0 bushels per acre and 147.9 bushels per acre in 2005. *Crop Production Historical Track Records*, USDA, National Agricultural Statistics Service, April 2009, page 27. A link to the document is as follows: http://usda.mannlib.cornell.edu/usda/current/htrcp/htrcp-04-30-2009.pdf

[xciv] *Historical Perspectives On Vegetable Oil-based Diesel Fuels*, Gerhard Knothe, Inform, Volume 12, November 2001, pp. 1103-4. A link to this article is as follows:
http://www.biodiesel.org/resources/reportsdatabase/reports/gen/20011101_gen-346.pdf

[xcv] Ibid. page 1107.

[xcvi] Ibid. page 1105.

[xcvii] National Renewable Energy Laboratory, *Biodiesel Handling and Use Guide*, fourth edition, publication number NREL/TP-540-43672, revised January 2009, page 23. A link to the revised document is as follows: http://www.nrel.gov/docs/fy09osti/43672.pdf

[xcviii] National Renewable Energy Laboratory, *Survey of the Quality and Stability of Biodiesel and Biodiesel Blends in the United States in 2004*, publication number NREL/TP-540-38836, October 2004, pages 18, 49, and 50. A link to the survey is as follows: http://www.nrel.gov/docs/fy06osti/38836.pdf

[xcix] The $1-per-gallon volumetric biodiesel blenders credit originated in the JOBS Act of 2004 legislation. This portion of the act was intended to encourage increased biodiesel production, higher blending into

diesel fuel, and the creation of additional agricultural jobs. The following link to a National Biodiesel Board Issue Brief contains additional specifics and Internal Revenue Service provisions: http://www.biodiesel.org/news/taxincentive/Biodiesel%20Tax%20Credit%20NBB%20Issue%20Breif.pdf

[c] European Biodiesel Board press release, Figure II, page 2, July 15, 2009. A link to the press release is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202008%20prod%202009%20cap%20FINAL.pdf

[ci] The European Commission conducted a nine-month investigation and concluded that the application of countervailing and anti-dumping tariffs for U.S. biodiesel exports to Europe was necessary to "level the playing field" for European biodiesel producers. The new tariffs became effective on March 13, 2009. On July 1, 2009, the Council of the European Union adopted these provisions for a period of five years. A link to the countervailing tariff decision is as follows: http://register.consilium.europa.eu/pdf/en/09/st11/st11080.en09.pdf

The link to the anti-dumping tariff decision is as follows: http://register.consilium.europa.eu/pdf/en/09/st11/st11084.en09.pdf

[cii] However, some biodiesel producers and exporters soon realized that the addition of even small quantities of petroleum diesel fuel (approximately 1 percent by volume) enabled them to obtain the blenders credit for nearly all of the export volume. The increased exports of biodiesel originating from the United States prompted the decision by the European Union to impose sufficiently high off-setting tariffs to help ensure a more level playing field for their own biodiesel producers. A copy of the press release from the European Biodiesel Board is as follows: http://www.ebbeu.org/EBBpressreleases/PR%20B99%20publication%20definitive%20measures%20%20070709.pdf

[ciii] A link to a copy of the SWRCB regulatory action and Office of Administrative Law (OAL) approval are as follows: http://www.waterboards.ca.gov/water_issues/programs/ust/regulatory/biodiesel/oal_file2009_0521_02e.pdf

[civ] Valero Energy Corporation Comments on the Draft 2009 Integrated Energy Policy Report (IEPR) Docket No. 09-IEP-1K, Valero Energy Corporation, John Braeutigam, September 4, 2009, pp. 2-3. A link to this document is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-24_workshop/comments/2009-09-04_Valero_Energy_Corporation_TN-53150.PDF

[cv] Ibid., page 2.

[cvi] Ibid., page3.

[cvii] Conversion of waste oils (used cooking oil) to biodiesel has a carbon intensity value of 13.70 gCO2e/MJ. Conversion of tallow to renewable diesel fuel has a carbon intensity value of 27.70

gCO2e/MJ. California Air Resources Board, Modified Regulation Order, Table 7, page 44, posted July 20, 2009. A link to the document is as follows: http://www.arb.ca.gov/regact/2009/lcfs09/lcfsmodtxt.pdf

[cviii] Biodiesel magazine, plant list. A link to this information is as follows: http://www.biodieselmagazine.com/plant-list.jsp?country=USA&view=

[cix] Ibid.

[cx] *EU Biodiesel Potential*, Raffaello Garofalo, RSB Consultation, Europe Stakeholder Outreach Meeting, Brussels, March 19, 2009, slide 8. A link to this presentation is as follows: http://cgse.epfl.ch/webdav/site/cgse/shared/Biofuels/Regional%20Outreaches%20&%20Meetings/2009/Europe%2009/Raffaello%20Garofalo%20-%20EBB.pdf

[cxi] European Biodiesel Board press release, Figure V, July 15, 2009, page 3. A link to this document is as follows: http://www.ebb-eu.org/EBBpressreleases/EBB%20press%20release%202008%20prod%202009%20cap%20FINAL.pdf

[cxii] 403 million gallons based on B10 levels for total diesel fuel demand of 4.03 billion gallons per year by 2022 and 806 million gallons based on B20.

[cxiii] Estimates from Cybus Capital Markets LLC range from 2 cents per gallon (cpg) for pipeline transportation, 5 cpg via barge, 10 cpg via rail, and 20 cpg via tanker truck. *Biofuels Houston Summit III* presentation, Kinder Morgan, October 20-21, 2008, slide 23. A link to this presentation is as follows: http://www.braziltexas.org/attachments/contentmanagers/1/Kinder%20Morgan%20BF2008.pdf

[cxiv] "KMP Completes First Commercial Shipment of Biodiesel in U.S. on Plantation Pipe Line," Kinder Morgan press release, June 30, 2009.A link to this press release is as follows: http://phx.corporate-ir.net/phoenix.zhtml?c=119776&p=irol-newsArticle&ID=1303436&highlight=

[cxv] U.S. Energy Information Administration, *2008 Annual Energy Report*, Table 6.5. Natural Gas Consumption by Sector, 1949-2007. http://www.eia.doe.gov/emeu/aer/txt/ptb0605.html

[cxvi] U.S. Department of Energy via: http://www.fueleconomy.gov/feg/bifueltech.shtml

[cxvii] All carbon intensity values come from the ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.*

[cxviii] For this discussion, dual fuel CNG/gasoline vehicles are considered as CNG vehicles in vehicle counts. All vehicle counts come via the DMV database.

[cxix] Information from Fueleconomy.com: http://www.fueleconomy.gov/feg/bifueltech.shtml

[cxx] *State Alternative Fuels Plan – AB 1007 Report* - Docket # 06-AFP-1, http://www.energy.ca.gov/ab1007/index.html

[cxxi] http://www.socalgas.com/business/ngv/refueling.html

[cxxii] http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/fueling/

[cxxiii] Southern California Gas Company: http://www.socalgas.com/business/ngv/homefueling.html

[cxxiv] Testimony of Michael Eaves at the April 14, 2009, Joint Committee Workshop, California Energy Commission at http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[cxxv] All carbon intensity values come from the ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.*

[cxxvi] ARB's *Proposed Regulation to Implement the Low Carbon Fuel Standard: Volume 1.* Table ES-10

[cxxvii] Testimony of Robert Graham, Southern California Edison, at the April 14, 2009, Joint Committee Workshop, California Energy Commission at: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[cxxviii] A recent study recently completed by the Government Accountability Office (GAO) describes the various challenges facing increased use of PHEVs, as well as elaborating on specific developments that would be necessary for PHEVs to be competitive. Government Accountability Office, *Plug-in Vehicles Offer Potential Benefits, but High Costs and Limited Information Could Hinder Integration into the Federal Fleet*, GAO-09-493, June 2009; available from http://www.gao.gov/new.items/d09493.pdf

[cxxix] Ibid.

[cxxx] Ibid.

[cxxxi] Testimony of Chelsea Sexton, Lightning Rod Foundation, at the April 14, 2009, Joint Committee Workshop, California Energy Commission at

http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf

[cxxxii] Ibid.

[cxxxiii] Energy Information Administration website: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html

[cxxxiv] Ohnsman, Alan and Kiyori Ueno, *Nissan Plans to Add Electric Vehicles to U.S. Factory*, Bloomberg.com

[cxxxv] The charging connector for plug-in electric vehicles completed Underwriters Laboratories (UL) certification testing during June 2009. *Underwriters Laboratories Approves SAE J1772 Charging Plug*, Sam Abuelsamid, AutoBlogGreen, June 28, 2009; available from http://www.autobloggreen.com/2009/06/28/underwriters-laboratories-approves-sae-j1772-charging-plug/

[cxxxvi]AEO 2009, Figure 8: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html

[cxxxvii] EIA: http://www.eia.doe.gov/kids/energyfacts/sources/IntermediateHydrogen.html

[cxxxviii] http://www.cafcp.org/sites/files/Action%20Plan%20FINAL.pdf

[cxxxix] http://www.hydrogencarsnow.com/chevy-equinox-fuel-cell-suv.htm and http://www.daimler.com/dccom/0-5-1200805-1-1201974-1-0-0-1201138-0-0-135-0-0-0-0-0-0-0-0.html

[cxl] Testimony of John Mough, California Department of Food and Agriculture, Division of Weights and Measures, at the April 14, 2009, Joint Integrated Energy Policy Report and Transportation Committee Workshop.

[cxli] According to the California Division of Measurement Standards: *National fuel sampling and test procedures for hydrogen fuel have also not been established. The SAE International and ASTM International are taking the lead in the development of national sampling and test procedures for hydrogen but their work is far from finished. It is hoped that this work will be completed before hydrogen fuel cell vehicles become readily available to the general public. However, DMS will begin its own research on sampling procedures and analytical methodology, in the event that California needs to determine compliance with its hydrogen fuel quality standards.*

DMS recognizes that establishing a comprehensive set of accuracy and advertising standards for commercially available hydrogen fuel is a critical first step in the development of a fair and competitive marketplace in the California Hydrogen Highway infrastructure. Creating codes that specify dispenser accuracy requirements will *allow consumers to obtain a full measure at the greatest value. Defining a legal method of sale and advertising requirements is the most practical and efficient way to ensure that a) consumers can make value comparisons between competing retail service stations, b) that sellers will advertise and deliver hydrogen using a single unit of measurement, and c) that a level playing field for competing businesses is established.*

Source of comments: California Department of Food and Agriculture, Division of Measurement Standards, Docket No. 09-IEP-1K comment letter, September 3, 2009, pp 2-3.

[cxlii] Testimony of Michael Coates, Mightycomm, on behalf of Daimler AG, at the April 14, 2009, Joint Integrated Energy Policy Report and Transportation Committee Workshop.

[cxliii] The California State Offshore area includes all submerged lands within 3 miles of the state boundary. Federal Outer Continental Shelf (OCS) waters extend from this 3-mile California offshore boundary line to a 200-mile limit from the California state land boundary. More details concerning these limits and other OCS boundaries can be obtained at the following link:
http://www.mms.gov/ooc/newweb/QandA.htm

[cxliv] As of July 2009, the Big West refinery in Bakersfield is temporarily idled as a consequence of the Chapter 11 filing and subsequent business decisions of the parent company, Flying J. It is assumed that this facility will be purchased by another company and resume operations no later than January 2011.

[cxlv] California is one of the seven states contained in the western geographic subsection of the United States that comprise Petroleum Administration for Defense District V or PAD District V. The EIA revised Reference Case forecast shows refinery distillation capacity growing at an average rate of 0.47 percent per year between 2008 and 2030 for PAD District V. AEO 2009 revised Reference Case, Table 102, April 2009. A link to the table is as follows:
http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/sup_ogc.xls

[cxlvi] *Southern California Crude Oil Outlook Summary Update*, Baker & O'Brien, April 2009. A link to their presentation is as follows: http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-2/02-Sirur_Dileep_Southern_CA_Crude_Oil_Outlook.pdf

[cxlvii] Over the last three years (2006 through 2008), the portion of crude oil waterborne receipts into California that have been imported through marine terminals in Southern California has averaged 59.1 percent of the total waterborne crude oil imports to the state.

[cxlviii] Additional information concerning marine vessel tanker definitions and sizes can be obtained by reviewing a presentation by Pacific Energy Partners at the following link:
http://www.pacificenergypier400.com/pdfs/TANKERS/TankerBusEmissions.pdf

Another resource that includes descriptions and definitions for all types of marine tankers (both crude oil and petroleum products) can be viewed at the following link:
http://www.globalsecurity.org/military/systems/ship/tanker-types.htm

[cxlix] The crude oil import facility proposed by Pacific Energy Partners has a design capacity of 4 million barrels of crude oil storage and a daily import capability of up to 250,000 barrels per day of crude oil. These storage capacities and throughput design equate to 1 million barrels of storage per 23 million barrels of imports per year. Additional project information is located at the following link: http://www.pacificenergypier400.com/index2.php?id=3

[cl] *Survey of Available Data on OCS Resources and Identification of Data Gaps*, U.S. Department of Interior, Mineral Management Services, Report MMS 2009-015, May 2009, Appendix C, Table C-1, page C-2; available from http://www.doi.gov/ocs/report.pdf; Internet; accessed on August 2, 2009.

An historical assessment of crude oil reserves and production in the most active OCS region, the Gulf of Mexico, is contained in the following report: *Estimated Oil and Gas Reserves Gulf of Mexico, December 31, 2005*, U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, May 2009, Table 6, page 45; available from http://www.gomr.mms.gov/PDFs/2009/2009-022.pdf; Internet; accessed on August 2, 2009.

[cli] Ibid, page 5.

[clii] A link to EIA's assessment is as follows: http://www.eia.doe.gov/oiaf/aeo/otheranalysis/ongr.html

[cliii] A link to the MMS press release is as follows: http://www.mms.gov/ooc/press/2008/pressDOI0730.htm

[cliv] A list and location of all of the offshore crude oil and natural gas production platforms in state and federal waters off the coast of California is described by the Mineral Management Services (MMS), a division of the Department of the Interior. A link to this information is as follows: http://www.mms.gov/omm/Pacific/offshore/platforms/platformintro.htm

[clv] Energy Commission estimate based on information obtained from California State Lands Commission and County of Santa Barbara presentations. The CSLC staff estimate of Tranquillon Ridge production is more conservative than the one Aspen prepared on behalf of the County of Santa Barbara. CSLC estimate from the Commission Informational Hearing, Tranquillon Ridge Field, January 6, 2009. A link to the presentation is as follows: http://archives.slc.ca.gov/Meeting_Summaries/2009_Documents/01-06-09/ITEMS_AND_EXHIBITS/R01Exhibit.pdf

The Aspen estimate was obtained from Figure 2-3 of the Final EIR released on March 27, 2008. A link to the document is as follows: http://www.countyofsb.org/energy/documents/projects/TranqRidgeFinalEIR/index.htm

Energy Commission staff analysis of these two information resources has derived estimated incremental cumulative crude oil production from Tranquillon Ridge of between 60 and 110 million barrels for the first 12 years of the project.

[clvi] On July 24, 2009, the California state Assembly defeated by a vote of 43-28 an agreement that had been approved by the state Senate to permit Plains All American to proceed with their Tranquillon Ridge Project. "California's Expanded Drilling Plan Delayed But Not Dead," Cassandra Sweet, *Dow Jones*

Newswires, July 28, 2009, reprinted by Rigzone; available from
http://www.rigzone.com/news/article.asp?a_id=78651

The Assembly later undertook an unusual move to vote in favor of expunging the roll-call votes on AB 23 for removing the identity of Assembly members who voted for, against, or did not cast a vote on this measure. However, a full accounting of the official roll-call is available from other sources. See: "Erase the Cowardice," *San Francisco Chronicle*, Editorial, August 3, 2009; available from
http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2009/08/03/ED7E192A9L.DTL#ixzz0N7rq0uAZ

[clvii] California gasoline demand has continuously declined since peaking in 2004 at 15.91 billion gallons. During the first four months of 2009, gasoline demand is down 2.1 percent compared to the same period in 2008. If gasoline demand in 2009 turns out to be lower than 2008, the five years of consecutive decline in demand is something that has never happened since the end of World War II. The only other period of four consecutive years of declining gasoline demand was between 1978 and 1982.

[clviii] In 2007, demand for transportation fuels was 22.91 billion gallons (15.66 billion for gasoline, 3.81 billion for diesel fuel, and 3.45 billion for jet fuel). Total demand for these three fuels had declined to 21.50 billion gallons in 2008 (14.92 billion gallons for gasoline, 3.43 billion for diesel fuel, and 3.15 billion for jet fuel).

[clix] As of July 2009, the Big West refinery in Bakersfield is temporarily idled as a consequence of the Chapter 11 filing and subsequent business decisions of the parent company, Flying J. It is assumed that this facility will be purchased by another company and resume operations no later than January 2011.

[clx] California is one of the seven states contained in the western geographic subsection of the United States that comprise Petroleum Administration for Defense District V or PAD District V. The EIA revised Reference Case forecast shows refinery distillation capacity growing at an average rate of 0.47 percent per year between 2008 and 2030 for PAD District V. AEO 2009 revised Reference Case, Table 102, April 2009. A link to the table is as follows:
http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/sup_ogc.xls

[clxi] The forecast of revenue passenger enplanements (boarding of aircraft by paying passengers) by FAA for individual states was used as a starting point. Average fuel use per enplaned passenger was then calculated for historical periods. Future fuel use per enplaned passenger was then adjusted over the forecast period to reflect improvements in fuel economy. *FAA Aerospace Forecast Fiscal Years 2009–2025*, Federal Aviation Administration (FAA), April 2009; available from
http://www.faa.gov/data_research/aviation/aerospace_forecasts/2009-2025/media/2009%20Forecast%20Doc.pdf

The data used to assess improvements in fuel economy were obtained from Table 22 of this publication. A link to Tables 1 through 22 is available from
http://www.faa.gov/data_research/aviation/aerospace_forecasts/2009-2025/media/Web%20Air%20Carrier%202009.xls

[clxii] This region of the United States includes the states of Arizona and Nevada. A map of all of the states in this specific census region is available from
http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf

[clxiii] *Supplemental Tables to the Annual Energy Outlook 2009, Updated Reference Case with ARRA*, Energy Information Administration, April 2009, Table 8 available from http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/arra/excel/suptab_8.xls

[clxiv] *Supplemental Tables to the Annual Energy Outlook 2009, Low Oil Price Case*, Energy Information Administration, March 2009, Table 8 available from http://www.eia.doe.gov/oiaf/aeo/supplement/lp/excel/suptab_8.xls

[clxv] Kinder Morgan has already approved an expansion of the CalNev system between Colton and Las Vegas from 158 thousand barrels per day (TBD) to 200 TBD. Due to the recent downturn in demand and reduced forecasts over the near and mid-term periods, the company has decided to push off commencement of construction to a later date. *Kinder Morgan/SFPP, L.P. Pipeline System*, Ed Hahn, Kinder Morgan Energy Partners, L.P., April 14, 2009 presentation, slide 12 available from http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/presentations/Day-1/14-Hahn_Ed_Renewable_Fuels_and_Pipeline_Issues.pdf

[clxvi] The Holly Energy Partners project involves constructing a petroleum product pipeline from Salt Lake City, Utah to Las Vegas, Nevada. The pipeline would have an initial capacity of 62,000 barrels per day that could be operational by the end of 2010.

[clxvii] *Chevron Energy and Hydrogen Renewal Project*, Draft Environmental Impact Report, State Clearinghouse No. 2005072117, City of Richmond Project No. 1101974, Volume 1, pp. 3-32 to 3-34 available from http://www.ci.richmond.ca.us/DocumentView.aspx?DID=2729

[clxviii] Ibid., page 1-1.

[clxix] Chevron Richmond Refinery Energy and Hydrogen Renewal Project, Chevron U.S.A., Inc. available from http://www.chevron.com/products/sitelets/richmond/renewal/

[clxx] “Big West Supports Alternative D For the Clean Fuels Project,” Big West of California press release, September 19, 2008, page 2, available from http://www.bigwestca.com/bigwest/ShowDoc/BEA+Repository/bigwestPortal/bigwestDesktop/1_HomePage/news/news_8/pr8

[clxxi] “Flying J Files to Reorganize Under Chapter 11,” Flying J press release, December 22, 2008 available from http://www.flyingj.com/flyingjPortalWebProject/ShowDoc/BEA+Repository/flyingjPortal/flyingjDesktop/2_CompanyBook/3_PressPage/files/pr15/5

[clxxii] Flying J press release, February 2, 2010. A link to the press release is as follows:

http://www.flyingj.com/flyingjPortalWebProject/ShowDoc/BEA+Repository/flyingjPortal/flyingjDesktop/2_CompanyBook/3_PressPage/files/pr18

[clxxiii] A link to the UNEV pipeline construction schedule information is as follows:

http://www.unevpipeline.com/default.htm

[clxxiv] UNEV update from its website available from http://www.unevpipeline.com/

[clxxv] *CALCARS: The California Conventional and Alternative Fuel Response Simulator, A Nested Multinomial Logit Vehicle Demand and Choice Model*, Chris Kavalec, Demand Analysis Office, California Energy Commission, April 1996. A link to this paper that describes in detail the CALCARS model is as follows: http://www.energy.ca.gov/papers/CEC-999-1996-007.PDF

[clxxvi] All prices used in this work are in 2008 dollars, using the November 17, 2008, California Energy Commission deflator series from Moody's Economy.com unless specifically stated otherwise.

[clxxvii] The subset of premium light sweet oil constitutes a relatively small percentage of the oil actually refined in the United States or California, but prices for it are those most commonly referred to in the media.

[clxxix] Scenario Analyses of California's Electricity System: Preliminary Results for the *2007 Integrated Energy Policy Report*, Appendix H-3; June 2007; Energy Commission-200-2007-010-SD-AP.

[clxxx] From the February 10, 2009, Energy Commission staff workshop; can be found at http://www.energy.ca.gov/2009publications/CEC-600-2009-001/ENERGY COMMISSION-600-2009-001-SF.PDF.

[clxxxi] These growth rates are consistent with guidance and forecasts provided by the Demand Analysis Office of the Energy Commission.

Attachment 23

Attachment 23. All Publicly Available Data for Gas Oil Density and Sulfur Content, Compiled by CBE in April 2014, with Selected Crude Oil Assay Data.

			Assay	Whole Crude *d* and *S*		Gas Oil Boiling Point Data		Gas Oil *d* and *S*	
Crude Name	Bitumen Oil?	Source	Date	Density kg/m^3	Sulfur kg/m^3	Cut ºC	Cut ºF	Density kg/m^3	Sulfur kg/m^3
Ormen Lang	No	Norway--Statoil	2010	737	0.04	350-370		836	0.23
Beatrice	No	United Kingdom--BP	2002	836	0.50	342-369		838	0.42
Bach Ho	No	Viet Nam--Oil & Gas Journal	1999	832	0.33		648-696	840	0.28
Jacky	No	United Kingdom--BP	2009	830	0.50	342-369		840	0.43
Ormen Lang	No	Norway--Statoil	2010	737	0.04	370-450		847	0.36
Njord	No	Norway--Statoil	2008	794	0.38	320-375		850	0.59
Agbami	No	Nigeria--Statoil	2011	788	0.39	350-370		857	0.84
Bach Ho	No	Viet Nam--Oil & Gas Journal	1999	832	0.33		696-948	860	0.51
Magallanes	No	Chile--Oil & Gas Journal	1997	837	0.84		660-800	862	1.21
Beatrice	No	United Kingdom--BP	2002	836	0.50	369-509		864	0.59
Jacky	No	United Kingdom--BP	2009	830	0.50	369-509		864	0.66
Azeri-Ceyhan	No	Ceyhan--BP		841	1.35	342-369		865	1.80
Alvheim Blend	No	Norway--Statoil	2010	843	1.26	350-370		866	1.74
Azeri Light	No	Azerbaijan--Statoil	2005	851	1.28	350-370		867	1.21
Azeri BTC	No	Azerbaijan--Statoil	2012	843	1.18	350-370		867	1.23
Statfjord Blend	No	Norway--Statoil	2010	827	1.82	320-375		868	2.40
Minas	No	Indonesia--Oil & Gas Journal	1997	850	0.85		650-1049	868	1.09
Varg	No	Norway--Statoil	2005	835	1.90	320-375		869	2.51
Njord	No	Norway--Statoil	2008	794	0.38	375-420		869	0.82
Eocene	No	Saudi-Kuwait Partitioned Zone--Chevron	2011	940	43.0	260-340	500-650	870	20.5
Cossack	No	Australia--BP	2000	789	0.36	342-369		870	0.69
Ekofisk	No	Norway--BP	2011	838	1.59	342-369		871	1.95
Ekofisk	No	Norway--Statoil	2011	832	1.83	350-370		872	2.22
Norne Blend	No	Norway--Statoil	2009	862	1.79	320-375		873	2.06
Plutonio	No	Angola--BP	2010	859	3.18	342-369		874	3.16
Murban	No	Abu Dhabi--BP	2007	824	6.51	342-369		875	13.0
Rabi Light	No	Gabon--Total	2012	846	0.94	375-550		875	1.05
Taching	No	China--Oil & Gas Journal	1997	864	0.86		650-1049	875	0.75
Rabi Light	No	Gabon--Total	2012	846	0.94	375-565		876	1.14
Skarv	No	Norway--BP	2010	844	2.87	342-369		877	3.90
Hibernia Blend	No	Newfoundland--Statoil	2007	849	3.82	350-370		878	3.77
Forties Blend	No	United Kingdom--BP	2011	831	6.56	342-369		879	8.20
Zakum	No	Abu Dhabi--BP	2000	826	8.42	342-369		879	16.1
Alvheim Blend	No	Norway--Statoil	2010	843	1.26	370-450		880	1.84
Gulf of Suez	No	Egypt--BP	2008	869	12.2	342-369		881	12.4
Terra Nova	No	Newfoundland--Statoil	2005	859	4.30	350-370		881	3.97
Forties Blend	No	United Kingdom--Statoil	2012	831	6.56	350-370		881	8.28
Nkossa	No	Congo--Total	2010	825	0.46	375-550		882	0.71
Nkossa	No	Congo--Total	2010	825	0.46	375-565		882	0.71
Nkossa	No	Congo--Total	2010	825	0.46	400-565		882	0.71
Girassol	No	Angola--Statoil	2009	877	2.98	350-370		882	2.61
Varg	No	Norway--Statoil	2005	835	1.90	375-420		882	2.57
Bach Ho	No	Viet Nam--Oil & Gas Journal	1999	832	0.33		948-1022	882	0.71
Oseberg Blend	No	Norway--Statoil	2006	836	2.29	320-375		883	2.97
Asgard Blend	No	North Sea--Statoil	2012	787	1.30	375-420		883	3.57
Girassol	No	Angola--BP	2010	877	3.68	342-369		883	3.59
Saxi Blend	No	Angola--BP	2010	857	2.23	342-369		883	2.60

Volve	No	Norway--Statoil	2008	877	15.1	320-375		883	15.8
Thunder Horse	No	USA--BP	2010	857	6.26	342-369		884	7.03
Troll Blend	No	Norway--Statoil	2011	845	1.18	320-375		884	1.46
Agbami	No	Nigeria--Statoil	2011	788	0.39	370-450		884	1.24
Draugen	No	Norway--Statoil	2002	826	1.21	320-375		884	1.64
Galeota Mix	No	Trinidad and Tobago	2011	812	1.14	342-369		884	3.49
Umm Shaif	No	Das Island--BP	2000	839	11.0	342-369		886	17.8
Norne Blend	No	Norway--Statoil	2009	862	1.79	375-420		887	2.15
Njord	No	Norway--Statoil	2008	794	0.38	420-525		887	1.19
Hidra	No	Argentina--Total	2007	772	0.39	375-550		887	1.15
Kissanje	No	Angola--BP	2006	873	3.23	342-369		887	3.19
Cossack	No	Australia--BP	2000	789	0.36	369-509		888	0.98
Azeri Light	No	Azerbaijan--Statoil	2005	851	1.28	370-450		888	1.39
Azeri BTC	No	Azerbaijan--Statoil	2012	843	1.18	370-450		888	1.42
Southern Green Canyon	No	USA Louisiana--BP	2009	886	20.4	342-369		888	15.7
Foinhaven	No	United Kingdom--BP	2010	898	3.50	342-369		889	3.22
Poseidon	No	USA--BP	2009	877	14.5	342-369		889	12.0
Hidra	No	Argentina--Total	2007	772	0.39	375-565		889	1.24
Saxi Batuque Blend	No	Norway--Statoil	2011	855	2.22	350-370		889	2.39
Kissanje	No	Angola--Statoil	2011	871	3.31	350-370		889	3.09
Statfjord Blend	No	Norway--Statoil	2010	827	1.82	375-420		889	2.79
Sauces	No	Argentina--Oil & Gas Journal	1997	845	2.45		660-850	891	2.98
Hidra	No	Argentina--Total	2007	772	0.39	400-565		891	1.34
Ekofisk	No	Norway--Statoil	2011	832	1.83	370-450		891	2.56
Basra Light	No	Iraq--BP	2009	875	25.5	342-369		891	26.3
West Texas	No	USA Texas--Oil & Gas Journal	1997	824	2.72		650-1049	891	3.56
Beatrice	No	United Kingdom--BP	2002	836	0.50	509-550		892	0.87
Jacky	No	United Kingdom--BP	2009	830	0.50	509-550		892	0.96
Mondo	No	Angola--BP	2008	877	4.12	342-369		893	4.19
Gimboa	No	Angola--Statoil	2009	902	5.05	350-370		893	3.57
Schiehalion	No	United Kingdom--BP	2010	903	4.15	342-369		893	3.66
Mars	No	USA Louisiana--BP	2008	882	18.1	342-369		894	15.5
Mondo	No	Angola--Statoil	2008	876	3.68	350-370		894	3.34
Hungo Blend	No	Angola--Statoil	2008	885	5.66	350-370		894	4.92
Azeri-Ceyhan	No	Ceyhan--BP		841	1.35	369-509		895	1.82
Magallanes	No	Chile--Oil & Gas Journal	1997	837	0.84		800-1000	895	1.07
Alvheim Blend	No	Norway--Total	2011	845	1.61	375-550		895	2.42
Schiehalion Blend	No	United Kingdom--Statoil	2010	903	4.15	350-370		895	3.65
Asgard Blend	No	Norway--Total	2012	786	1.27	375-550		895	4.56
Hungo	No	Angola--BP	2008	883	5.47	342-369		895	5.11
Alvheim Blend	No	Norway--Total	2011	845	1.61	375-565		896	2.51
Hibernia Blend	No	Newfoundland--Statoil	2007	849	3.82	370-450		896	4.84
Shengli	No	China--Oil & Gas Journal	1997	906	9.15		650-1049	896	6.73
Hoops	No	USA--BP	2006	867	10.1	342-369		896	10.6
Badak	No	Indonesia--Total	2009	830	0.50	375-550		897	1.08
Alvheim Blend	No	Norway--Total	2011	845	1.61	400-565		897	2.60
Girassol	No	Angola--Statoil	2009	877	2.98	370-450		897	3.10
Asgard Blend	No	Norway--Total	2012	786	1.27	375-565		897	4.66
Murban	No	Abu Dhabi--BP	2007	824	6.51	369-509		897	12.3
Badak	No	Indonesia--Total	2009	830	0.50	375-565		898	1.08
Badak	No	Indonesia--Total	2009	830	0.50	400-565		898	1.08

Alvheim Blend	No	Norway--Statoil	2010	843	1.26	450-500		898	2.25
Palanca	No	Angola--Total	2005	840	1.76	375-565		898	2.60
East Texas	No	USA Texas--Oil & Gas Journal	1997	834	2.50		650-1049	898	3.54
Dalia	No	Angola--BP	2007	912	4.53	342-369		899	4.04
Ekofisk	No	Norway--BP	2011	838	1.59	369-509		899	2.48
Badak	No	Indonesia--Total	2009	830	0.50	375-580		899	1.08
Asgard Blend	No	Norway--Total	2012	786	1.27	375-580		899	4.85
Terra Nova	No	Newfoundland--Statoil	2005	859	4.30	370-450		899	5.03
Alaskan North Slope	No	USA Alaska--BP	2010	865	8.04	342-369		899	9.17
Skarv	No	Norway--BP	2010	844	2.87	369-509		899	4.67
Palanca	No	Angola--Total	2005	840	1.76	375-580		900	2.70
Dalia	No	Angola--Statoil	2009	915	4.67	350-370		900	3.76
Asgard Blend	No	North Sea--Statoil	2012	787	1.30	420-525		900	4.76
Pazflor	No	Angola--BP	2012	900	3.69	342-369		900	3.39
Es Sider	No	Libya--Total	2007	841	3.11	375-550		901	3.51
Murban	No	UAE--Total	2013	822	6.11	400-580		901	12.8
Plutonio	No	Angola--BP	2010	859	3.18	369-509		901	3.93
Dalia	No	Angola--BP	2010	914	4.66	342-369		901	4.29
Troll Blend	No	Norway--Statoil	2011	845	1.18	375-420		901	1.87
Galeota Mix	No	Trinidad and Tobago	2011	812	1.14	369-509		901	4.22
Draugen	No	Norway--Statoil	2002	826	1.21	375-420		902	2.02
Tangguh Condensate	No	Indonesia--BP	2010	805	0.32	369-509		902	1.15
Norne Blend	No	Norway--Statoil	2009	862	1.79	420-525		902	2.64
Varg	No	Norway--Statoil	2005	835	1.90	420-525		902	3.27
Mixed Sweet Blend	No	Canada--Crude Monitor	2011	826	3.39	343-527		903	4.73
Ekofisk	No	Norway--Total	2011	832	1.83	375-550		903	2.89
Es Sider	No	Libya--Total	2007	841	3.11	375-565		903	3.79
Asgard Blend	No	Norway--Total	2012	786	1.27	400-580		903	5.15
Forties Blend	No	United Kingdom--Statoil	2012	831	6.56	370-450		903	9.93
Oseberg Blend	No	Norway--Statoil	2006	836	2.29	375-420		904	3.59
Saturno Blend	No	Angola--BP	2013	900	7.47	342-369		904	7.08
El Sharara	No	Libya--Total	2003	810	0.57	375-550		904	1.54
El Sharara	No	Libya--Total	2003	810	0.57	375-580		904	1.54
Akpo Blend	No	Nigeria--Total	2011	797	0.48	375-550		904	1.63
Marib Light	No	Yemen--Total	2007	809	1.38	375-550		904	3.44
Syrian Light	No	Syria--Total	2010	834	5.67	375-550		904	8.50
Zakum	No	Abu Dhabi--BP	2000	826	8.42	369-509		904	15.7
El Sharara	No	Libya--Total	2003	810	0.57	375-565		905	1.54
Cabinda	No	Angola--Total	2011	864	1.33	375-550		905	1.72
Gullfaks	No	Norway--Total	2008	837	2.17	375-550		905	3.89
Cabinda	No	Angola--Total	2011	864	1.33	375-565		906	1.81
Troll	No	Norway--Total	2011	845	1.27	375-580		906	2.27
Saxi Batuque Blend	No	Norway--Statoil	2011	855	2.22	370-450		906	3.00
Ekofisk	No	Norway--Total	2011	832	1.83	375-565		906	3.08
Ekofisk	No	Norway--Total	2011	832	1.83	400-565		906	3.08
Kissanje	No	Angola--Statoil	2011	871	3.31	370-450		906	3.90
Syrian Light	No	Syria--Total	2010	834	5.67	375-565		906	8.70
Murban	No	UAE--Total	2013	822	6.11	375-550		906	12.5
Murban	No	UAE--Total	2013	822	6.11	375-550		906	12.5
Cano Limon	No	Colombia--Oil & Gas Journal	1997	871	4.18		650-1049	906	5.88
Gulf of Suez	No	Egypt--BP	2008	869	12.2	369-509		906	14.3

Akpo Blend	No	Nigeria--Total	2011	797	0.48	375-565		907	1.72
Azeri Light	No	Azerbaijan--Statoil	2005	851	1.28	450-500		907	1.80
Akpo Blend	No	Nigeria--Total	2011	797	0.48	400-565		907	1.81
Troll	No	Norway--Total	2011	845	1.27	375-565		907	2.27
Brent	No	United Kingdom--Total	2006	834	3.50	375-550		907	5.71
Syrian Light	No	Syria--Total	2010	834	5.67	375-580		907	8.89
Murban	No	UAE--Total	2013	822	6.11	375-565		907	12.7
Murban	No	UAE--Total	2013	822	6.11	375-565		907	12.7
Foinhaven	No	United Kingdom--BP	2010	898	3.50	369-509		907	3.58
Statfjord Blend	No	Norway--Statoil	2010	827	1.82	420-525		908	3.57
El Sharara	No	Libya--Total	2003	810	0.57	400-565		908	1.54
Azeri BTC	No	Azerbaijan--Statoil	2012	843	1.18	450-500		908	1.82
Cabinda	No	Angola--Total	2011	864	1.33	375-580		908	1.82
Troll	No	Norway--Total	2011	845	1.27	375-550		908	2.36
Alvheim Blend	No	Norway--Statoil	2010	843	1.26	500-550		908	2.91
Schiehalion Blend	No	United Kingdom--Statoil	2010	903	4.15	370-450		908	4.02
Gullfaks	No	Norway--Total	2008	837	2.17	375-565		908	4.09
Syrian Light	No	Syria--Total	2010	834	5.67	400-565		908	8.90
Polvo	No	Brazil--BP	2009	932	10.5	342-369		908	8.87
Troll	No	Norway--Total	2011	845	1.27	400-565		909	2.36
Ekofisk	No	Norway--Statoil	2011	832	1.83	450-500		909	3.23
Brent	No	United Kingdom--Total	2006	834	3.50	375-565		909	5.91
Murban	No	UAE--Total	2013	822	6.11	375-580		909	12.8
Murban	No	UAE--Total	2013	822	6.11	375-580		909	12.8
Saxi Blend	No	Angola--BP	2010	857	2.23	369-509		909	2.98
Oriente	No	Ecuador--Oil & Gas Journal	1997	868	8.42		650-1049	909	11.1
Nemba	No	Angola--Total	2008	826	1.82	375-550		911	3.46
Mondo	No	Angola--Statoil	2008	876	3.68	370-450		911	4.04
Girassol	No	Angola--BP	2010	877	3.68	369-509		911	4.07
Forties Blend	No	United Kingdom--BP	2011	831	6.56	369-509		911	10.8
Volve	No	Norway--Statoil	2008	877	15.1	375-420		911	18.5
Bayou Choctaw Sweet	No	USA SPR--DOE	2000	845	3.04		650-1050	912	5.20
Girassol	No	Angola--Total	2009	877	2.98	375-565		912	3.74
Oseberg	No	Norway--Total	2010	835	2.09	375-550		912	4.01
Sauces	No	Argentina--Oil & Gas Journal	1997	845	2.45		850-1038	912	4.21
Cabinda	No	Angola--Total	2011	864	1.33	400-580		913	1.92
Medanito	No	Argentina--Total	2009	860	4.05	375-550		913	5.20
Mandji	No	Gabon--Total	2010	876	8.76	375-550		913	9.13
Sour Light Edmonton	No	Canada--Crude Monitor	2011	824	8.16	343-527		913	12.1
Clair	No	United Kingdom--BP	2010	912	4.29	342-369		913	4.18
West Hackberry Sweet	No	USA SPR--DOE	2001	838	2.68		650-1050	913	4.75
Troll Blend	No	Norway--Statoil	2011	845	1.18	420-525		914	2.31
Calypso	No	Trinidad and Tobago	2008	871	5.14	375-550		914	5.58
Alba	No	United Kingdom--Statoil	2013	936	11.8	350-370		914	7.88
Murban	No	UAE--Total	2013	822	6.11	400-580		914	13.0
Bryan Mound Sweet	No	USA SPR--DOE	2000	845	2.79		650-1050	914	4.66
Thunder Horse	No	USA--BP	2010	857	6.26	369-509		915	8.24
Schiehalion	No	United Kingdom--BP	2010	903	4.15	369-509		915	4.22
Kissanje	No	Angola--BP	2006	873	3.23	369-509		915	4.03
Brass River	No	Africa--Total	2012	824	1.48	375-550		915	3.39
Nemba	No	Angola--Total	2008	826	1.82	375-565		915	3.57

Girassol	No	Angola--Total	2009	877	2.98	375-550		915	3.93
Dalia	No	Angola--Statoil	2009	915	4.67	370-450		915	4.51
Medanito	No	Argentina--Total	2009	860	4.05	375-565		915	5.40
SHE	No	Canada--Crude Monitor	2006	836	11.4	343-527		916	16.4
Draugen	No	Norway--Statoil	2002	826	1.21	420-525		916	2.59
Girassol	No	Angola--Total	2009	877	2.98	400-565		916	3.94
Girassol	No	Angola--Statoil	2009	877	2.98	450-500		916	3.94
Medanito	No	Argentina--Total	2009	860	4.05	375-580		916	5.50
Calypso	No	Trinidad and Tobago	2008	871	5.14	375-565		916	5.68
Hibernia Blend	No	Newfoundland--Statoil	2007	849	3.82	450-500		916	6.23
Azeri-Ceyhan	No	Ceyhan--BP		841	1.35	509-550		917	2.71
Amenam Blend	No	Nigeria--Total	2011	830	0.79	375-550		917	1.65
Azeri Light	No	Azerbaijan--Statoil	2005	851	1.28	500-550		917	2.40
Brass River	No	Africa--Total	2012	824	1.48	375-565		917	3.48
Gimboa	No	Angola--Statoil	2009	902	5.05	370-450		917	4.35
Masila	No	Yemen--Total	2010	854	4.36	375-550		917	5.78
Forties	No	United Kingdom--Total	2011	831	6.54	375-550		917	12.0
Oman	No	Oman--Total	2011	870	13.4	375-550		917	14.4
Tangguh Condensate	No	Indonesia--BP	2010	805	0.32	342-369		917	2.31
Calypso	No	Trinidad and Tobago	2008	871	5.14	400-565		918	5.88
Hungo Blend	No	Angola--Statoil	2008	885	5.66	370-450		918	6.33
Mandji	No	Gabon--Total	2010	876	8.76	375-565		918	9.27
Forties	No	United Kingdom--Total	2011	831	6.54	375-565		918	12.3
Azeri BTC	No	Azerbaijan--Statoil	2012	843	1.18	500-550		919	2.38
Brass River	No	Africa--Total	2012	824	1.48	375-580		919	3.68
Terra Nova	No	Newfoundland--Statoil	2005	859	4.30	450-500		919	6.52
Mandji	No	Gabon--Total	2010	876	8.76	400-565		919	9.37
Oman	No	Oman--Total	2011	870	13.4	375-565		919	14.8
Foinhaven	No	United Kingdom--BP	2010	898	3.50	509-550		919	4.72
Umm Shaif	No	Das Island--BP	2000	839	11.0	369-509		919	18.6
Amenam Blend	No	Nigeria--Total	2011	830	0.79	375-565		920	1.75
Forties	No	United Kingdom--Total	2011	831	6.54	375-580		920	12.6
Poseidon	No	USA--BP	2009	877	14.5	369-509		920	14.9
Al Jurf	No	Libya--Total	2011	873	16.1	375-550		920	21.3
Grane	No	North Sea--Statoil	2012	940	7.67	320-375		920	5.70
Djeno	No	Congo--Total	2010	891	3.74	375-550		921	3.68
Medanito	No	Argentina--Total	2009	860	4.05	400-580		921	5.80
Oman	No	Oman--Total	2011	870	13.4	375-580		921	15.1
Qatar Marine	No	Qatar--Total	2008	862	15.9	375-550		921	19.8
Ekofisk	No	Norway--BP	2011	838	1.59	509-550		921	3.60
Mondo	No	Angola--BP	2008	877	4.12	369-509		922	5.06
Galeota Mix	No	Trinidad and Tobago	2011	812	1.14	509-550		922	6.91
Arabian Light	No	Saudi Arabia--Oil & Gas Journal	1997	855	15.2		650-1050	922	23.1
Ekofisk	No	Norway--Statoil	2011	832	1.83	500-550		922	4.18
Al Jurf	No	Libya--Total	2011	873	16.1	375-565		922	21.3
Al Jurf	No	Libya--Total	2011	873	16.1	400-565		922	21.3
Oseberg Blend	No	Norway--Statoil	2006	836	2.29	420-525		922	4.43
Light Sour Blend	No	Canada--Crude Monitor	2011	835	8.51	343-527		922	13.7
Southern Green Canyon	No	USA Louisiana--BP	2009	886	20.4	369-509		922	20.5
Kuwait	No	Kuwait--Oil & Gas Journal	1997	863	22.0		650-1049	922	30.1
West Texas Sour	No	USA Texas--Oil & Gas Journal	1997	848	13.0		650-1049	922	18.8

Big Hill Sweet	No	USA SPR--DOE	2000	845	4.06		650-1050	923	7.38
Dalia	No	Angola--BP	2007	912	4.53	369-509		923	4.80
Qatar Marine	No	Qatar--Total	2008	862	15.9	375-565		923	20.1
Djeno	No	Congo--Total	2010	891	3.74	375-565		924	3.88
Forties Blend	No	United Kingdom--Statoil	2012	831	6.56	450-500		924	12.8
Eocene	No	Saudi-Kuwait Partitioned Zone--Chevron	2000	942	37.4	340-450	650-850	925	30.8
Basra Light	No	Iraq--BP	2009	875	25.5	369-509		925	30.3
Saxi Batuque Blend	No	Norway--Statoil	2011	855	2.22	450-500		925	3.88
Brass River	No	Africa--Total	2012	824	1.48	400-580		925	3.98
Schiehalion Blend	No	United Kingdom--Statoil	2010	903	4.15	450-500		925	4.74
Forties	No	United Kingdom--Total	2011	831	6.54	400-580		925	13.2
Qatar Marine	No	Qatar--Total	2008	862	15.9	400-565		925	20.5
Umm Shaiff	No	Abu Dhabi--Statoil	2010	840	12.1	375-550		925	20.7
Dalia	No	Angola--BP	2010	914	4.66	369-509		925	4.90
Kissanje	No	Angola--Statoil	2011	871	3.31	450-500		926	4.91
Zakhum Lower	No	Abu Dhabi--Statoil	2010	822	8.55	375-550		926	17.9
Umm Shaiff	No	Abu Dhabi--Statoil	2010	840	12.1	375-565		926	21.1
Hungo	No	Angola--BP	2008	883	5.47	369-509		926	6.72
Bryan Mound Sour	No	USA SPR--DOE	2001	859	11.9		650-1050	926	17.6
West Hackberry Sour	No	USA SPR--DOE	2000	858	12.1		650-1050	926	18.8
Bayou Choctaw Sour	No	USA SPR--DOE	2001	864	11.9		650-1050	927	18.0
Alaskan North Slope	No	USA Alaska--BP	2010	865	8.04	369-509		927	10.9
Skarv	No	Norway--BP	2010	844	2.87	509-550		927	7.15
Oman	No	Oman--Total	2011	870	13.4	400-580		927	15.8
Zakhum Lower	No	Abu Dhabi--Statoil	2010	822	8.55	375-565		927	18.0
Hoops	No	USA--BP	2006	867	10.1	369-509		927	12.7
SHE	No	Canada--Crude Monitor	2011	869	22.4	343-527		928	26.2
Cossack	No	Australia--BP	2000	789	0.36	509-550		928	1.67
Lago Treco	No	Venezuela--Oil & Gas Journal	1997	889	14.1		650-1049	928	16.9
Murban	No	Abu Dhabi--BP	2007	824	6.51	509-550		929	15.6
Arabian Heavy	No	Saudi Arabia--Oil & Gas Journal	1997	883	24.6		650-1050	929	26.8
Plutonio	No	Angola--BP	2010	859	3.18	509-550		929	5.71
Pazflor	No	Angola--BP	2012	900	3.69	369-509		929	4.07
Mondo	No	Angola--Statoil	2008	876	3.68	450-500		930	5.12
Hibernia Blend	No	Newfoundland--Statoil	2007	849	3.82	500-550		930	7.72
Zakhum Lower	No	Abu Dhabi--Statoil	2010	822	8.55	400-565		930	18.4
Eocene	No	Saudi-Kuwait Partitioned Zone--Chevron	2011	940	43.0	340-450	650-850	930	35.4
Girassol	No	Angola--BP	2010	877	3.68	509-550		930	5.71
Volve	No	Norway--Statoil	2008	877	15.1	420-525		931	20.9
Dalia	No	Angola--Total	2009	915	4.66	375-550		931	5.31
Umm Shaiff	No	Abu Dhabi--Statoil	2010	840	12.1	400-565		931	21.7
Dubai	No	Dubai--Total	2001	874	18.6	375-580		931	25.2
Saxi Blend	No	Angola--BP	2010	857	2.23	509-550		931	4.36
Schiehalion Blend	No	United Kingdom--Statoil	2010	903	4.15	500-550		932	5.70
Sirri	No	Iran--Total	2002	858	15.5	375-550		932	23.8
Forozan	No	Iran--Total	2003	877	20.5	375-550		932	25.3
Schiehalion	No	United Kingdom--BP	2010	903	4.15	509-550		932	5.77
Maya	No	Mexico--Oil & Gas Journal	1997	921	32.2		650-1049	932	29.5
Alaskan North Slope	No	USA--Oil & Gas Journal	1997	892	10.4		650-1049	932	11.2
Midale	No	Canada--Crude Monitor	2006	878	20.4	343-527		933	26.0
Forcados	No	Nigeria--Oil & Gas Journal	1997	876	2.45		650-1049	933	3.48

Girassol	No	Angola--Statoil	2009	877	2.98	500-550		933	4.85
Dubai	No	Dubai--Total	2001	874	18.6	375-565		933	25.6
Heidrun	No	North Sea--Statoil	2005	904	4.73	375-420		933	5.32
Dalia	No	Angola--Total	2009	915	4.66	375-565		934	5.42
Dalia	No	Angola--Total	2009	915	4.66	400-565		934	5.42
Big Hill Sour	No	USA SPR--DOE	1998	873	12.3		650-1050	934	17.7
Dubai	No	Dubai--Total	2001	874	18.6	400-565		934	25.7
Gulf of Suez	No	Egypt--BP	2008	869	12.2	509-550		935	18.2
Handil	No	Indonesia--Total	2007	819	0.74	375-550		935	0.97
Bonny Light	No	Nigeria--Total	2011	849	1.27	375-550		935	2.62
Dalia	No	Angola--Statoil	2009	915	4.67	450-500		935	5.52
Terra Nova	No	Newfoundland--Statoil	2005	859	4.30	500-550		935	8.13
Sirri	No	Iran--Total	2002	858	15.5	375-565		935	24.3
Midale	No	Canada--Crude Monitor	2013	878	20.5	343-527		935	27.1
Zakum	No	Abu Dhabi--BP	2000	826	8.42	509-550		935	20.7
Mixed Sour Blend	No	Canada--Crude Monitor	2010	880	15.8	343-527		935	16.0
Isthmus	No	Mexico--Oil & Gas Journal	1997	861	13.6		650-1049	936	21.5
Alba	No	United Kingdom--Statoil	2013	936	11.8	370-450		936	9.64
Dubai	No	Dubai--Total	2001	874	18.6	375-550		936	25.9
Kissanje	No	Angola--BP	2006	873	3.23	509-550		937	5.43
Bonny Light	No	Nigeria--Total	2011	849	1.27	375-565		937	2.62
Bonny Light	No	Nigeria--Total	2011	849	1.27	400-565		937	2.62
Forties Blend	No	United Kingdom--Statoil	2012	831	6.56	500-550		937	15.7
Saturno Blend	No	Angola--BP	2013	900	7.47	369-509		937	8.75
Tia Juana Med	No	Venezuela--Oil & Gas Journal	1997	902	14.1		650-1049	937	15.6
Pazflor	No	Angola--Total	2012	902	3.84	375-550		938	4.50
Forties Blend	No	United Kingdom--BP	2011	831	6.56	509-550		938	15.9
Agbami	No	Nigeria--Statoil	2011	788	0.39	450-500		939	2.07
Pazflor	No	Angola--Total	2012	902	3.84	375-565		939	4.60
Hungo Blend	No	Angola--Statoil	2008	885	5.66	450-500		939	7.98
Clair	No	United Kingdom--BP	2010	912	4.29	369-509		940	5.06
Ea Blend	No	Nigeria--Total	2010	849	0.76	375-550		940	1.69
Pazflor	No	Angola--Total	2012	902	3.84	375-580		940	4.70
Gimboa	No	Angola--Statoil	2009	902	5.05	450-500		940	5.64
Fosterton	No	Canada--Crude Monitor	2012	922	29.7	343-527		940	30.3
Tangguh Condensate	No	Indonesia--BP	2010	805	0.32	509-550		941	2.01
Polvo	No	Brazil--BP	2009	932	10.5	369-509		941	9.38
Bekapai	No	Indonesia--Total	2011	812	0.50	375-550		941	1.41
Saxi Batuque Blend	No	Norway--Statoil	2011	855	2.22	500-550		941	4.70
Draugen	No	Norway--Statoil	2002	826	1.21	525-565		942	4.10
Ea Blend	No	Nigeria--Total	2010	849	0.76	375-565		942	1.70
Forcados	No	Nigeria--Total	2010	873	2.45	375-550		942	3.58
Kissanje	No	Angola--Statoil	2011	871	3.31	500-550		942	5.75
Dalia	No	Angola--BP	2010	914	4.66	509-550		943	6.34
Dalia	No	Angola--BP	2007	912	4.53	509-550		943	6.22
Bekapai	No	Indonesia--Total	2011	812	0.50	375-565		943	1.41
Grane	No	North Sea--Statoil	2012	940	7.67	375-420		943	7.06
Thunder Horse	No	USA--BP	2010	857	6.26	509-550		943	11.2
Bow River South	No	Canada--Crude Monitor	2013	916	26.0	343-527		944	26.6
Bonga	No	Nigeria--Total	2009	875	2.19	375-550		944	3.49
Zafiro Blend	No	Africa--Total	2012	871	2.16	375-550		944	3.59

Forcados	No	Nigeria--Total	2010	873	2.45	375-565		944	3.78
Forcados	No	Nigeria--Total	2010	873	2.45	400-565		944	3.78
Pazflor	No	Angola--Total	2012	902	3.84	400-580		944	4.81
Kuito	No	Angola--Total	2008	922	6.77	375-565		944	7.46
Bekapai	No	Indonesia--Total	2011	812	0.50	375-580		945	1.51
Kuito	No	Angola--Total	2008	922	6.77	375-550		945	7.65
Heidrun	No	North Sea--Statoil	2005	904	4.73	420-525		946	6.43
Zafiro Blend	No	Africa--Total	2012	871	2.16	375-565		946	3.59
Alba	No	United Kingdom--Statoil	2013	936	11.8	450-500		946	11.6
Umm Shaif	No	Das Island--BP	2000	839	11.0	509-550		948	24.2
Zafiro Blend	No	Africa--Total	2012	871	2.16	375-580		948	3.70
Mondo	No	Angola--Statoil	2008	876	3.68	500-550		948	6.16
Lloyd Blend	No	Canada--Crude Monitor	2011	925	32.4	343-527		948	26.2
Bow River North	No	Canada--Crude Monitor	2006	922	26.7	343-527		949	24.2
Pazflor	No	Angola--BP	2012	900	3.69	509-550		949	5.34
Dalia	No	Angola--Statoil	2009	915	4.67	500-550		949	6.36
Kuito	No	Angola--Total	2008	922	6.77	375-580		949	7.78
Southern Green Canyon	No	USA Louisiana--BP	2009	886	20.4	509-550		949	25.8
Hoops	No	USA--BP	2006	867	10.1	509-550		949	17.4
Poseidon	No	USA--BP	2009	877	14.5	509-550		949	20.2
Boscan	No	Venezuela--Oil & Gas Journal	1997	998	55.1		650-1049	950	47.3
Gimboa	No	Angola--Statoil	2009	902	5.05	500-550		951	7.13
Alba	No	United Kingdom--Statoil	2013	936	11.8	500-550		951	13.3
Souedie	No	Syria--Total	2001	909	35.4	375-550		951	40.0
Bekapai	No	Indonesia--Total	2011	812	0.50	400-580		952	1.52
Ea Blend	No	Nigeria--Total	2010	849	0.76	400-565		952	1.81
Mars	No	USA Louisiana--BP	2008	882	18.1	369-509		952	20.6
Bachaquero	No	Venezuela--Oil & Gas Journal	1997	951	22.8		650-1050	953	22.3
Zafiro Blend	No	Africa--Total	2012	871	2.16	400-580		953	3.81
Kuito	No	Angola--Total	2008	922	6.77	400-580		953	7.91
Alaskan North Slope	No	USA Alaska--BP	2010	865	8.04	509-550		954	14.6
Hungo	No	Angola--BP	2008	883	5.47	509-550		955	8.90
Hungo Blend	No	Angola--Statoil	2008	885	5.66	500-550		955	9.26
Smiley-Coleville	No	Canada--Crude Monitor	2013	930	28.7	343-527		956	28.3
Clair	No	United Kingdom--BP	2010	912	4.29	509-550		956	6.16
Mars	No	USA Louisiana--BP	2008	882	18.1	509-550		956	25.3
Lloyd Kerrobert	No	Canada--Crude Monitor	2011	938	30.8	343-527		957	25.8
Grane	No	North Sea--Statoil	2012	940	7.67	420-525		958	8.33
Saturno Blend	No	Angola--BP	2013	900	7.47	509-550		959	11.3
Wabasca Heavy	Unknown	Canada--Crude Monitor	2013	930	37.7	343-527		959	37.8
Eocene	No	Saudi-Kuwait Partitioned Zone--Chevron	2011	940	43.0	450-570	850-1050	960	40.5
Basra Light	No	Iraq--BP	2009	875	25.5	509-550		960	39.6
Wilmingon	No	USA California--Oil & Gas Journal	1997	940	14.3		650-1049	962	15.6
Seria Light	No	Brunei--Total	2010	852	0.77	375-550		962	1.64
Eocene	No	Saudi-Kuwait Partitioned Zone--Chevron	2000	942	37.4	450-570	850-1050	963	39.9
Mondo	No	Angola--BP	2008	877	4.12	509-550		963	6.70
Polvo	No	Brazil--BP	2009	932	10.5	509-550		964	11.9
Seria Light	No	Brunei--Total	2010	852	0.77	375-565		966	1.64
Seria Light	No	Brunei--Total	2010	852	0.77	400-565		966	1.64
Bow River North	No	Canada--Crude Monitor	2013	931	27.6	343-527		966	23.6
Agbami	No	Nigeria--Statoil	2011	788	0.39	500-550		977	2.84

Seal Heavy	Yes-DilBit	Canada--Crude Monitor	2013	924	42.9	343-527		965	43.9
Seal Heavy	Yes-DilBit	Canada--Crude Monitor	2006	934	42.4	343-527		960	40.6
Borealis Heavy Blend	Yes-DilBit	Canada--Crude Monitor	2013	922	35.7	343-527		977	35.5
Statoil Cheecham Blend	Yes-DilBit	Canada--Statoil	2011	925	33.6	343-524	649-975	972	34.5
Statoil Cheecham Blend	Yes-DilBit	Canada--Crude Monitor	2012	925	36.0	343-527		966	33.5
Cold Lake Blend	Yes-DilBit	Canada--ExxonMobil (dnld 2013)	2013	927	34.2		650-1000	963	33.0
Cold Lake	Yes-DilBit	Canada--Crude Monitor	2011	924	34.9	343-527		960	32.6
Access Western Blend	Yes-DilBit	Canada--Crude Monitor	2012	921	34.8	343-527		961	32.6
Kearl	Yes-DilBit	Canada--ExxonMobil		918	31.0		650-1000	972	32.5
Christina Dilbit Blend	Yes-DilBit	Canada--Crude Monitor	2013	920	34.3	343-527		964	32.0
Cold Lake Blend	Yes-DilBit	Canada--ExxonMobil (dnlded 040614)	2014	936	35.7		650-1000	964	31.7
Western Canadian Select	Yes-DilBit	Canada--Crude Monitor	2010	930	32.7	343-527		955	28.3
Western Canadian Select	Yes-DilBit	Canada--Crude Monitor	2013	928	32.3	343-527		955	27.9
Western Canadian Select	Yes-DilBit	Canada--Crude Monitor	2008	926	32.0	343-527		951	26.6
Western Canadian Blend	Yes-DilBit	Canada--Crude Monitor	2006	928	28.1	343-527		942	22.8
Albian Heavy Synthetic	Yes-synthetic	Canada--Crude Monitor	2011	936	23.7	343-527		985	21.3
Albian Heavy Synthetic	Yes-synthetic	Canada--Crude Monitor	2006	939	25.2	343-527		950	16.5
Cerro Negro SCO	Yes-synthetic	Venezuela-Exxon/PdVSA		959	32.0		650-1000	976	33.3
Suncor Synthetic H	Yes-synthetic	Canada--Crude Monitor	2006	935	28.3	343+		976	34.2
Suncor Synthetic H	Yes-synthetic	Canada--Crude Monitor	2013	939	29.9	343-514		973	32.3
Suncor OSA Blend	Yes-synthetic	Canada--Suncor	2002	857	1.63		900-1000	952	5.24
Suncor OSA Blend	Yes-synthetic	Canada--Suncor	2002	857	1.63		800-900	942	4.43
Suncor Synthetic A	Yes-synthetic	Canada--Crude Monitor	2006	861	1.81	343+		933	4.38
Suncor Synthetic A	Yes-synthetic	Canada--Crude Monitor	2011	857	1.54	343+		933	3.82
Suncor OSA Blend	Yes-synthetic	Canada--Suncor	2002	857	1.63		700-800	930	3.35
CNRL (CNS) SCO	Yes-synthetic	Canada--Crude Monitor	2012	849	0.68	343+		931	2.43
Shell Synthetic Light	Yes-synthetic	Canada--Crude Monitor	2010	871	1.22	343+		916	2.29
Long Lake Synthetic	Yes-synthetic	Canada--Crude Monitor	2012	825	0.49	343+		891	1.66
Husky Synthetic Blend	Yes-synthetic	Canada--Crude Monitor	2011	864	0.86	343+		912	1.61
Albian Premium Synthetic	Yes-synthetic	Canada--Crude Monitor	2012	868	0.26	343+		910	0.69
Syncrude Synthetic	Yes-synthetic	Canada--Crude Monitor	2011	861	1.55	343+		933	4.02
Syncrude Synthetic	Yes-synthetic	Canada--Crude Monitor	2011	871	0.87	343+		933	2.05
Surmont Heavy Blend	Yes-synthetic	Canada--Crude Monitor	2012	934	29.4	343-527		955	23.9

Attachment 24

SPECIAL REPORT: Canadian, US processors adding capacity to handle additional oil sands production

07/09/2007

Refiners in the US and operators in Canada are adding capacity to handle additional volumes of bitumen and synthetic crude oils from increased oil sands production. Rising crude prices in the past few years and increased demand for refined products have pushed up oil sands production substantially (see article on p. 43).

Producers also have to decide what types of products will match up with future processing configurations in Canada and the US. They have the choice of producing bitumen, synthetic crude oil (SCO), a synthetic-bitumen blend (synbit), or a condensate-bitumen blend (dilbit).

According to a 2006 study from Canada's National Energy Board, the light-heavy crude price differential will remain wide for the next several years until sufficient upgrading capacity is added.[1] Because international heavy crude output is also rising, NEB predicts that Canadian crude will continue to be heavily discounted.

Core markets for oil sands crudes include Canada, US Petroleum Administration for Defense District (PADD) II, PADD IV, and Washington state.[1] Canadian producers are also considering expansion into markets in the US Mideast, US Gulf Coast, and even perhaps Asia.

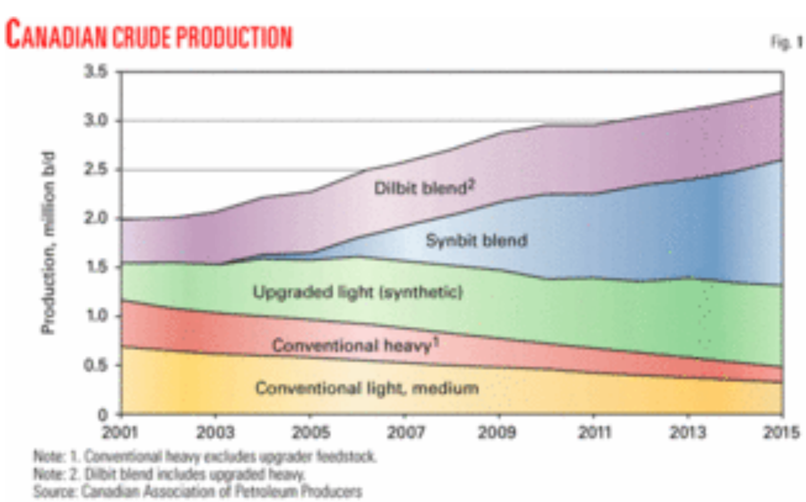

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Fig. 1 shows that production in Canadian crude will increase to 3.3 million b/d in 2015 from about 2.5 million b/d in

2006.[2]

Bitumen vs. SCO

New Canadian oil sands production must either upgrade bitumen to SCO, or dilute it to synbit or dilbit, before transporting it to the end user. Incentives for producers to invest in processing include the ability to capture the light-heavy differential. SCO is more marketable and easier to transport than bitumen blends.

Bitumen requires diluent blending for pipeline transport, has a high residual content that requires more conversion (coking or hydrocracking), and is of low quality.[2] Bitumen is not a good fit with refineries designed for light, sweet crudes. It also requires large amounts of hydrogen for hydroprocessing and creates many unwanted by-products.

SCO, on the other hand, can have a much higher quality, depending on the degree of processing. Premium SCO is a bottomless, refined product. Sour synthetic is partially upgraded and may or may not have a bottoms component. And other new formulations are planned in new projects.[2]

Disadvantages of SCO in conventional refineries are the low quality of distillate produced, high amounts of aromatics, and that only a limited amount of SCO can be processed.

Light sweet SCO in particular has a low sulfur content and produces very little heavy fuel oil.[3] The latter is desirable in Alberta, where there is almost no market for heavy fuel oil.

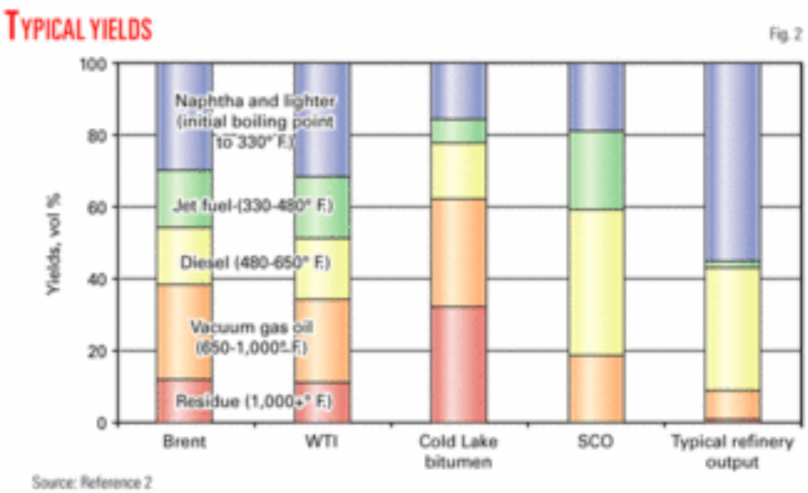

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Fig. 2 shows refinery yields that are feeding different crudes. It shows that SCO is a much higher quality crude than bitumen.

In Alberta, much of the bitumen is upgraded to SCO. Three major upgraders produced about 258,000 b/d (Suncor Energy Inc.), 261,000 b/d (Syncrude), and 141,000 b/d (Shell Canada) of SCO in 2005.[3]

Suncor's plant produces light sweet crude, medium sour crude, and diesel. The Syncrude plant produces light sweet SCO. The Shell upgrader produces intermediate refinery feedstocks and sweet and heavy SCOs.

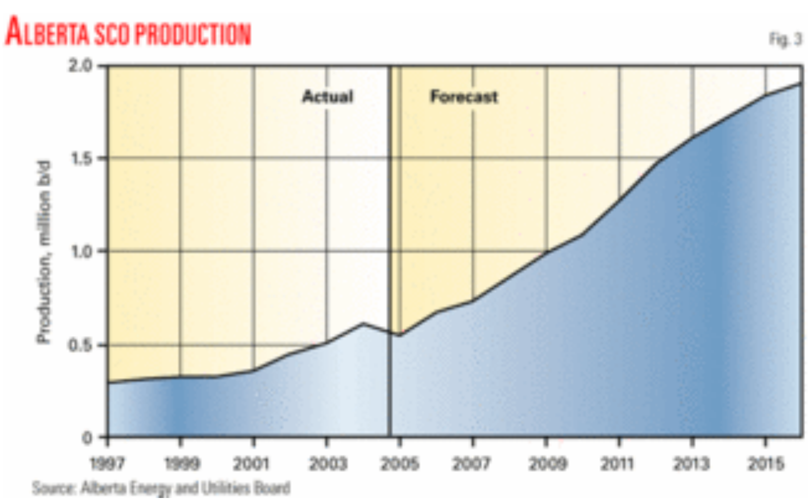

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Fig. 3 shows expected SCO production from Alberta based on project expansions and new upgraders.[3]

Demand for Alberta SCO will be from existing markets that are losing other sources of light crudes. The largest export markets for Alberta SCO and bitumen are the US Midwest and Rocky Mountain regions.

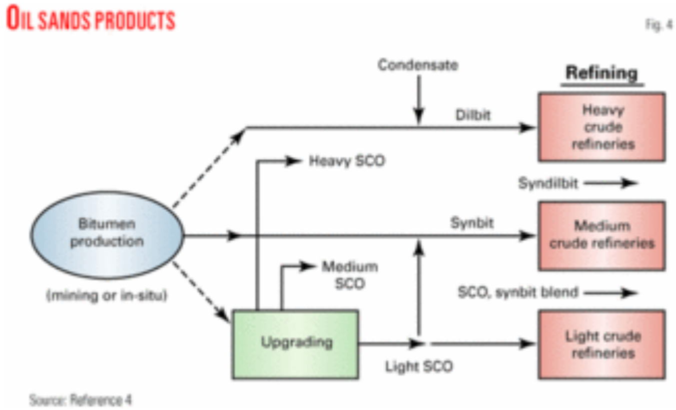

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Fig. 4 shows that oil sands products have become more diverse and are targeting different refining markets.[4]

Canadian refining, upgrading

According to the NEB study, Canada's refining and upgrading industry does not hold significant growth opportunities for oil sands producers. Canada's 19 refineries have a combined crude processing capacity of just more than 2 million b/d.

In 2005, less than 50% of Ontario's crude requirements were from western Canada; only 22% was SCO and blended bitumen.[1] There are few growth opportunities for western Canadian crude in Ontario and Quebec.

Western Canadian refineries process exclusively western Canadian production. In 2005, nearly 40% of crude refined in western Canada was SCO (35%) and blended bitumen (4%).[1 3] According to the Alberta Energy and Utilities Board, the nine refineries in western Canada had a total crude capacity of about 577,000 b/d.

In 2006, the five refineries in Alberta fed about 206,000 b/d of SCO and about 20,000 b/d of non-upgraded bitumen.[3] The five refineries have a combined crude capacity of about 476,400 b/d.

In 2003, Petro-Canada announced that it would convert its Edmonton refinery to handle exclusively oil sands crude, according to the NEB study. By 2008, the refinery will process 135,000 b/d of oil sands crude, which will displace conventional crude currently processed. The NEB study reported that Petro-Canada would obtain these supplies through an agreement with Suncor, which will process bitumen from Petro-Canada's MacKay River in situ facility into sour SCO.

In March 2006, Husky Energy Inc. announced that it is proceeding with detailed engineering for its project that would nearly double capacity at its upgrader at Lloydminster to 150,000 b/d by 2009 from its current 80,000 b/d. "It would enable Husky to capture full value from increased production at its Cold Lake and Athabasca oil sands projects," according to the NEB study.

Husky also announced on May 7 that it is acquiring Valero Energy Corp.'s 165,000-b/sd Lima, Ohio, refinery. The $1.9 billion sale was to close at the end of second-quarter 2007. This would allow Husky a direct outlet for its oil sands production.

There have been three merchant upgrader proposals announced, according to the NEB study.

The BA Heartland Upgrader project will take place in three phases, with the first phase starting up in early 2008. The first phase will process 77,000 b/d of bitumen blend. The project will have a total processing capacity of 250,000 b/d.

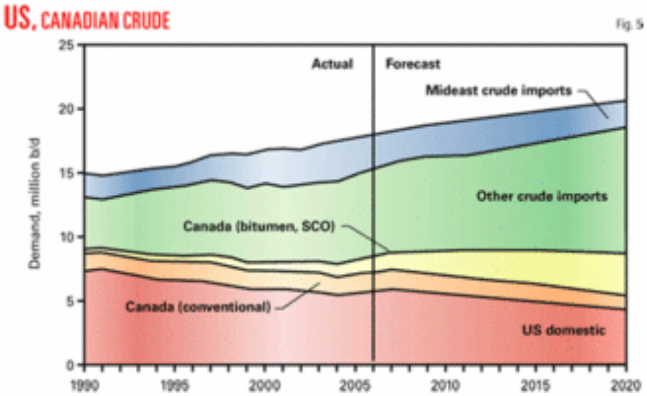
North West Upgrading Inc. is planning to construct a heavy oil upgrader near Edmonton. The first phase is to come on stream in early 2010 and will upgrade 50,000 b/d of bitumen to SCO, according to NEB. North West is planning as many as three additional phases by 2015, with a total processing capacity of 231,000 b/d and would produce 180,000 b/d of SCO and 42,000 b/d of diluent.

Peace River Oil Upgrading Inc. has proposed a 20,000-b/d bitumen processing facility near McLennan, Alta., according to NEB.

US refining

US refineries are Canada's largest market for crude exports and, according to the NEB study, "possess the greatest potential for increased penetration of oil sands derived crude oil." In 2005, Canada supplied nearly 10% of US crude feed.

Fig. 5 shows combined US and Canada crude production and that falling production in the US will be offset by more crude from Canada.



Click here to enlarge image

In US Petroleum Administration for Defense District I (East Coast), only the United Refining Co. refinery, Warren, Pa., processes western Canadian crude. In 2005, it processed 21% SCO and 8% blended bitumen, according to the NEB study. In September 2006, the company announced that it was delaying a project for a new coker due to "uncertainty in the petroleum markets."

PADD II (US Midwest) is the largest market for western Canadian crude: In 2005, 70% of western Canada's crude exports were to PADD II, according to NEB. SCO comprised 20% of that volume and blended bitumen was 19%.

Because refineries in Northern PADD II are complex, they are well positioned to run more bitumen blends and SCO. Especially wide light-heavy differentials are resulting from rising output from oil sands and conventional production in Northern states.

"This could be alleviated in the future," according to NEB, "as a number of companies identified an interest in constructing a coker or developing refinery expansion plans that would allow them to process heavier crude oil to take advantage of the light-heavy differential and the expected increase in oil sands production."

Canadian heavy crude has the largest market share in US Midwest refineries, which processed 3.3 million b/d of crude in 2005, of which 24% was heavy sour crude.[4] Nearly all was from Canada. Canadian light crude had a smaller market share.

PADD III (US Gulf Coast) is an attractive market for Canadian producers due to the complexity of refineries there. Bitumen blends especially could compete against imports from Venezuela and Mexico.

PADD IV (US Rocky Mountain) refineries have traditionally been a significant market for western Canadian crudes. Recently, however, higher prices have resulted in more drilling and production in the district, according to NEB.

"Refiners in PADD IV are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crudes," according to the NEB study.

"The large discount is in reaction to aggressive Canadian crude pricing, shortage of refinery capacity, and the lack of pipeline capacity to move the crude oil to other markets. Due to its size and the complexity of its refineries, PADD IV will continue to be a marginal growth market for western Canadian crude oil, particularly SCO and blended bitumen," says the study.

It considers PADD V (US West Coast) a growth market for western Canadian crude, especially Washington. This is due to a decline in the availability of Alaska North Slope crude. In 2006, Washington received only 11% of its crude from Canada.

Click here to enlarge image

Fig. 6 shows the different markets and pipeline systems for western Canadian crude.

Market expansion

High oil prices will continue to compel oil sands expansions. The NEB study outlined a scenario in which oil sands crude would expand its markets:

1. Fill existing markets, including Washington, PADD II, PADD IV, and additional volumes in Canada.
2. Expand into southern PADD II and PADD III and refinery expansions and conversions in northern PADD II, IV, and V. Southern PADD II could take 40,000 b/d more with the expansion of the Spearhead pipeline, and the US Gulf Coast could take up to 400,000 b/d if the necessary pipeline capacity existed. NEB estimates that in the next 10 years, PADD II could take an additional 500,000 b/d.
3. Develop new markets such as California and Asia. This would require new pipelines or expansions.

Because the light-heavy differentials should continue for the near future, this price environment should provide a strong incentive for US refiners to add conversion capacity. Traditional inland markets could add up to 200,000 b/d of resid conversion capacity by 2010.[4]

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Attachment 25

SPE -120174-PP

The Future of California's Oil Supply

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This paper was prepared for presentation at the 2009 SPE Western Regional Meeting held in San Jose, California, USA, 24–26 March 2009.

Abstract

Once an oil exporter, California now depends on imports for more than 60% of its oil supply. This paper examines the oil production outlook for each of California's major oil sources, including California itself. Oil production trends, published geological and engineering reports, and proposed developments in California's supply area are reviewed to define supply trends, especially for the medium-to-heavy, sour crudes that are processed in California's refineries. Refinery upgrading capacity is already highly developed in California, thus it is assumed that a competitive advantage in heavy, sour crudes will continue, although refining heavy oil releases more carbon dioxide.

About a quarter of California's imports are from Alaska, the rest from foreign sources including Saudi Arabia, Ecuador and Iraq. Before foreign sources became so important, California's refining industry processed California's own crudes and Alaska's North Slope crude. Like those crudes, oil from northern Saudi Arabia, southeast Iraq, and Ecuador is also sour and medium to heavy, ranging from 16 to 35° API and from 2 to more than 3% sulfur by weight. By far the most important sour crude development in California's supply area is Saudi Arabia's 900,000 BOPD Manifa project, originally slated for completion in 2011 but now facing delays. Manifa contains oil that ranges from 26 to 31° API and from 2.8 to 3.7% sulfur. Over the longer term, Alaska will continue to play an important supply role if the Chuckchi and Beaufort Seas live up to expectations.

Middle East production is not increasing, yet oil cargoes from the Middle East have to pass growing Asian markets to reach California. Alaska and Mexico also supply oil to the Pacific Basin, but are facing production declines. The effect of rising Asian demand on Pacific Basin oil markets is already visible, with significant amounts of oil coming to California from Atlantic Basin sources such as Angola, Brazil, and Argentina.

The US West Coast pipeline system is separate from the integrated East Coast, Gulf Coast and Midwest system, so energy security issues for the West Coast may differ from those of the country as a whole. There are policy options that could affect California's oil supply security, including increased oil development in Alaska or offshore California, development of additional oil pipeline outlets on Canada's Pacific Coast or substituting natural gas for oil if possible. All of these policy options are currently the subject of political debate.

Historical Oil Production Trends in California's Supply Area

Historical oil production trends are of interest because, unlike reserve estimates, they are readily verifiable factual information. Another issue with published reserve data is the quality of the supporting information; Alberta produces a detailed annual reserves report, while Saudi Arabia and Iraq publish only national aggregate figures. All of the oil production volumes reported in this section are from the Oil and Gas Journal or the Alaska Division of Oil and Gas and do not include natural gas plant liquids.

Iraq's oil production peaked in 1979 at 3.43 million BOPD. In 2007 it was 2.09 million BOPD, but production levels had been affected by internal instability and were higher in 2008.

Saudi Arabia's oil production peaked in 1981 at 9.64 million BOPD. The Saudis have consistently claimed a productive capacity substantially greater than this, but have not produced as much since, even in times of high oil prices. In 2007 Saudi oil production was 8.63 million BOPD.

California's own oil production peaked in 1985 at 1.1 million BOPD. By 2006 it had declined to 685,000 BOPD. California's heavy oil fields have been intensively developed and production from them is expected to decline further.

Alaska's oil production peaked in 1988 at 2.14 million BOPD; in 2007 it was 756,000 BOPD. Alaska's oil production is dominated by the Prudhoe Bay Field, which is at an advanced stage of decline, but substantial exploration potential remains, both onshore and offshore.

Oil production in Mexico peaked in 2004 at 3.38 million BOPD; in 2007 it produced 3.08 million BOPD. Mexico's oil production is expected to continue to decline because of the increasing maturity of the offshore oil fields in the Gulf of Campeche.

Ecuador's oil production was 535,000 BOPD in 2006, but in 2007 it was only 499,000 BOPD. One year of declining production may be a result of many factors, and is not necessarily indicative of near-term supply problems.

The oil production levels of Angola, Brazil, and Canada are currently at all-time highs due to increased heavy oil development in Canada, and to deep offshore discoveries in Brazil and Angola. These 'ABC' countries are likely to play an increasing role in California's oil supply.

California's Oil Production

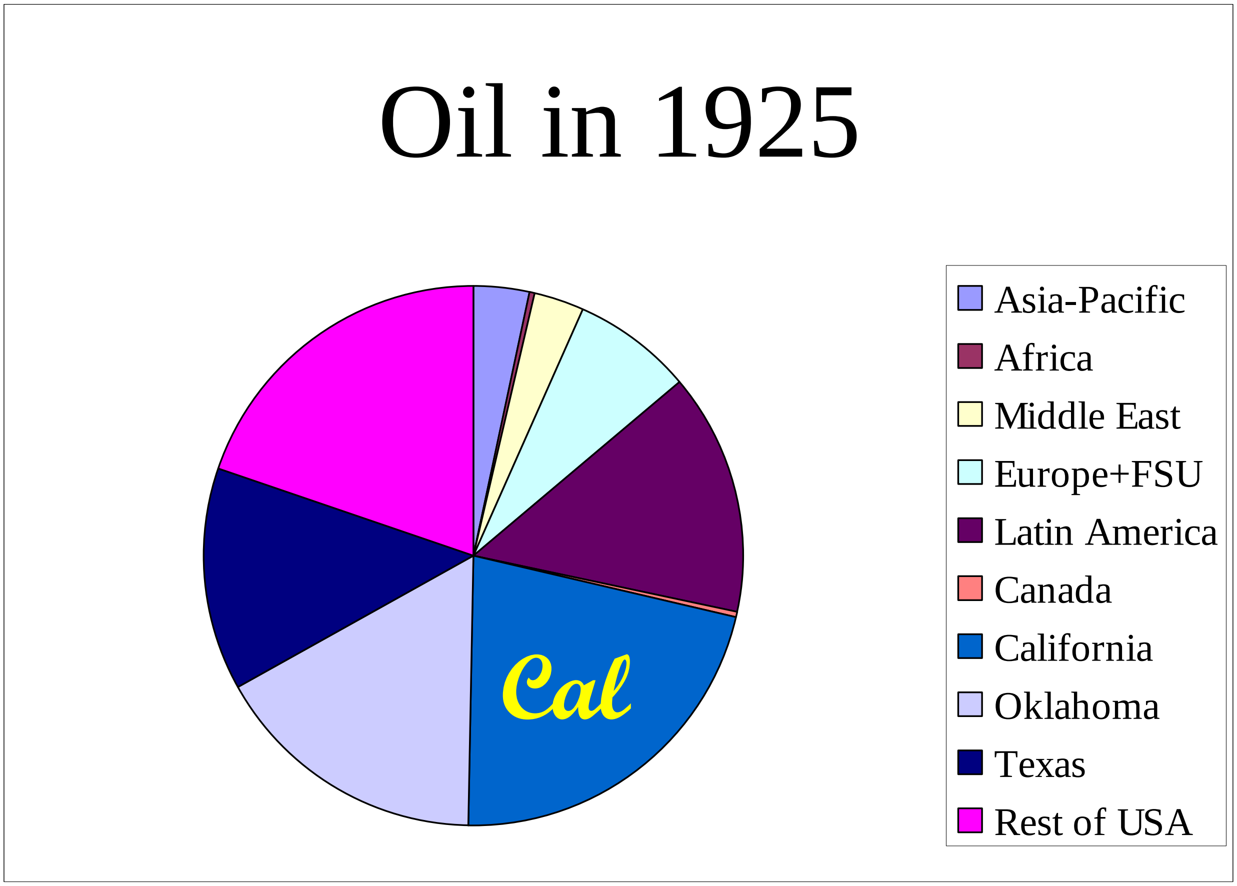
Although California's oil production did not peak until 1985, its importance in the world of oil was greatest around 1925, when California accounted for more than 22% of world oil production (American Petroleum Institute, 1993) This was the peak of development of the Los Angeles Basin oil fields, but before the discovery of the East Texas Field or the development of the Permian Basin. Figure 1 shows the relative importance of different oil-producing regions in 1925.

Because of California's history as an oil producing and exporting province, its refining industry was originally built to process local crudes. Table 1 shows the API gravity and sulfur content of two of the most important California crude streams.

Table 1: California Oil Properties (Guerard, 1984)

Field	Kern River	Wilmington
API Gravity	12.6°	19.4°
Sulfur Content	1.19%	1.59%
Viscosity@100°F	6,000 cp	470 cp

Figure 1: World Oil Production in 1925



Total: 2,926,000 BOPD

California's produced 683,000 BOPD in 2006. Of this production, 409,000 BOPD was heavy oil, and 113,000 BOPD of the total was produced offshore (California Division of Oil, Gas, & Geothermal Resources, 2006).

California's Heavy Oil Production is dominated by four large, steam-enhanced oil production projects in Kern County. These are the Midway-Sunset, Kern River and Cymric Fields, and the Tulare Sand in South Belridge Field. These four projects accounted for about 69% of California's heavy oil production in 2006. All of these are declining except for Cymric, which has had its life extended by the development of a deeper reservoir, the Etchegoin. The recent production history of these four projects is shown in Figure 2. Note that the values shown in the figure for South Belridge are for the Tulare sand only and do not include the light oil production from the Belridge Diatomite. Although the production of large amounts of incremental heavy oil from these reservoirs is a great technical accomplishment, that same success now makes further production declines inevitable because about half of the OOIP has already been produced.

Other known heavy oil and tar sand deposits in California have not been developed because the oil is too viscous. The largest of these, the Foxen Tar Sand in the Santa Maria Basin, is estimated to have 2 billion barrels of OOIP while other known tar sands at Oxnard, Arroyo Grande and Paris Valley have less than 1 billion barrels of OOIP in aggregate (Hallmark, 1982). This compares to estimated OOIP of 6.2 billion barrels for the Midway-Sunset Field and 4.1 billion barrels for the Kern River Field (Roadifer, 1986). The conclusion is that these undeveloped oil accumulations are smaller than existing major projects and are not likely to arrest onshore production declines. The greatest potential for increasing California's oil production probably lies offshore.

Figure 2 (California Division of Oil, Gas, & Geothermal Resources, 1994 through 2006)

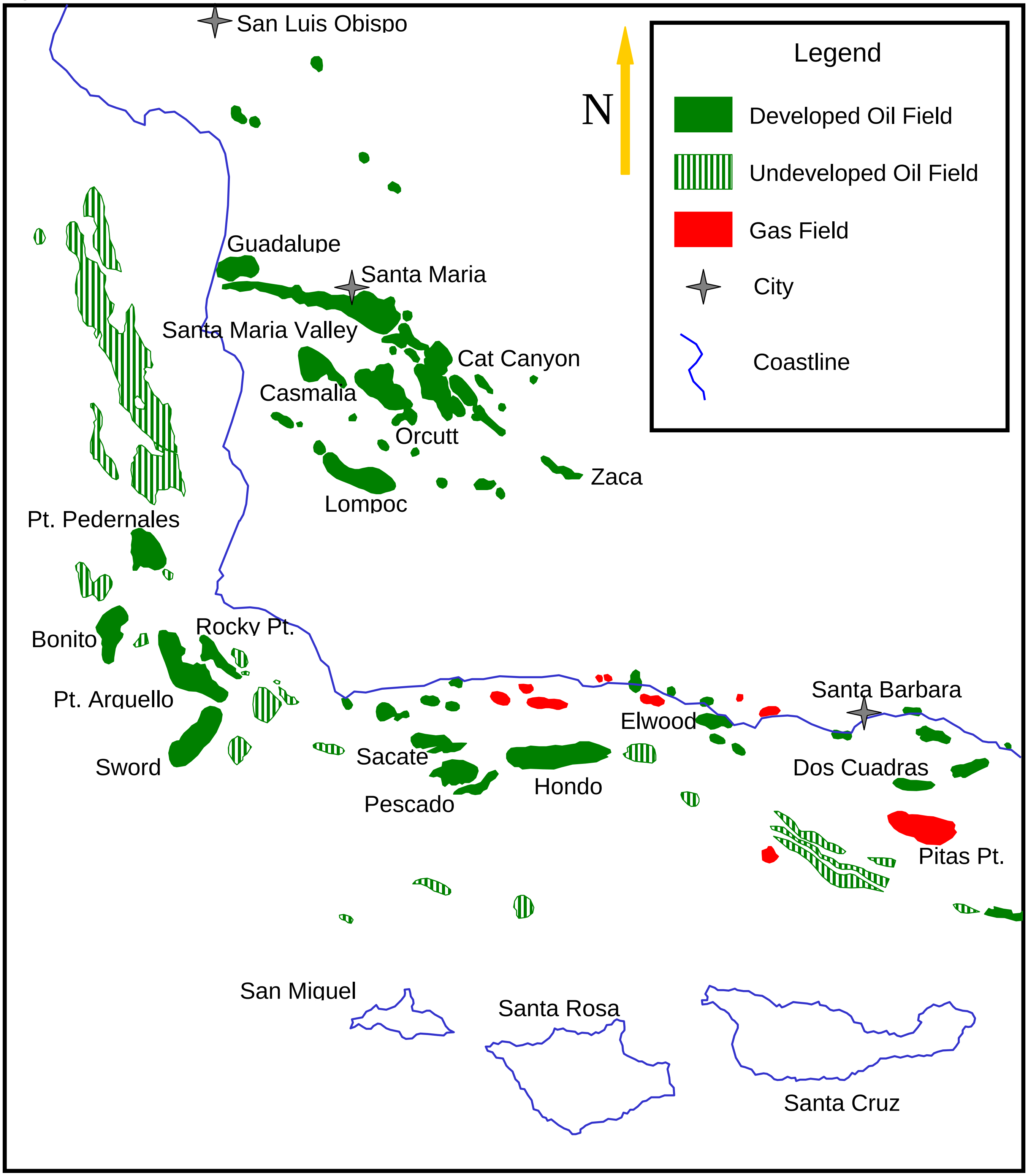
Offshore California

One of the few areas in the world that has large, undeveloped oil reserves is offshore California.
Offshore oil production from wooden piers began at Summerland around 1890. There were concerns about the impact of offshore drilling even early in its history, so a compromise was reached in which all of the state offshore royalties were dedicated for many years to the Department of Beaches and Parks.

A major oil spill in 1969 strengthened opposition to offshore drilling and today there is in practice a ban on new platform installations. This has not prevented all new field developments; Bonito and Sword are recent extended-reach developments from existing platforms. Large heavy oil fields north of Point Sal are far from existing infrastructure and remain undeveloped. Figure 3 shows developed and undeveloped oil fields around Santa Barbara County. The offshore field outlines in the figure are from MMS and the onshore field outlines are from the California Division of Oil and Gas. Although only a small part of the California Coastline is shown in the figure, it includes most of the known offshore oil reserves of the state. These were estimated at 303 million barrels of remaining proved reserves, 1.166 billion barrels of remaining unproved reserves, and 149 million barrels of known resources on expired leases at yearend 2003 (Syms. and Voskanian, 2007).

In addition to these known fields, there is considerable exploration potential offshore California. That potential is greatest offshore Southern California, but is also significant offshore Central and Northern California. At a $46 per barrel price assumption, the undiscovered economically recoverable oil resources offshore Southern, Central and Northern California are estimated at 3.9, 1.9 and 1.5 billion barrels respectively (MMS, 2006). This 7.3 billion barrel total rises to 8.6 billion barrels in the $80 per barrel case. Resources of this magnitude could represent a significant addition to California's oil supply.

Figure 3: Oil Fields of the Santa Barabara Channel and Santa Maria Basin, California



Alaska

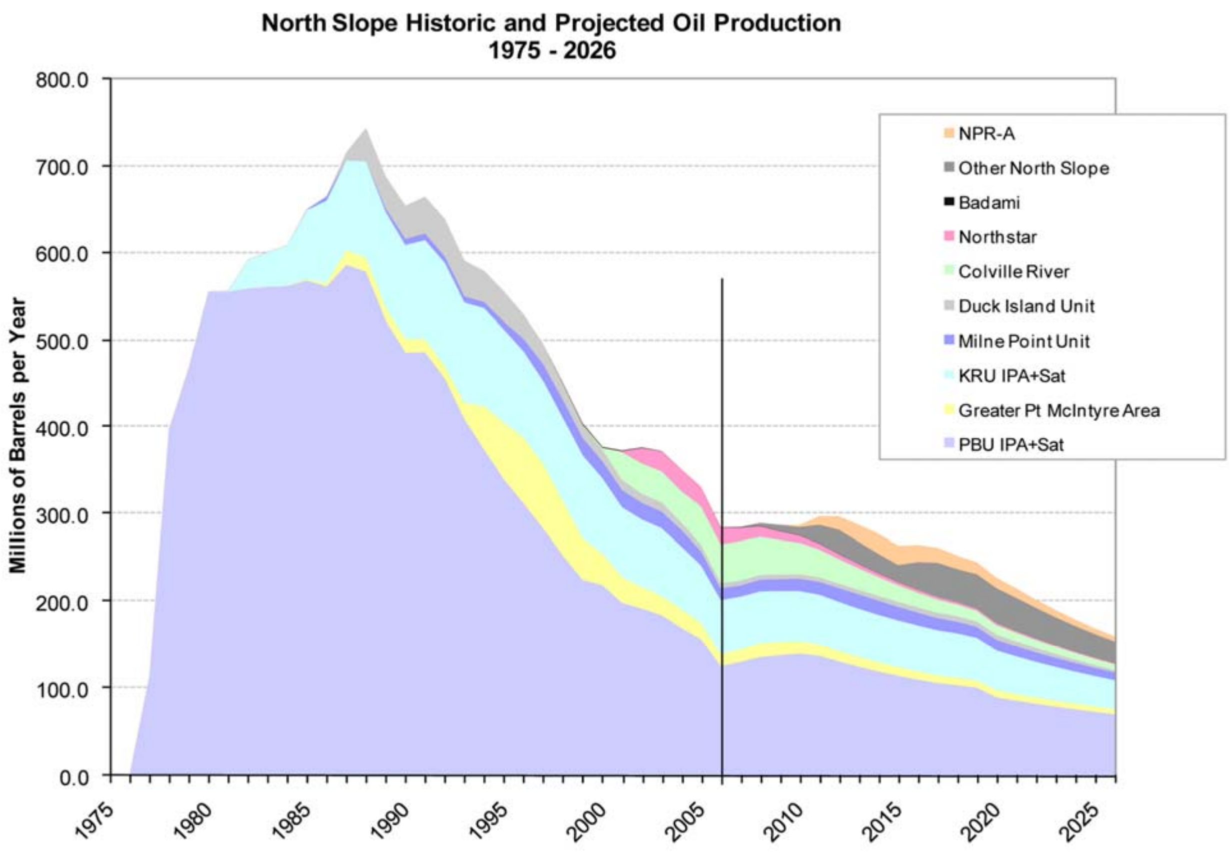
Alaska's oil production is currently about a third of its 1988 peak. Alaska is a very high cost area, so low oil prices discouraged development from 1986 until about 2005. In addition, the Trans-Alaska Pipeline partners benefit from the substantial tariff, which gives them a competitive advantage. Figure 4 shows the history and projections for North Slope oil production. This figure is based on remaining reserves in existing fields. The important observation is that existing and proposed Alaskan developments are not likely to provide a major increase in

Alaskan oil supply; major new developments would be needed.

Much of the discussion of oil development on Alaska's North Slope centers on the coastal plain of the Arctic National Wildlife Refuge. The area in question is only a very small part of the North Slope, and an important structure within it was tested by an exploratory well in 1986 – 1987. The well was drilled on a native inholding in the 1002 area. The results of this well and several others were not used by the USGS in its assessment of ANWR potential for confidentiality reasons.

The Chukchi and Beaufort Seas have large oil potential, as evidenced by the number of tracts receiving bids in recent federal lease sales. Chukchi Sea lease sale 193 in 2008 received $2.66 billion in winning bids on 488 blocks (MMS, 2008). In the Beaufort Sea, 2007 lease sale 202 received $42 million in winning bids on 92 blocks (MMS, 2007) and 2005 lease sale 195 received $47 million in winning bids on 121 blocks (MMS, 2005). These tracts could contain sufficient resources to offset the projected declines shown in Figure 4. The undiscovered economically recoverable oil resources in federal waters offshore Alaska are estimated at 8.35 billion barrels at a $46 per barrel price assumption, and 21.5 billion barrels in the $80 per barrel case (MMS, 2006). Note that the offshore Alaska resource estimates are more sensitive to oil prices than those offshore California.

Figure 4 (Alaska Division of Oil and Gas, 2008)



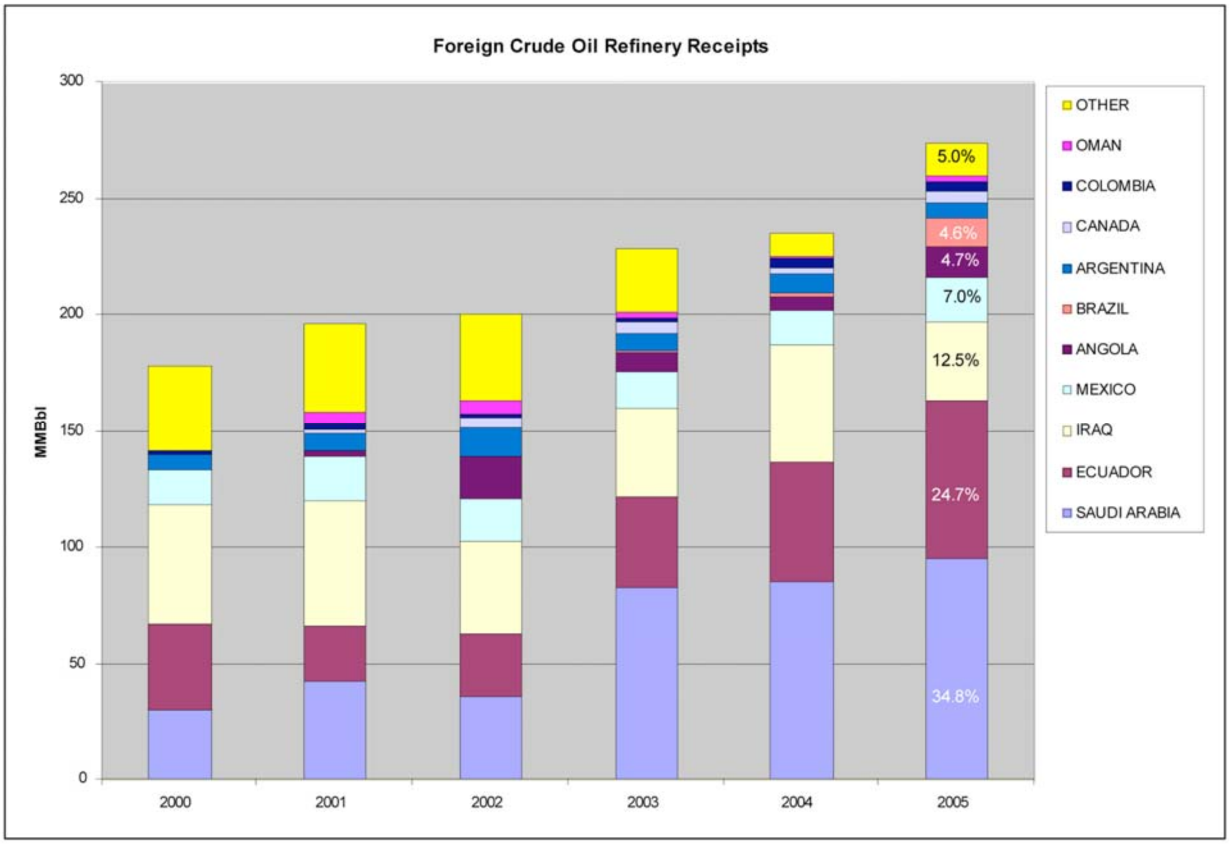
Source: Alaska Division of Oil and Gas (2008)

Foreign Sources of Oil to California

Figure 5 shows the countries of origin for California's foreign crude receipts from 2000 through 2005[7]. Note the dominance of Saudi Arabia, Ecuador and Iraq, with Mexico coming in a distant fourth in oil supply to California. Another important development is the appearance of Angola, Brazil and Canada as significant suppliers in 2005.

California's oil sources are the main suppliers of heavy, sour crudes to the Pacific Basin. For this reason, California competes directly with other Pacific Rim consumers that have the ability to process these heavier oils.

Figure 5 (California Energy Commission, 2007)



Saudi Arabia and Iraq

Most Saudi production comes from older onshore fields, but the Arab Medium and Heavy grades used by California refineries are primarily produced offshore northernmost Saudi Arabia. The oil fields of southeast Iraq, Kuwait and northernmost Saudi Arabia produce primarily from sandstone reservoirs of Cretaceous age. These fields are characterized by multiple pay zones and strong natural water drives. Cretaceous carbonate reservoirs and shallow heavy oil are also present.

Table 2: Safaniya Field Reservoir Parameters[1]

Reservoir	Safaniya	Khafji
Net Thickness (ft)	136	137
Oil Gravity	27	27
Viscosity (cp)	6.4	4.55
Sulfur Content	2.93 %	2.84 %
Porosity	26 %	25 %
Permeability (md)	5700	6250

[1]Saudi Aramco, *Oil Reservoirs, Table of Basic Data,* Year-End 1980

The Safaniya Field was discovered in 1951 and is the world's largest offshore oil field. Production of Arab Heavy crude comes from two major sands, the Safaniya and the Khafji. Peak historical production was about 1.8 million BOPD in 1981. Table 2 above shows that these reservoirs combine excellent permeability with low oil viscosity at reservoir conditions so this is a conventional production operation even though we call the oil Arab Heavy.

The Zuluf Field was discovered in 1965. Production of Arab Medium crude comes from the Khafji sand. Production capacity was increased to 1.1 million BOPD in 1993.

The northern Saudi oil fields are becoming mature, but Qatif and Abu Safah of the southern Saudi fields were expanded in 2004 and produce Arab Medium. There is also a proposed 900,000 BOPD heavy oil development of the Manifa Field, but it has recently been delayed from its completion date of yearend 2011 (Saudi Aramco cancels Manifa Contract, 2008). Manifa lies between the northern and southern producing areas and produces Arab Heavy from carbonate reservoirs of Cretaceous age. Table 3 gives parameters of the three most important reservoirs in Manifa Field.

The southern Saudi fields produce mostly Arab Light from carbonate reservoirs of Jurassic age. These reservoirs do not have natural water drives and are waterflooded for that reason. Horizontal drilling is now used extensively in Saudi oil projects.

Table 3: Manifa Field Reservoir Parameters[2]

Reservoir	U. Ratawi	L. Ratawi	Manifa
Net Thickness (ft)	50	188	71
Oil Gravity	31	26	29
Viscosity (cp)	2.6	4.4	2.8
Sulfur Content	2.77 %	3.66 %	2.97 %
Porosity	17 %	22 %	20 %
Permeability (md)	50	600	300

About 80% of Iraq's oil production comes from the southeast. Northern Iraq's oil production is exported to the Mediterranean via Turkey and does not supply California. Further Iraq development depends on political stability and investment levels, which are difficult to predict at this time. Project Kuwait, which is a redevelopment of the fields in northern Kuwait, has been repeatedly delayed. For these reasons, future production levels are difficult to predict.

Latin America and West Africa

Ecuador was the source of a quarter of California's foreign imports in 2005. Nearly all of Ecuador's oil production comes from the Oriente Basin, which is located east of the Andes. Unlike the Middle East, where production is dominated by a small number of very large fields, oil production in Ecuador comes from numerous fields. Although Ecuador's production was less in 2007 than in 2006, several additional heavy oil fields could be developed including Pungarayacu, which is estimated to contain between 4.5 and 7 billion barrels of oil in place (Ecuador's Giant Pungarayacu to See Heavy Oil Appraisal, 2008).

Mexico has been a significant supplier to California in the past, but is facing major production declines (Watkins, 2008). Mexico's oil production has been dominated by the Cantarrell Complex that came onstream in 1980, and further production gains were achieved with nitrogen injection, but now the field is in decline.

Brazil supplies some oil to California and production is increasing due to deep-water developments. Perhaps the most exciting current development in oil supply anywhere is the series of recent discoveries in the presalt

[2] Saudi Aramco, *Oil Reservoirs, Table of Basic Data,* Year-End 1980

sediments of the Santos Basin. If recent government estimates of 50 to 80 billion barrels of oil prove accurate, this will have a major effect on the world oil trade and is likely to greatly increase the volume of oil shipped from the Atlantic to the Pacific Basin.

Argentina, Venezuela and Angola also supply some oil to California. It is not anticipated that Agentina's oil exports will grow significantly in the near future. Venezuela has huge heavy oil reserves. It is not currently a major supplier of oil to California, but eventual development of these resources could change that. Angola is now a supplier to California, its oil production is increasing and it has joined OPEC.

Canada as a Supplier to California

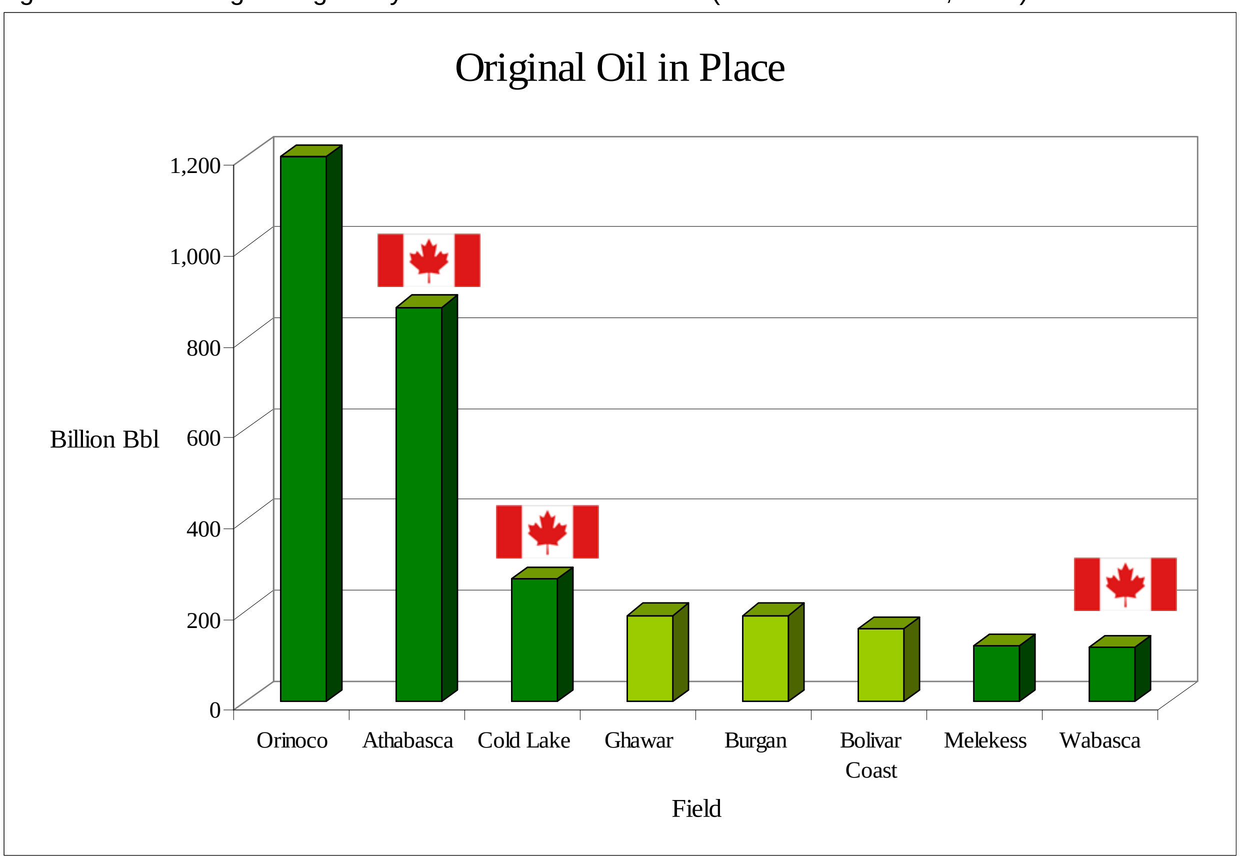
The heavy oil resources of Venezuela and Canada are the World's largest hydrocarbon accumulations. Figure 6 shows the world's eight largest hydrocarbon accumulations by oil in place. The source for this information dates to 1987, but such tabulations are difficult to find.

The economics of oil sands production recently became highly favorable and development is proceeding much more rapidly in Canada than in Venezuela. Canada has become the largest supplier of oil to the US and Canadian heavy oil dominates Midwest supply now. The Canadian Association of Petroleum Producers claims that production from the oil sands in Alberta will be 3.3 to 4.0 million BOPD in 2020.

Pipelines from the oil sands to Kitimat or Prince Rupert on the Pacific Coast have been proposed, and could supply California. There is an existing pipeline to Burnaby in British Columbia that has recently been expanded to 200,000 BOPD.

Oil sands production is more carbon-intensive than conventional oil. This carbon comes primarily from two processes; steam generation for bitumen extraction and production of hydrogen for refinery upgrading processes.

Figure 6: World's Eight Largest Hydrocarbon Accumulations (Data from Roadifer, 1986)

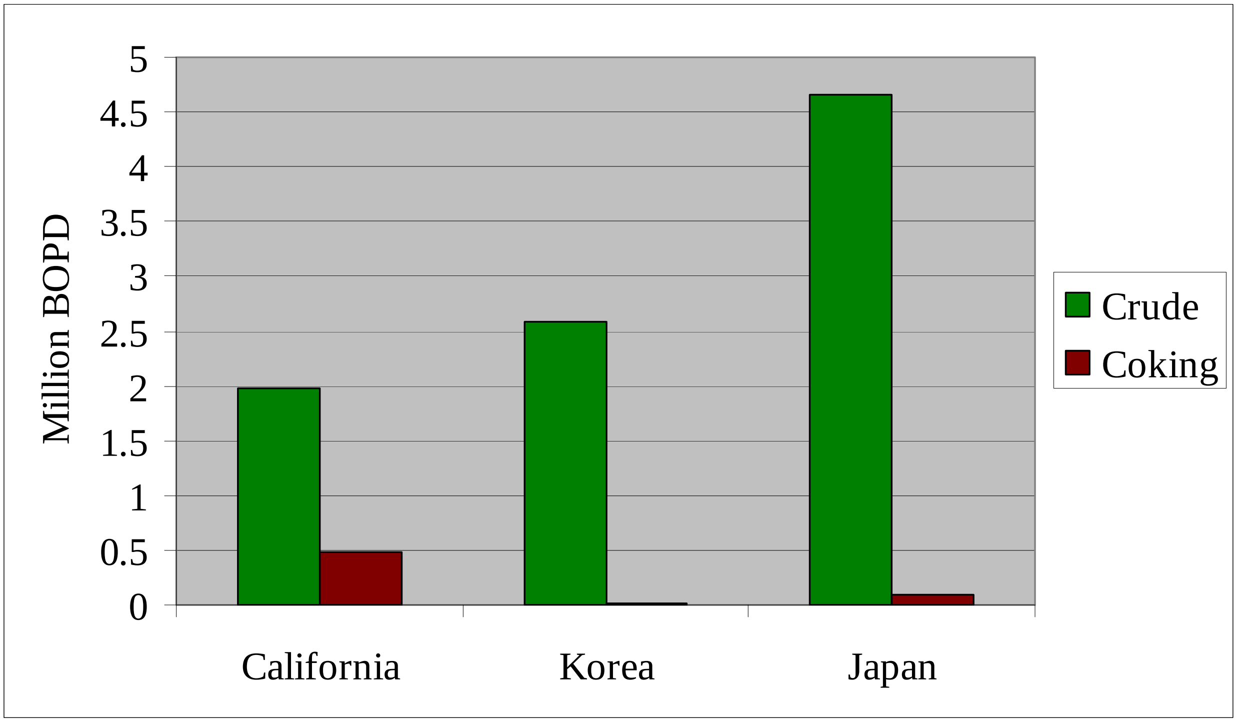


California's Refining Capacity

California refineries have evolved from processing California oil to processing a mix of California crudes, Alaska North Slope, Arab Heavy, and Ecuador Oriente, among others. Because of this history, California refineries are designed to process heavy oil.

Refineries designed to process heavy crude typically have three stages; distillation, cracking and coking. The ratio of coking capacity to crude distillation capacity gives an approximation of the extent to which a region's refineries have been designed to process heavy crude. Figure 7 shows that coking capacity in California is 25% of primary crude distillation capacity, as compared to 2.0% in Japan and 0.7% in Korea. This illustrates that enormous investments have already been made in heavy oil refining capacity in California.

Figure 7: Crude Distillation versus Coking Capacity for Major Pacific Oil Markets (Data from Nakamura, 2007)



Energy Security Considerations and the Low Carbon Fuel Standard

Concerns about energy security in California mostly revolve around oil. Because the waterborne crude market is global, regional oil price differentials are a function of freight rates if the market is in equilibrium. The problem is that oil supply disruptions are not equilibrium situations almost by definition. During disruptions energy security is an issue. The time required for markets to reach equilibrium is the time required to rearrange marine supply chains, which is to say that long supply lines decrease security. Diversification of oil supply sources increases security because it is unlikely that that multiple sources would be disrupted at the same time. Substitution increases energy security as long as the supply of the substitute is independent of the supply of oil.

Concerns about climate change have led California to propose a low-carbon fuel standard. The goal is to reduce carbon equivalent emissions per unit of fuel energy by 10 percent by 2020 (Farrell and Sperling, 2007). The problem with this approach is that it does not address the actual problem, which is total emissions, while working against California's competitive strength in the refining of heavy oil.

Fuel Substitution Possibilities

Oil is used primarily for transportation fuel in California. Alternative vehicle fuels include natural gas, propane, biofuels and electricity.

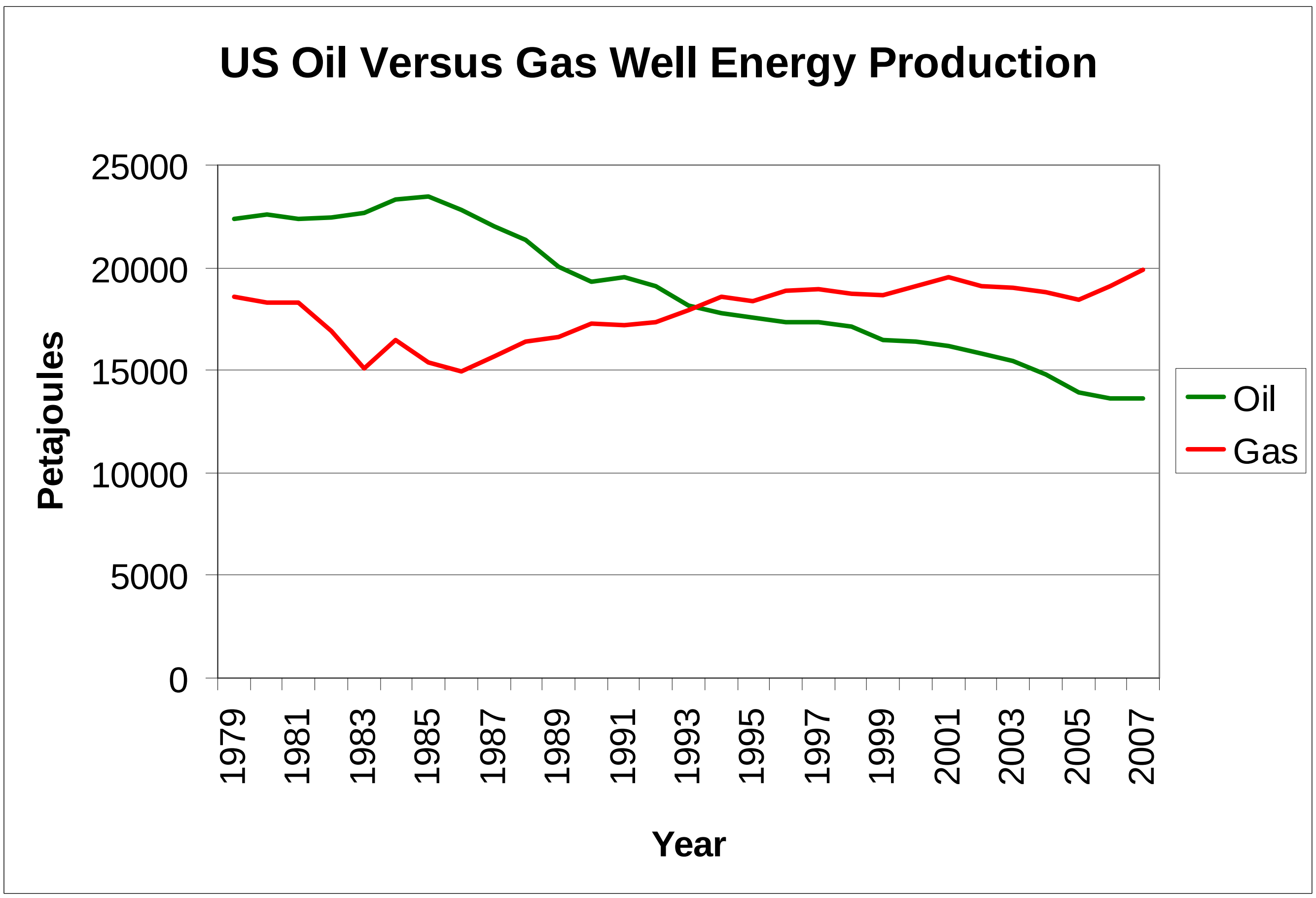
Natural gas is the least environmentally damaging transportation fuel, but storage is more difficult than for liquid hydrocarbon fuels. California's natural gas currently comes from the U.S. and Canada. Natural gas has several desireable aspects; it is cheaper than oil, large new resources have been found in the U.S. lower-48, and Alaska also has very large volumes of undeveloped natural gas. Natural gas vehicles also do not have the toxic aromatic compounds that are a problem with gasoline and Diesel fumes.

Since 1977, the Energy Information Administration has published figures for associated and non-associated gas production. Figure 8 is an approximate comparison between the energy yielded from oil wells and that from gas wells over time in the United States. Oil production was converted at 5.95 GJ per barrel, marketed dry gas at 1025 btu per cubic foot and gas liquids at 4.525 GJ per barrel, which is the value for propane. In order to adjust for the fact that a significant proportion of gas comes from oil wells, the energy curves labeled Oil and Gas in Figure 9 were calculated by the following approach:

$$Oil = energy(oil) + energy(assocgas) + energy(NGL) \times \left(\frac{volume(assocgas)}{volume(gas)} \right)$$

$$Gas = energy(nonassocgas) + energy(NGL) \times \left(\frac{volume(nonassocgas)}{volume(gas)} \right)$$

Figure 8: US Oil and Gas in Energy Units (Data source DOE/EIA)



Propane, biofuels and electric cars raise more difficult questions. Propane supplies are limited and it is an essential feedstock for the petrochemical industry. With biofuels, once again supplies are limited and biofuels compete with the food supply for land and fertilizer. Electricity comes from a variety of sources in California and it can be considered secure because nearly all of these sources are domestic. Electric cars are politically popular, but have an energy storage problem which limits their range. This is the reason that an earlier attempt to mandate electric cars in California was not successful. For the purposes of this paper, electric cars will not be considered current technology.

Of the currently available alternatives, natural gas appears to have the greatest potential for replacing a portion of California's oil usage in the transportation sector. Thailand, a nation which faces a similar choice between locallyproduced gas and Pacific Basin oil markets, has embarked on a program to increase the number of natural gas vehicles on its roads from 122,375 in 2008 to 332,000 in 2012. Their goal is to replace 20% of oil imports by then (Petroleum Authority of Thailand, 2008).

Conclusions

1. California is increasingly dependent on the Middle East and Ecuador. This means the state is affected by factors outside of local control, such as the Manifa Field delay in Saudi Arabia. An additional concern about these areas is that reserves are reported without supporting information, leaving future supplies uncertain.
2. California's refining industry is built for heavy, sour crudes. This capability represents an enormous cumulative investment in a technology that gives us an energy security advantage.
3. Canada is the most promising oil source for California in the long term. It has very large reserves of the heavy oils that California's refining industry is built for. Canada's reporting of reserves is highly transparent, removing uncertainty over the magnitude of its resources.
4. Environmental concerns restrict oil development offshore California. Another environmental regulation, the low-carbon fuel standard, reduces California's energy security by discouraging oil from Canada and onshore California.
5. Substitution of compressed natural gas for liquid fuels in a portion of the vehicle fleet improves security.

Acknowledgments

Greg Croft was supported by a Jane Lewis Fellowship art the University of California at Berkeley.

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