APPENDIX F

McGOVERN REPORT

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SJMcGovern Report for South Coast Air Quality Management District
Tesoro Los Angeles Refinery Integration and Compliance Project

By: Dr. Stephen J McGovern, PE

Date: October 12, 2015

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Contents

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I have been retained by the South Coast Air Quality Management District (SCAQMD) in connection with the SCAQMD's review of the Tesoro Los Angeles Refinery Integration and Compliance Project (the LARIC project) under the California Environmental Quality Act.

I have worked in and around the petroleum refining and/or renewable fuels industries for over 40 years. I have a Doctorate in Chemical Engineering from Princeton University and am a licensed Professional Engineer in New Jersey. I have recently served on two different National Research Council Committees regarding conventional and alternative fuels. I teach industry recognized courses on various aspects of refining technology. My Curriculum Vitae is attached as Appendix A.

The SCAQMD is preparing an Environmental Impact Report (EIR) for the proposed Tesoro Los Angeles Refinery Integration and Compliance (LARIC) Project at the Tesoro Los Angeles Refinery pursuant to the California Environmental Quality Act (CEQA) and has asked me to consider the following specific questions posed by SCAQMD as well as other issues as they may arise:

1. Does the proposed LARIC Project provide the ability to change the slate of crude oil that could be delivered and processed at the Tesoro Los Angeles Refinery?

2. If so, how would those qualities change and what effect could they have in the blending and crude processes (even if the permits for those processes are not changing)? Would the crudes be significantly heavier (have lower American Petroleum Institute (API) gravities) and/or contain more sulfur and be more acidic than the crudes they would replace? Would the crudes delivered to the Tesoro Los Angeles Refinery be significantly lighter and/or contain more volatile organic hydrocarbons than the crudes they would replace?

3. If the Tesoro Los Angeles Refinery modifications would facilitate refining a different slate of crude oil, would that change in slate cause an increase in criteria air pollutants, toxic air contaminants or GHG emissions from the Tesoro Los Angeles Refinery during the refining process?

4. If the Tesoro Los Angeles Refinery modifications would facilitate refining a different slate of crude oil, would that change in slate cause an increase in the risk of upset (increase in the potential for accidents that could lead to emergency events)?

Before answering these questions, we must define how the term “slate” as applied to crude oil input to a refinery is used in the petroleum industry. As used in this context “slate” can refer to a list of potential crude oils that the refiner can choose to purchase and be delivered as input to the refinery or it can refer to the blend of crude oils actually purchased and processed in a refinery. This report will address both definitions.

In short, my conclusions are summarized in the following numbered paragraphs. For detailed information that provides the basis for the following conclusions, the reader is referred to sections I, II, III, and IV.

1. The LARIC project will not change the modes by which Tesoro receives crude oil into the refinery complex. As such, the LARIC project will not allow Tesoro to access crudes that are not currently available to the refinery. The LARIC project will make minor changes to crude oil refining capabilities of the Tesoro Los Angeles Refinery, but will not increase the refinery's ability to process higher sulfur crudes or significantly change the refinery's ability to process lighter or heavier crudes. Therefore, the average quality of the crudes processed by the refinery will not change significantly as a result of the LARIC project. The quality of the crudes that Tesoro currently processes varies widely, from very heavy sour crudes to very light sweet crudes. Tesoro will continue to decide which crudes to purchase in the future at any given time based on a variety of factors, such as the quality and price of crudes on the market, the market demand for different products such as gasoline, jet fuel, or diesel fuel, the market prices for different products, and the refinery's configuration. It is difficult to predict with certainty what crudes Tesoro will purchase at any given time in the future because of changes in the world market forces. However, certain limitations applicable to the crudes currently received and processed will continue to apply in the future, as summarized in the following item and explained in more detail later in this report. Therefore, the LARIC project will not change the slate of crude oil that could be delivered to and processed at the Los Angeles refinery.

2. Certain aspects of the Tesoro Los Angeles Refinery's processing configuration limit the instantaneous quality of the crude mix that can be processed. These aspects of the refinery processing configuration will not be changed significantly by this project. Tesoro will continue to purchase crudes of varying quality to match the refinery's existing limitations in API gravity and sulfur content before processing them. Tesoro will continue to purchase crudes within the current range after implementation of the LARIC project, regardless of any change in the sources of crudes. Therefore, the air pollutant emissions from process equipment attributable to varying crude types will remain substantially the same.

3. Although some of the units in the Tesoro Los Angeles Refinery are being modified and new units are being added, the slate of crude oils available to the refinery will not change and the minor changes in average crude oil quality that might result would not cause an increase in operating emissions of criteria air pollutants, toxic air contaminants or GHG emissions after the mitigation methods that are part of the LARIC are applied.

4. The changes being made as a result of this project will not allow the refinery to

process a different slate of crude oil. As such, there will be no crude oil changes that make the refinery more prone to upset or potential leaks of hazardous or toxic substances. Although the LARIC project will not change the slate of crude oil processed in the refinery, some of the other changes proposed in this project will most likely reduce the probability of the release of toxic or hazardous substance within SCAQMD.

Information included in this document was provided both by Tesoro and through publically available sources. However, detailed information concerning the quality and potential sources of crude oil both processed in the past and contemplated to be processed in the future at Tesoro's Los Angeles Refinery are business confidential information and therefore are not included in the EIR or this report. Furthermore, detailed information describing the Tesoro Los Angeles Refinery's processing capabilities, other than information included in operating permits and other public documents is also confidential and not included in this report.

I. To What Extent Will the LARIC Project Change the Quality of Crudes Delivered to the Refinery?

A. How Do Refiners Decide Which Crudes to Purchase?

Crude oil is a complex mixture of thousands of individual chemical compounds (molecules). An oil refinery separates and transforms these complex mixtures into the different, saleable, specification products that consumers demand such as gasoline, jet fuel, diesel fuel, asphalt and lubricating oils. Refineries also produce byproducts such as liquefied petroleum gas (LPG), petroleum coke, and sulfur.

The "oil industry" consists of producers of crude oil, refiners of crude oil and distributors, transporters and marketers of crude oil and finished products. Very few US oil companies perform all of these tasks. For example, Tesoro is an independent oil refiner, but does not drill for or produce crude oil. It purchases its crude oil through both short and long term contracts and on the spot market. As such, Tesoro must rely on other entities (oil producing companies and countries) to ensure that the quality of the crude oil it purchases meets specifications. Crude oils are produced and sold by various entities including governmental organizations such as member nations of the Organization of Petroleum Exporting Countries (OPEC), private companies under license to various governments and private companies producing oil from privately owned land.

Crude oils are generally categorized based on weight or "gravity" and sulfur content. Gravity (API gravity) is an indirect measure of the amount of gasoline and distillate (diesel fuel, jet fuel and home heating oil are collectively referred to as distillates) boiling range material that exist in the crude as it is delivered to the refinery. Lower gravity crudes contain less gasoline and distillate and larger amounts of heavy tar-like components that require more complex refineries to convert these heavy molecules into gasoline and distillate. Current governmental regulations require gasoline and diesel fuel to be essentially sulfur free, so processing higher sulfur crudes also requires more complex refineries and additional costs to remove the sulfur from the final product. Since it requires less refinery equipment and operating expenses to convert light sweet crudes into gasoline and distillates than it does to convert heavy sour crudes, light sweet crudes are generally more valuable (higher priced) than heavy sour crudes. Crude traders generally price crude oils based on their relative weight and sulfur content. The Energy Information Administration of the US Department of Energy publishes monthly average costs of imported crude oils as a function of API gravity. Lower gravity crudes generally cost less for refineries to purchase than higher gravity crudes, but require more complex and expensive refineries to convert them into saleable products.

Gasoline typically has an API gravity of about 50, while diesel has an API gravity of about 35. Vacuum gas oil (VGO) and residue (the other major components of crude oil) have gravities of about 22 and 10 respectively. The gasoline that is naturally found in crude oil has a low octane and must be “reformed” in a naphtha catalytic reformer unit to increase its octane. The vacuum gas oil is “cracked” in a Fluid Catalytic Cracking (FCC) unit or hydrocracking unit to convert most of it to gasoline and diesel fuel. The residue is either sold as asphalt or heavy fuel oil or is cracked in a coker to produce additional gasoline and diesel fuel and pet coke. Lower gravity crudes with more VGO and residue require more processing in more complex and expensive refineries.

When a refinery is first built, the types and sizes of the various process units are chosen to match the characteristics of the specific “design” crude oil based on a detailed crude assay of the design oil or mix of oils. As new crude sources become available and sources of the design crude decline, refiners must purchase different crudes and blend them together to match refinery processing capabilities as closely as possible. Refiners also add new processing units or modify existing units to either handle the new crude oil mix, produce a different product mix or meet new product or emission specifications. Refiners evaluate these required configurational changes and crude oil purchases with computer programs know as LPs. (Linear Programing Optimization Routines).

Linear Programing is a complex mathematical tool that can be purchased from several different companies. Many refiners use the PIMS model offered by AspenTech. These models have mathematical representations of each refinery process unit and track essentially every major input, intermediate stream and product stream within the refinery. The basic model is licensed from AspenTech, but the refiner must then modify it to include all of the capabilities and constraints of the specific refinery being modeled. The constraints include operational, economic, logistical and environmental factors. The unit-specific information only changes when hardware or environmental requirements change. Product demand and pricing, as well as crude oil price and availability can change every day.

The refinery and the corporate planning groups run these LP models every day. The models are used to determine the optimal crude mix the refinery should purchase from the crudes that are available to it. Once the crudes arrive at the refinery (this could be several weeks or months after the purchase decision is made), the model is run again to determine the most profitable product mix that can be made from the crudes “on-hand”, given “today’s” prices and product demands. The models are also used as longer term planning tools to determine if an investment such as the LARIC project will be beneficial to the refinery.

There are many different crude oils available on the world market. The “slate” of crude oils available to any refinery is a subset of the world market that is defined by transportation and delivery modes available to the refinery. In addition to gravity and sulfur, samples of each crude are analyzed in more detail by both producers and refiners. These detailed analyses are called crude assays. A crude assay on a single sample of crude oil can cost anywhere from $5,000 to more than $100,000. The cost of the crude assay increases with the level of detail desired. Refiners use these more detailed crude assays to determine the blends of various crudes that can be economically processed in their refinery.

LP models use available crude assay information to represent the crude oil input into the refinery. The refiners must either develop the crude assay information themselves or purchase the information from other sources. Some limited crude assay information is available from open sources, but the detailed information that is required to run a refinery LP is often copyrighted and cannot be distributed to the public without compensating the copyright owner. Detailed crude assays developed by refiners for use in their own LP modeling have competitive value and are therefore considered trade secret and business confidential information.

Although each crude oil has a specific name and generally accepted quality, every cargo is a blend of various oils produced from a number of individual wells, each well producing a slightly different quality oil. Therefore, a single crude assay is only an approximation of the actual quality of crude oil delivered to a refinery. For example, Crude Oil Quality, Inc. maintains a website (www.crudemonitor.ca) that publishes limited analytical data on shipments of a number of Canadian crude oils. Figures 1 and 2 show the variability in Gravity, Sulfur, Total Acid Number (TAN) and Benzene of Western Canadian Select and Christina Dilbit. These are two, high volume, heavy, sour Canadian export crudes. The LARIC project will not change the availability of these crudes to the Tesoro Los Angeles refinery. This information is only included in this report to show typical crude oil quality variability. For example, the API gravity of Western Canadian Select has varied almost annually between about 19.5 and 21.5 API. Higher gravity occurs in the winter when more diluent is required to reduce viscosity.

Figure 1: Selected Properties of Western Canadian Select

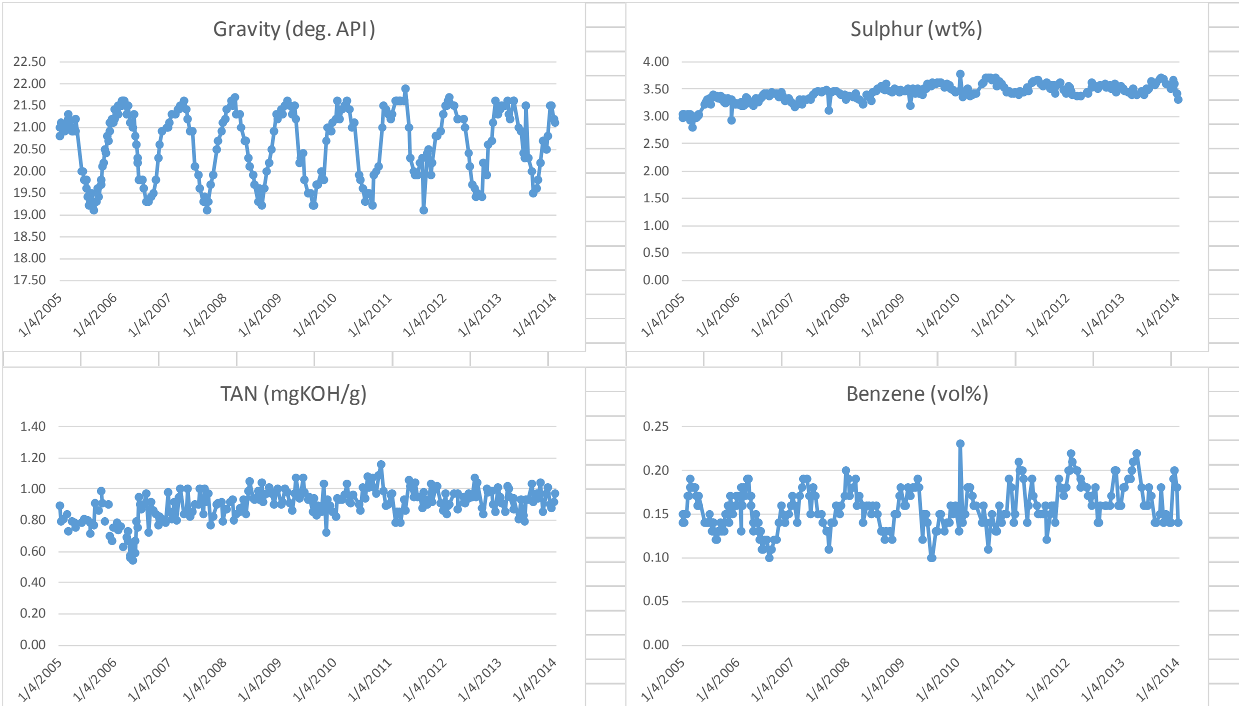
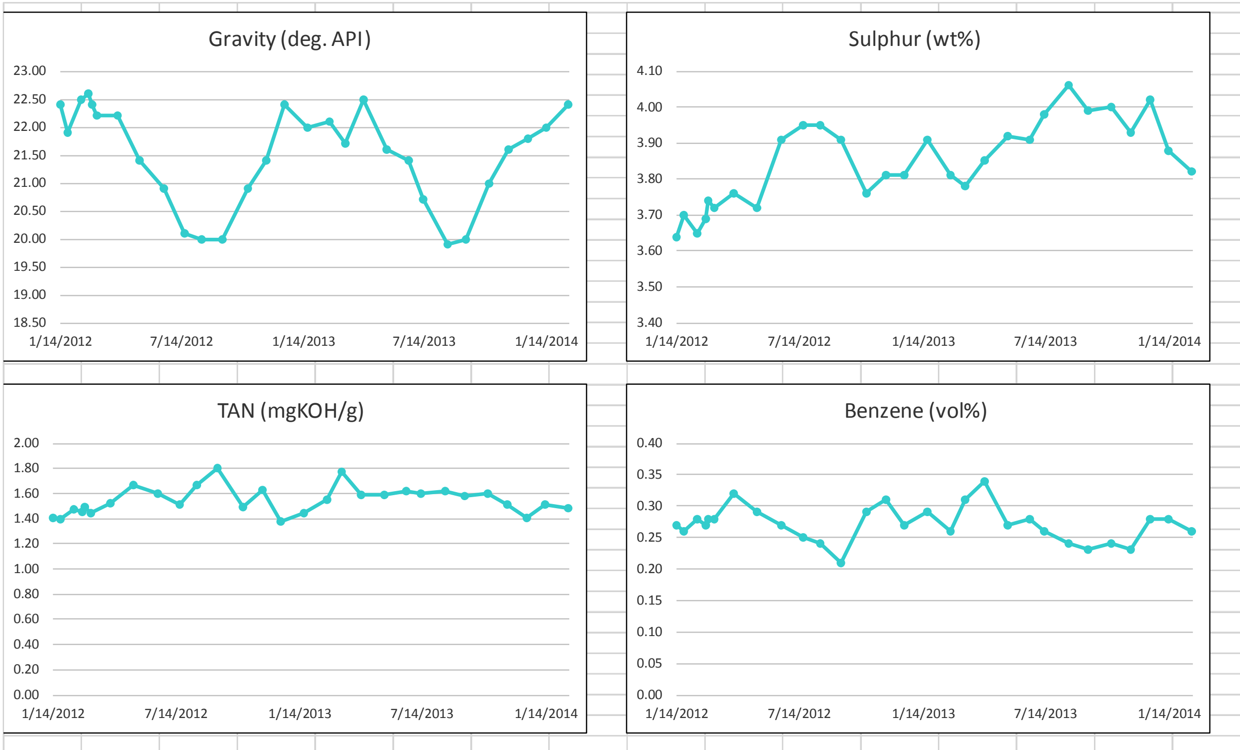


Figure 2: Selected Properties of Christina Dilbit



LP modeling, which includes refinery configuration and economic considerations (crude price, relative product prices and operating costs), determines the actual crude mix and crude rates that the refinery will run to maximize profits. Each refinery has a different configuration and therefore is limited in the types of crude that can be economically processed in that particular refinery.[1] The major processing units typically found in most refineries include: crude unit, vacuum tower, naphtha pretreater and reformer, jet fuel treating, distillate desulfurization units, fluid catalytic cracking unit, alkylation unit and a gas recovery/treating facility. Some refineries might also have a hydrocracker, a heavy gas oil (FCC feed) hydrotreater, a coker, a catalytic polymerization unit, a propane treating unit, a hydrogen plant, lube oil and/or asphalt production facilities as well as other specialty units such as an isomerization unit or benzene conversion unit.[2] Each of these units operates on a different fraction of the crude oil. The exact refinery configuration and the processing capabilities of the individual units determine the crude oils that the refinery is capable of processing. For example, the lifting capabilities of

[1] Both the US Department of Energy (DOE) and the Oil and Gas Journal publish annual listings of the processing capacities of every US refinery and the major processing units within each refinery. The DOE listing is available for download from the EIA website, free of charge. The Oil and Gas Journal survey is available for a nominal fee.

[2] Refineries also have support facilities to generate steam and electricity, to produce boiler feed water, to recover and produce elemental sulfur. A refinery also includes units whose specific function is to minimize the release of potential contaminants into the environment. A schematic of a typical complex oil refinery can be found in AP-42 Figure 5.1.1 on the EPA website and is reproduced herein as Figure 3. A schematic of the existing Carson and Wilmington Operations of the Tesoro Refinery is shown in Figure 2-8 of the EIR for the proposed Project.

the crude unit and the size of the naphtha reformer limit the average naphtha content of the crude oil that the refinery can process. Most of the sulfur that enters a refinery with the crude oil is removed by the various processing units and converted to elemental sulfur by the sulfur plant. The size of the sulfur plant relative to the crude processing capacity of the refinery determines the maximum **average** crude sulfur content that the refinery can process. The size of the FCC unit, hydrocrackers and coker determine the amounts of VGO and residue that the refinery can process and therefore the heaviness of the crude that can be processed.

Based on the size of the various processing units in the Tesoro Los Angeles Refinery as reported in the U.S. DOE Energy Information Administration website, the maximum average crude oil sulfur content that the Tesoro Los Angeles Refinery complex can remove from its products at full capacity is about 1.5 wt%. Some sulfur also leaves the refinery with the various products, so the actual **average** crude sulfur content that can be processed is slightly higher than this value and is about 1.9 wt%. This is an average value. Individual crudes with sulfur contents above 3% can be processed in the refinery. Also, running the refinery at lower than maximum capacity allows a higher average sulfur crude slate to be processed.

The LARIC project will not increase the sulfur plant capacity nor the ability of the refinery to run a higher average crude sulfur content. A new jet fuel treating unit is being added to improve jet fuel quality but not increase jet fuel production or sulfur content. The coke drums are not being modified as part of this project, so the coke production capacity and hence the amount of sulfur that leaves the refinery with the coke is not expected to change significantly. Thus, the Tesoro Los Angeles refinery complex will not be able to process a significantly higher sulfur content crude slate following the LARIC project.

A refinery does not always run crude oils with sulfur contents that “fill” its sulfur removal/recovery capabilities. Crude oil sulfur content is one of many factors that impact the price and “processibility” of a crude oil. The yield structure and properties of the various fractions of the crude also impact its relative value to any given refinery. Thus, the sulfur content of the crude being run in the refinery on any given day is usually less than the maximum refinery capabilities. The scheduled or unscheduled shutdown of various refinery units can also change the maximum sulfur content of the crudes that can be processed on any given day.

The capacities of the Cokers, hydrocrackers and FCC units (the units that upgrade the heaviest portions of the crude) will be modified as a result of the LARIC project. The Wilmington FCC will be shut down. The Wilmington coker heater permit will be modified to allow an approximately 20% higher maximum heater firing rate. The Wilmington coker only processes a small fraction of the total input of the refinery and only processes heavy crudes. Since the coke drums are not increasing in capacity, this increase in furnace duty associated with the coker heater permit change is expected to provide at most a 2% (6,000 barrels per day) increase in crude oil throughput capacity mostly in the distillate and VGO range boiling range.

The coker fractionator processes some of the Wilmington crude in addition to the coker products. The "worst case scenario" from an overall emissions perspective is to utilize this additional capability to process additional crude. This is the case that was evaluated in the EIR, so the emission increases associated with an increase in coker furnace permit will be relatively minor (see Table 4.2-4 in the EIR for the LARIC project).

The hydrocrackers and hydrotreating units are being modified to recover more ultra-low sulfur diesel (ULSD) and accept the lightest portions of the feeds that are currently processed in the Carson and Wilmington FCC units. These modifications allow the shutdown of the Wilmington FCC and the elimination of the emissions associated with the operation of the Wilmington FCC. Since the capacities of the cokers are not increasing and the FCC capacity is decreasing, the amount of heavy low gravity crude that the refinery can process will also not increase as a result of the LARIC project.

The average gravity of crude processed will also not increase because the LARIC project's refinery **product** slate would shift somewhat, producing less gasoline and more distillate. FCC units primarily produce gasoline, while hydrocracking units can be operated to produce primarily distillates. The production of more distillate and less gasoline requires less energy, resulting in a lower GHG footprint. Data in the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS) lookup table lists the GHG footprint of CARBOB as 99.18 gram (g) CO_2/megajoules (MJ) and that of ULSD as 98.03 g CO_2/MJ. ULSD has a higher molecular weight than gasoline, so less "cracking" or molecular weight reduction is required to produce diesel from heavy crudes than to produce gasoline from heavy crudes. The modifications to the Tesoro hydrocrackers would allow this shift to less gasoline and more distillate.

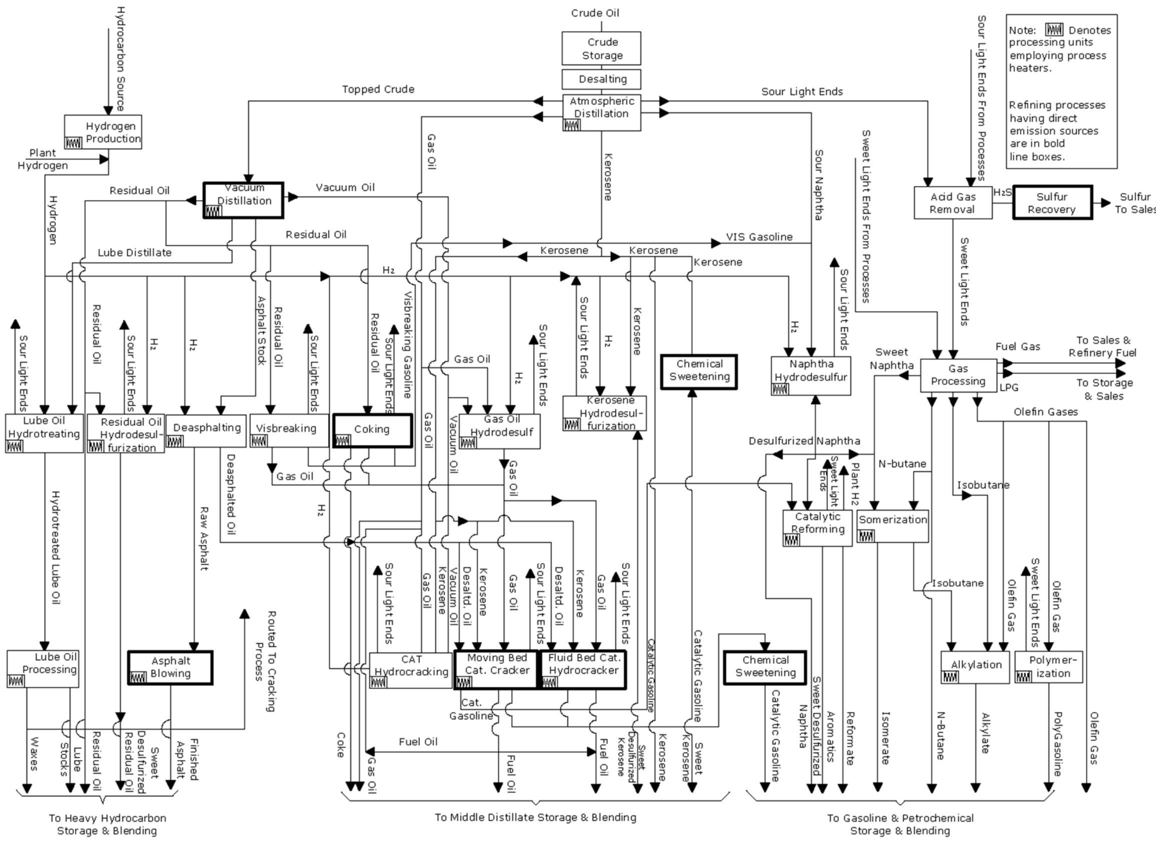
Hydrocrackers that produce distillate rather than gasoline also consume less hydrogen in the cracking reactions because the molecular weight reduction is smaller.

The capacity of the naphtha reformers will not change as a result of the LARIC project. The "lifting" capabilities of the crude units will not increase, so the amount of light, high gravity crude that the refinery can process will also not increase as a result of the LARIC project.

B. **What Crudes are Currently Delivered to the Tesoro Los Angeles Refinery?**

The Wilmington and Carson refineries were originally designed to refine California crude oils. The Carson refinery was later expanded to also refine Alaskan North Slope Oil and other imported crude oils. Because of the declining production from the Alaska and California oil fields and the captive use of this production by the various producers, Tesoro currently buys crude on the open market as a substitute for the original design crude oils in accordance with the information generated by the LP model. Some of this purchased crude is domestic production and some is imported from as far away as the Middle-East. According to U.S. DOE information, West Coast refineries processed 877 million barrels of oil in 2014. A little over half of this crude oil was imported into the U.S. and about 10% came from Canada.

Figure 3: Schematic of a Complex Oil Refinery

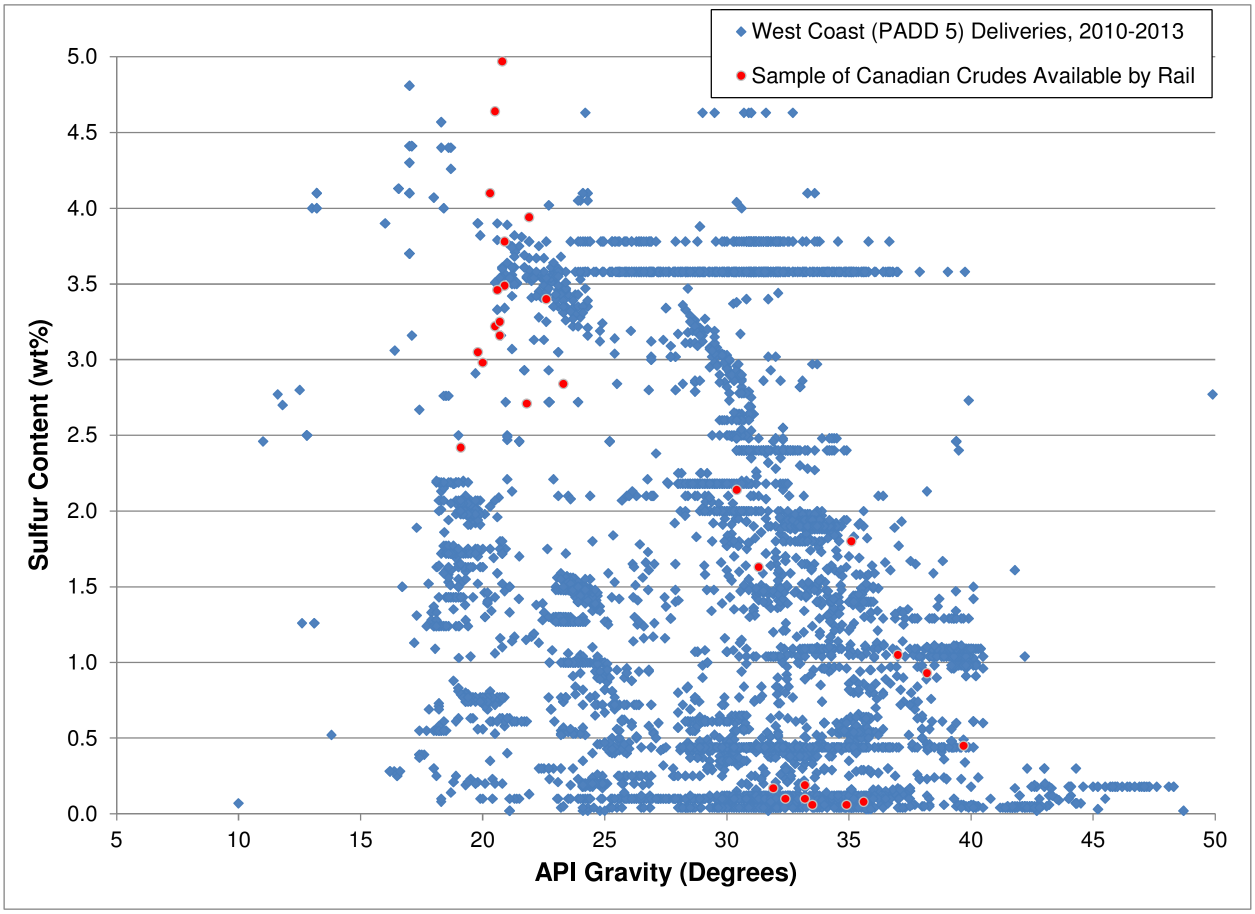


Source: EPA AP-42, Chapter 5 Petroleum Refining

The Energy Information Administration of the US Department of Energy publishes much information concerning the types of crudes that are imported into the US, produced within the US and processed within US refineries. The information, however, is aggregated to avoid revealing the input to individual refineries. DOE recognizes that the crudes purchased and processed by individual refineries is valuable company confidential information and does not release this information.

Figure 4 shows the gravity and sulfur contents of crudes that have been delivered to West coast (PADD 5) refineries in the recent past, along with the same properties of various Canadian crudes that could be available as reported by Crude Oil Quality, Inc.

Figure 4: West Coast Refinery Crude Quality



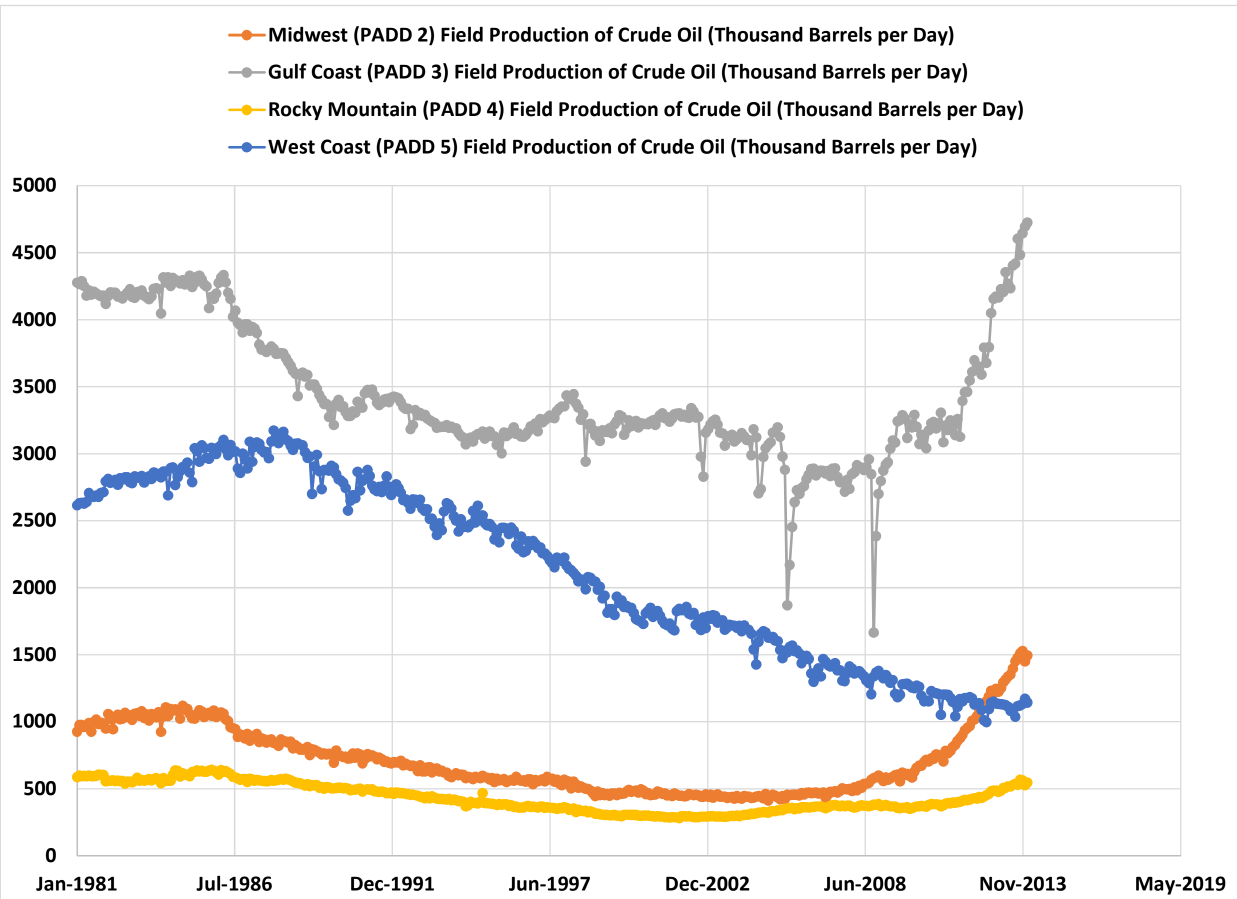
Tesoro Los Angeles currently receives some California and other crude oils via pipeline. It also receives both light sweet and heavy sour crudes via ship. The Tesoro Los Angeles Refinery does not have facilities to receive crude by rail and the LARIC project will not change modes of importing crude to the refinery so the slate of available crude oils will not change. The processing of these various crudes within the refinery is scheduled to match the operating constraints of the refinery.

C. What Crudes Will Be Delivered to the Los Tesoro Angeles Refinery as a Result of the LARIC Project?

The major operating constraints of the refinery are not being changed by the LARIC project. The ability of the crude units to "lift" more light material is not being increased. The ability to convert heavier crude fractions into lighter products is not increasing. The sulfur removal capabilities of the refinery are not increasing, so the **limits** in the quality of the crude blends that can be processed within the refinery will not change. The sources of the crudes actually purchased can change and the refinery will still have the ability to run "below the existing physical constraints". The actual **average** crude quality that the refining complex can run in the future will not change significantly.

In recent years, increasingly large volumes of crude oil have become available both domestically and from Canada. Processing more "local" crudes decreases the cost and carbon footprint associated with transporting crude oil to a refinery. Figure 5 shows historic crude oil production rates from various parts of the US. It is easy to see that West Coast crude production continues to decline while production from the mid-continent and gulf coast of the US is rapidly increasing. This increased production is mostly lighter crudes such as Bakken, WTI and WTS. This new production has upset the world crude oil market and resulted in a significant and unanticipated reduction in crude oil prices throughout the world, changing the relative values of different crudes.

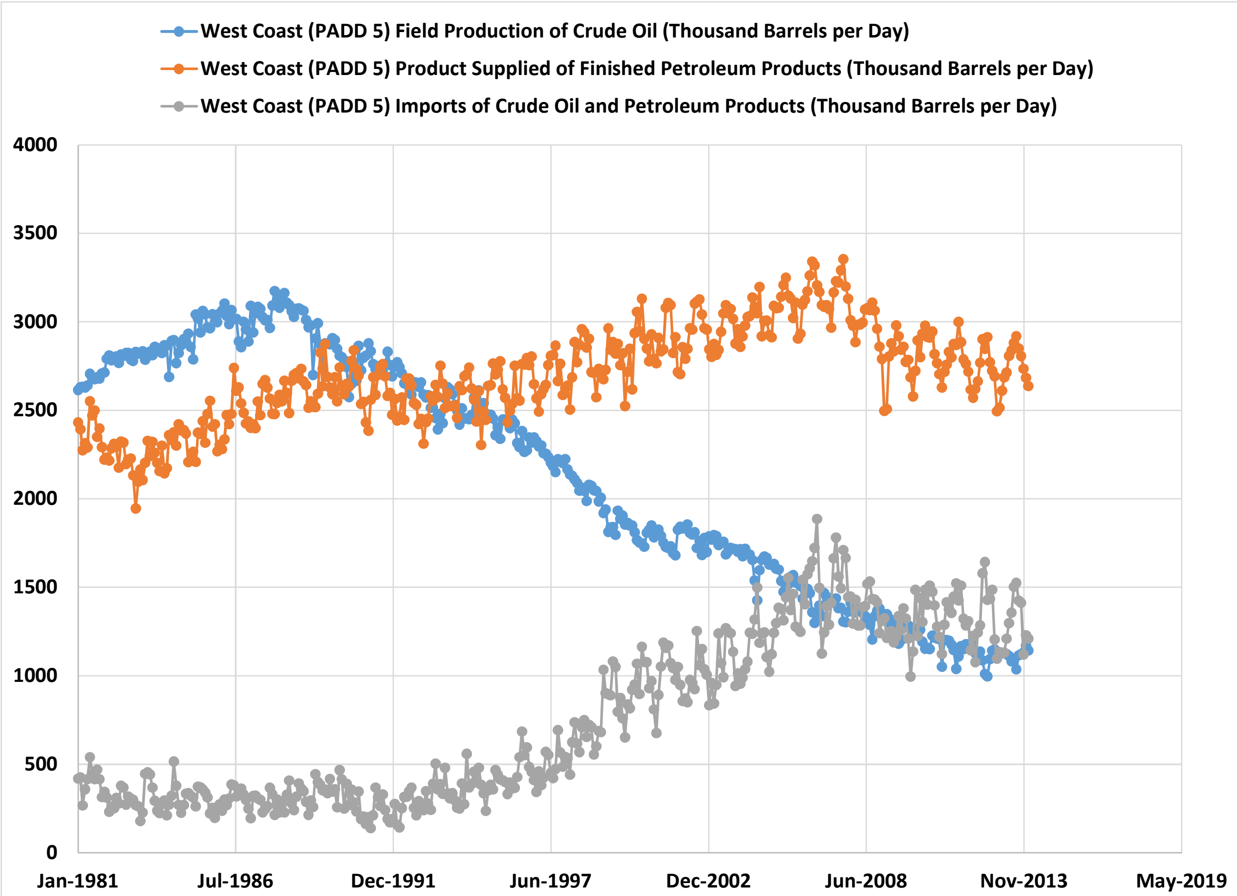
Figure 5: US Crude Oil Production



Through the mid-1990's PADD 5 was a net exporter of oil products to other parts of the US, Figure 6. Since then, the west coast and especially California has been a net importer of petroleum. Much of this oil has come from other countries.

The Tesoro Los Angeles Refinery currently receives crude oil by pipeline and by marine vessel at the Port of Long Beach. The LARIC project will not change the mode of transportation by which the Tesoro Los Angeles Refinery receives crude oil. The LARIC project does not include construction of new facilities to receive crude oil by rail. Tesoro will continue to receive crude oil by pipeline and waterborne cargoes. The size of the crude oil storage tanks that receive waterborne crude will increase, but as will be discussed in a subsequent section, this change in storage capacity will not impact the types of crudes that can be imported and processed and is expected to actually decrease VOC emissions associated with crude oil reception (during vessel hoteling in the port) and transfer. The sources of crude available by pipeline are currently and will continue to be determined by the pipeline operators. Tesoro's crude oil purchase decision mechanism based on LP modeling of the refinery will not change as a result of the LARIC project.

Figure 6: PADD 5 Petroleum Balance



II. Would Any Changes in Crude Sources Result in Increased Emissions?

There are several potential sources of emissions from an oil refinery:

- Point source emissions from furnaces and other process stacks. These point source emissions operate under and are limited by emission permits. Stack permits are being modified, which have the potential to increase emissions, but the shutdown of the Wilmington FCC more than offsets these minor increases. Although the processing capabilities of some of the other units are increasing, this is mostly being accomplished via energy efficiency improvements. As explained in the EIR, additional heat exchangers are being added to several units. These heat exchangers recover heat that is currently rejected and use it to provide additional capacity in some of the various conversion and separation processes in the refinery. These new heat exchangers will improve the overall energy efficiency of the complex.
- Fugitive emissions from pumps, valves, flanges, etc. The slight (~2% or up to 6,000 barrels per day) increase in potential crude processing rate will slightly increase the net

flow through much of the refinery piping and increase the potential for higher fugitive VOC emissions. The potential for fugitive VOC emission increases from higher flow rates is very small. New and modified VOC emission sources are subject to best available control technology (BACT) requirements, so fugitive VOC emissions from the LARIC project would be controlled via use of low leakage types of equipment, using welded connections in place of flanges and properly sealing flanges if weld joints are not possible. An active and effective leak detection and repair (LDAR) program pursuant to SCAQMD Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, also reduces VOC emissions from potential fugitive VOC sources. As discussed above, the type of crude oil processed is not expected to be lighter or have higher vapor pressure. Furthermore, the refinery will be producing less gasoline and more distillate, so the vapor pressure of the average product mix and the material moving through the piping system within the refinery will decrease, lessening the potential for VOC emissions.

- VOC emissions from crude storage tanks during filling and unloading. New or modified crude storage tanks would also be subject to BACT requirements, so fugitive VOC emissions would be minimized by use of closed tank vent systems, vapor recovery systems, floating roof tanks for medium volatility oils and pressurized tanks for high volatility material. Replacing several smaller fixed roof tanks with fewer, larger internal floating roof tanks will decrease VOC emissions from the transfer operations. However, the analysis in the EIR did not take credit for VOC emission reductions during crude transfer, so, overall the EIR shows an increase in fugitive VOC emissions from the new tanks (see EIR Table 4.2-4).
- VOC emission from LPG rail car unloading facilities. LPG rail car unloading facilities will be modified at Carson Operations to allow increased deliveries of approximately 4,000 bbl/day of Alkylation Unit feedstocks (LPG including propane, propylene, etc.). The increase in VOC emission caused by the increase in LPG imports and exports from the complex is addressed in the EIR (see EIR Table 4.2-4).

As already noted, the sources of crude oil currently received by the Tesoro Los Angeles Refinery constantly change based on a variety of factors and are expected to continue changing regardless of whether or not the LARIC project is implemented. However, the average gravity and sulfur contents of the future crude mix must still fall within Tesoro's existing feasible operating window. Figures 2-6 and 2-7 in the EIR (attached as Appendix B) show the blended crude API gravity and sulfur contents of the crude oil blends that have been processed in the Carson and Wilmington Operations of the Tesoro Los Angeles Refinery in the three years from 2012 to 2014. The Tesoro Los Angeles Refinery has 4 different crude units with different capabilities, three crude units in Carson and one in Wilmington. The Wilmington coker also processes some crude oil, so there are 5 different units that can each process crude oil directly. Each of the 5 units has different crude throughput and lifting capabilities as well as different metallurgy to handle different levels of sulfur and acidity.

During the past three years, the Tesoro Los Angeles Refinery complex processed some crude oils with sulfur contents over 3 wt% and API gravities ranging from 10 to 35. Although this is a very wide range of properties, physical unit limitations and economic considerations resulted in average total crude oil properties for that period of slightly under 28 API and about 1.5 wt% sulfur. Based on U.S. DOE data, the average crude oil processed by west coast refineries during the same time period was about 28 API and 1.4 wt% sulfur. The average crude oil input quality to the Tesoro Los Angeles refinery is in line with other west coast refineries.

Tesoro Los Angeles's configuration of process units determines the range of crude oil qualities that can be processed in the facility. As discussed above, its ability to remove sulfur from the various refinery products and air pollutant emission streams limits the maximum sulfur content of the total crude oil blend that can be processed to about 1.8wt%. Processing blends with less than about 0.5 wt% sulfur although feasible causes inefficient operation of the refinery's equipment and is unlikely to occur.

The Tesoro Los Angeles Refinery must also operate within a relatively narrow range of blended crude gravities. At full crude rate, the Tesoro Las Angeles refinery must operate with an average crude API gravity between 23 and 32 API. Each of the 4 crude units can individually run crude outside this envelope, but the weighted average crude quality must stay within these bounds at full crude rate. The refinery can also run lighter or heavier crude mixes at a reduced rate.

The capacities of the coker and FCC, as determined by the physical constraints of the operating equipment, limit the amounts of heavy crude with high quantities of low gravity tar-like substances that can be run without producing excessive amounts of very low value heavy fuel oil. The capacities of these units determine the ability of the refinery to convert these tar-like crude fractions into specification gasoline and distillates. Excess low gravity material must be blended with distillate and exported as high sulfur heavy fuel oil. Not only is the world market for high sulfur heavy fuel oil continuing to decline, producing high sulfur heavy fuel oil reduces distillate production making the production and sale of high sulfur heavy fuel oil very unprofitable.

The rated capacities of the naphtha reformers at the Tesoro Los Angeles Refinery are not being increased. The lifting capabilities of the atmospheric distillation portions of the crude units are also not being increased. Therefore, additional light crudes cannot be processed effectively. Crude oils with higher API gravity will contain more naphtha and distillates that must be distilled (lifted) from the crude oil. Furthermore, the naphtha must be upgraded in a naphtha reformer. Since the LARIC project does not change the capacity of the refinery's naphtha reformers, the refinery will not have the capacity to recover or upgrade additional naphtha. Furthermore, the impending Tier 3 gasoline sulfur regulations could require processing additional cracked naphtha in the light HDS units reducing their capacity to desulfurize naphtha recovered from crude oil. Crude blends with lighter gravities can exceed the capacity of the naphtha reformers and light stream hydrodesulfurization units at full refinery utilization. The refinery must then either export the excess intermediate streams to other refineries at distressed prices or reduce crude run to bring the refinery back into balance. Both of these options reduce refinery profitability and are highly unlikely.

Even though the “hard” operating limits are defined by physical equipment limitations, most of the actual crude blends that have been processed in the past three years at the Tesoro Los Angeles Refinery are well within these limits. The refinery requires some amount of operating “cushion” to ensure that it does not violate any true operating permit limits or other hard physical constraints such as tower flooding. Furthermore, operating at a minimum or maximum sulfur or gravity “limit” does not always produce the most profitable operation. The optimal crude mix, as determined by the LP model, is a function of the price and availability of various crudes as well as the price and demand for the various products.

Dilbits are a class of heavy crudes that have been available on the world market for more than 40 years, have been processed in many US refineries including some of the west coast refineries and are sold under a variety of names. They are one of many types of heavy, high sulfur crudes that are available throughout the world. They are produced as a blend of a high gravity, low viscosity diluent (dil) and a low gravity, high viscosity bitumen (bit). The diluents range from natural gas condensates to light sweet crudes such as Bakken. Dilbit are nothing more than pre-blended crudes to adjust overall properties to facilitate transport and refining. Most dilbits are shipped by pipeline, but some are also transferred to tankers for waterborne shipment. Of the approximately 1 billion barrels of Canadian crude imported into the US in 2014, only about 7% or just over 200 thousand barrels per day went to all of the west coast refineries combined, including those outside of California.

Large volumes of Bakken-type crude have recently become available from the north central United States and southern Canada. Unlike the heavy, high sulfur Canadian crudes, the Bakken crudes are light, sweet (low sulfur) crudes. Currently, most Bakken crude is shipped by rail. Since the Tesoro Los Angeles Refinery does not have facilities to receive crude oil by rail, it is unlikely that this refinery will process large volumes of Bakken crude. It must first be transferred to pipelines or ships or barges to be received by the refinery. Furthermore, as stated earlier in the report, the LARIC project will not allow the refinery to process a significantly lighter crude slate. Even if Bakken type crudes are available to the refinery, they could not be processed in volumes that would impact the average crude properties.

Neither Bakken, nor the heavy Canadian crudes could be profitably run by themselves at the

Tesoro Los Angeles Refinery. The refinery could not run at full capacity on either crude alone. When running pure Bakken, the refinery would be limited by its ability to lift and process the amount of naphtha contained in the crude and the units designed to process the heavy portion of the crude would be under-utilized. When running pure heavy Canadian crude, such as Christina Dilbit or Western Canadian Select, the refinery would be limited in its ability to handle the sulfur and residue in the crude and the units designed to process the lighter portions of the crude would be under-utilized. Information provided by the LP model is designed to avoid both of these scenarios.

All refinery units have minimum practical as well as maximum permitted operating limits. If a unit reaches its minimum operating limit it must be shut down. Thus, there are limits to how light or heavy a crude mix any refinery can run. Crudes like Bakken or heavy Canadian crudes, e.g., Western Canadian Select or Christina Dilbit, must be blended together with other crudes to optimize the refinery operation. By blending these crudes with other crudes, the refinery can run more efficiently and profitably at higher sustained rates than on either crude alone.

Table 1, extracted from a presentation given by John Auers of Turner, Mason & Co. at the Platts Crude Marketing Conference in Houston, TX on March 1, 2013 shows how two crude oils, with vastly different properties can be blended together to approximate the properties of a third crude oil. Table 1 shows how a blend of Western Canadian Select and Bakken crudes can give the same yields of the various refinery intermediate streams as Alaskan North Slope (ANS) crudes. Thus, refineries that were designed for ANS can substitute blends of WCS and Bakken for ANS. This table also shows that the light hydrocarbons (those contributing most to VOCs) in the blend are lower than those in ANS. Although the sulfur content of the blend is higher, this blend, if processed would only be a portion of the total crude fed to the refinery and the balance of the crude must be lower sulfur to remain within the appropriate limits.

Table 1: Crude oil comparison

Yield, vol%	Alaskan North Slope	WCS/Bakken Blend
API Gravity	32.1	32.1
Sulfur, wt%	0.9	1.4
TAN, mgKOH/g	0.6	0.1
Butanes and Lighter	4	3
Naphtha	26	26
Kero/Diesel	27	27
Gas Oil (FCC feed)	27	27
Residue (Coker feed or Asphalt)	16	16

Concerns have been raised for other refinery projects in California that any refinery project might allow an increase in the benzene content or the acidity of the crudes run in the refinery or potentially increase the VOC emissions from lighter crudes. The benzene content of Alaskan North Slope, a high volume west coast crude, has been reported as 0.33% while two Canadian crudes suspected of having elevated benzene contents (Figures 1 and 2) on average actually have a lower benzene content than ANS. Crude Oil Quality, Inc. also reports the benzene content of Canadian light sweet crudes as less than 0.25%, again less than ANS, a high volume west coast crude. The benzene content of gasoline is limited by law. The Tesoro Los Angeles Refinery has a benzene saturation unit to reduce the benzene content of the finished gasoline. Like all refinery units, the benzene saturation unit has processing limits which are not being modified by the LARIC project. Thus, the refinery cannot substantially increase the amount of benzene it receives as input to the refinery.

The acidity of the Canadian crudes is also lower than that of typical California crudes and other heavy sour crudes. As noted earlier, the Carson and Wilmington Operations were originally designed to process California crudes. San Joaquin Valley crudes have acidities above 2 (as shown in the California Energy Commission report attached as Appendix C), while Figures 1 and 2 show values below 2 for heavy Canadian crudes. The acidity of the light sweet Canadian crudes is not reported because of its low value. Tesoro actively monitors and controls the acidity of the crudes it purchases and the blends it processes to stay within equipment capabilities. Tesoro also conducts an equipment inspection program that exceeds state and federal requirements. A more detailed explanation of the Tesoro corrosion monitoring program is included in Appendix D.

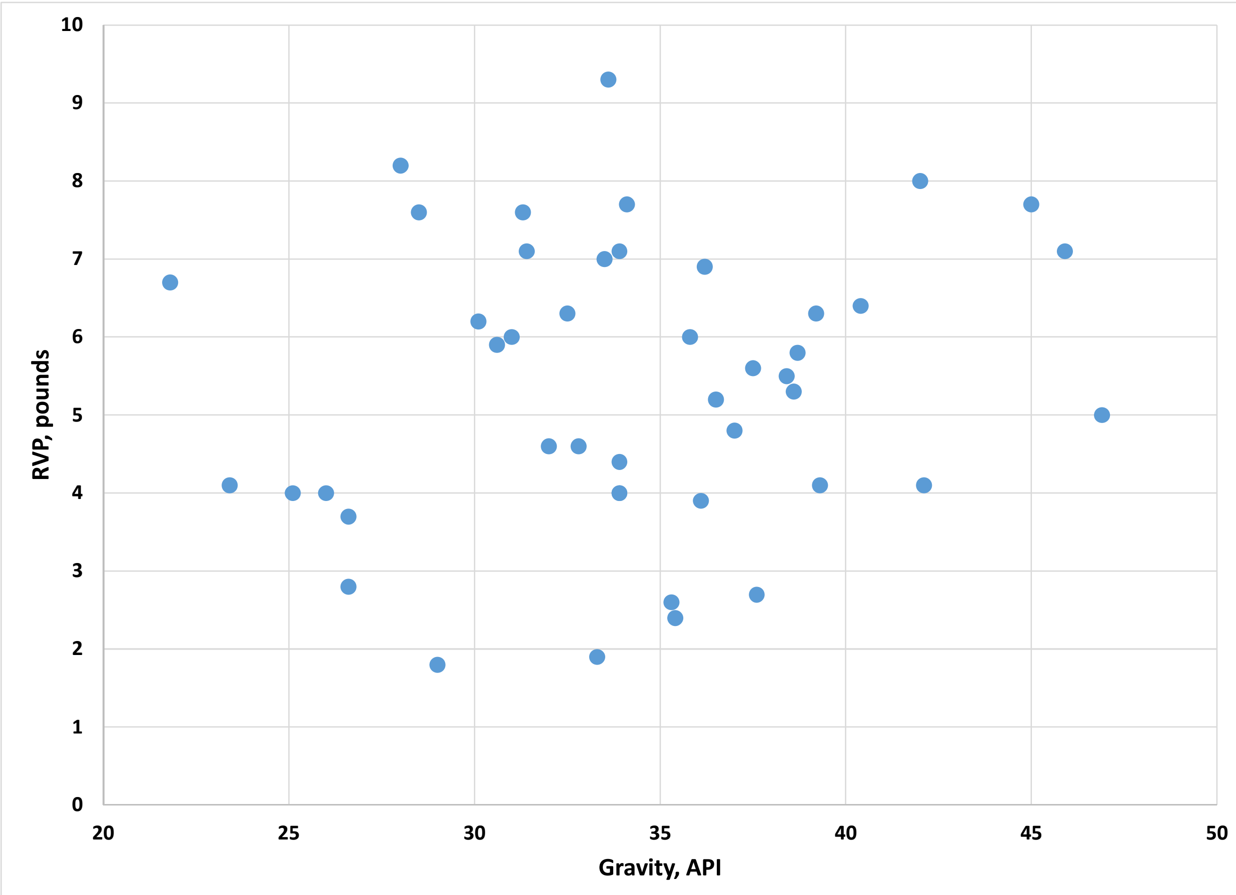
Crude oil volatility (vapor pressure or potential VOC emissions) has recently received increased scrutiny by various governmental agencies. Most of the focus has been on proper labeling/classification of crude oil shipped by rail from the Bakken formation and the use of proper rail cars for transport. Crude oil is a flammable liquid as defined by the Code of Federal Regulations (CFR) Title 46 (30.10) for Marine shipments and Title 49 (172.101) for land and air shipments. Both CFR sections define three subclasses of flammable liquids although the definitions are slightly different. Title 46 defines Grades A, B and C based on Reid Vapor Pressures (RVP, ASTM D323) of > or = to 14 pounds, under14 and over 8.5 pounds and less than or equal to 8.5 pounds, respectively. Title 49 defines three Packing Groups based on initial boiling point by ASTM D86 distillation and flash point. These are: Packing Groups I, II and III based on IBP<95 F (PG I), IBP >95F and Flash Point <73F (PG II) and Flash Point >73F and <149F and IBP>95F (PG III).

In addition to these shipping requirements, refiners also limit the volatility of crude they purchase. Most of the volatility or vapor pressure of crude oil is due to the small amounts of propane, butanes and pentanes (light paraffinic hydrocarbons) that are dissolved in the crude oil. Refineries are very limited in their ability to convert these light paraffinic hydrocarbons into gasoline. CARB gasoline has a Reid Vapor Pressure (RVP) limit of 7 pounds, so much of the light paraffinic hydrocarbons contained in the crude oil must be sold at a loss as LPG. Wholesale LPG spot prices are typically much less than CARB gasoline prices, providing an economic incentive for Tesoro to control the vapor pressure of the crude it purchases.

Tesoro is expanding their facilities to unload additional quantities of higher value olefinic light hydrocarbons (propylene and butylenes). These olefinic light hydrocarbons can be upgraded to a high value CARB gasoline blending component in the alkylation unit. The shutdown of the Wilmington FCC unit reduces the amount of light olefins produced in the refinery. Both olefinic and paraffinic light hydrocarbons are often called LPG, although they have much different values.

There is no universal relationship between crude gravity and volatility or vapor pressure of the crude oil as shown in Figure 7 for 45 different crude oils. Based on the factors discussed above, there is no valid reason to believe that the crudes that arrive after the LARIC project will be higher volatility than those currently processed. Tesoro has financial incentives to minimize the volatility of crudes that it purchases.

Figure 7: Crude oil volatility



As discussed in the EIR, the replacement of smaller crude oil storage tanks with new larger tanks will decrease the time required to unload a tanker and reduce hoteling emissions from the tanker during the overall unloading process. Of potential concern is whether or not these larger tanks will reduce the ability of the refinery to optimize crude purchases and therefore result in lighter or heavier average crude slates. It is my opinion that the larger tanks will not impact the ability of the refinery to blend various crudes to meet the refinery targets as explained below.

These new larger tanks only impact the waterborne crudes that arrive by tanker or barge. These are generally large cargoes that are purchased in advance, allowing the refinery adequate time to plan for their arrival and purchase complementary crudes. As explained in the EIR, the cargo size is set by the vessel size, not the tank size. The larger tanks will make the vessel unloading more efficient while not changing refinery operations.

The LARIC project will replace several fixed roof crude oil storage tanks that are currently connected to a vapor recovery system and are considered BACT with internal floating roof tanks. Although both tanks are considered BACT, the internal floating roof tanks generally generate lower VOC emissions than fixed roof tanks. The lower emissions were not fully comprehended in the overall VOC emissions estimates in the EIR.

The proposed LARIC project is not expected to result in changes to the future crude slate processed in the Tesoro Los Angeles Refinery compared to what is currently processed at the refinery. Therefore, the average sulfur content and acidity of the crude is not expected to increase. These are the most corrosive elements of the crude, so there should be no increased risk of equipment failure due to corrosion.

The Wilmington FCC unit is a complex, circulating fluidized bed process unit. Although a typical FCC unit has few upsets, it has a relatively higher probability of upset than typical fixed bed units. Shutting down the Wilmington FCC unit will eliminate the overall risk of upset from this unit.

The operation of the hydrocracking units is being modified to decrease naphtha yield and increase distillate yield. It is well known to those in the industry that hydrocrackers that produce distillate are less at risk for upsets than those that produce naphtha. The analysis of risk of upset impacts from the modified hydrocracking units at both the Carson and Wilmington Operations concluded that hazards associated with the proposed modifications would result in a reduction in hazard impacts (see EIR Table 4.3-2).

The installation of the sulfuric acid regeneration unit will definitely reduce the risk of potential releases of fresh and spent sulfuric acid during the transport outside the refinery, because spent sulfuric acid would be regenerated and reused onsite, thus, eliminating fresh and spent sulfuric acid transport trips as explained in the EIR.

What Information Must Tesoro Keep Confidential?

Preparation of this report relied on information included in the EIR, as well as other publicly available information. Some additional information was provided to the author by Tesoro Los Angeles Refinery as business confidential information. Some information is copyrighted information with restrictive rights that limit its public dissemination without proper compensation. The following information is treated as business confidential:

- The specific North American crudes that Tesoro plans to purchase;
- The properties (weight, sulfur content, vapor pressure, and acidity) of specific crudes delivered to Tesoro in the past;
- The properties (weight, sulfur content, vapor pressure, and acidity) of specific crude blends processed at the refinery;
- Data purchased by Tesoro showing the weight and sulfur content of specific crudes, including North American crudes;

- Data generated by Tesoro showing the weight and sulfur content of specific crudes, including North American crudes;
- Detailed information regarding the weight and sulfur content of crude blends suitable for processing at the Tesoro Los Angeles Refinery based on the refinery's unique configuration; and
- Detailed daily measurements of the weight and sulfur content of crude blends processed at the Tesoro Los Angeles Refinery in the past.

Basic properties of most Canadian crudes such as gravity, sulfur, benzene and acidity are available on www.crudemonitor.ca. Representative data have been included in this report. Detailed properties on Bakken crude could not be found in public documents. Crude assay compositional data can be purchased from companies such as AspenTech; however, this information is copyrighted and cannot be distributed to the general public. Other detailed information concerning the capabilities of the various refinery process units, the crudes that have been and will be run in the refinery and the planning tools that the refinery uses to make crude purchase decisions, is also considered to be confidential and, thus, not publicly available.

As discussed above, the U.S. DOE has determined that refineries do not have to release specific crude purchase information to the public nor do they have to release detailed information on the capabilities of the various processing units within the refinery. It is sufficient to release only unit capacities aggregated by unit type. This information is available on the DOE website and also by purchase through the Oil and Gas Journal. Although the refineries report more detailed information on crude purchases to the DOE and CARB, the agencies aggregate the data prior to publication to avoid revealing company confidential information.

Crude oils are a commodity that is heavily traded by oil companies as well as trading companies. Publishing what specific crudes Tesoro purchases or intends to purchase allows competitor refiners to bid on similar crudes and allows traders to purchase futures of these crudes. Both of these actions would increase the price Tesoro would then pay for future cargoes of these specific crudes. Releasing information on the specific crudes that Tesoro intends to purchase would put it at a disadvantage against it competitors.

The planning tools that a refinery uses can be purchased by anyone; however, they are copyrighted and cannot be redistributed without compensating the copyright owner. Furthermore, much of the value of these programs comes from configuring them and customizing them to closely match the capacities, capabilities, limitations and performance of the individual units in a particular refinery. This latter type of information would be of particular value to a competitor and is business confidential information.

All of the conclusions and opinions set forth above are made to a reasonable degree of professional certainty.

Oct 12 2015
Date

Stephen J. McGovern, P.E., PhD

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Appendix A

Curriclum Vitae

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Stephen J. McGovern
912 Brandywine Drive
Bear, DE 19701
Cell: 856-371-3463
Email: sjmcgovern@hotmail.com

Transportation Fuels and Refining Technology Expert

Over 40 years of experience in many aspects of petroleum refining technology and management, especially Hydroprocessing, Catalytic Cracking, Biofuels, Economics and Emissions. Outstanding record of fundamental research, process/project development and implementation as well as technical service and technical training.

Experience Summary:

PetroTech Consultants 2000- present
Principal of consulting firm specializing in Petroleum and Biofuels Refining Technology
Mobil Corporation 1973-2000
Senior Technical Expert in Refining Process Technology with special emphasis on Catalytic Cracking, Hydroprocessing and reactor design and emissions. Past Manager of Corporate Hydroprocessing Research and Technical Service group. Provided world-wide technical service and troubleshooting, technical input into laboratory experimental programs and the process design of new commercial units along with environmental and economic advice.

Recent Accomplishments

- Member of two US National Research Council committees evaluating the economic and environmental impacts of increasing biofuels production and alternate vehicle and fuels technologies
- Provided technology guidance to DARPA for the production of HEFA type bio based jet fuels
- Provided technical guidance to several commercial bio and alternative fuels companies
- Provided process designs for several Hydrocracking and ULSD units.
- Developed design for commercial biofuels hydrotreater
- Coordinated technology evaluation pilot unit studies for multiple clients
- Prepared a detailed assessment of the US refining industry's capabilities to produce ULSD.
- Prepared a detailed technical and economic assessment of solid acid alkylation technologies
- Evaluated technical and economic feasibility for producing 10 and 30ppm sulfur gasoline.
- Diagnosed performance problems of commercial hydroprocessing and FCC units.
- Assisted client in troubleshooting and improving novel fluid bed technology.
- Consulted on FCC emissions issues
- Provided expert testimony for FERC on refining economics
- Prepared expert reports on refinery environmental and technical issues
- Currently teach several refining technology courses for Refining Process Services.

Education

Ph. D. Chemical Engineering, Princeton University, Princeton, New Jersey 1985
M. A. Chemical Engineering, Princeton University, Princeton, New Jersey 1982
M. S. Chemical Engineering, Drexel University, Philadelphia, Pennsylvania, 1976
B. S. Chemical Engineering, Drexel University, Philadelphia, Pennsylvania, 1973
New Jersey Professional Engineer, License No. 24GE26348

Other Accomplishments

Process Consultant, FCC and Clean Fuels Technology – Senior technical expert in refining process technology.

- Initiated the development of Mobil's Cyclofine FCC third stage separator technology.
- Initiated the development of Mobil's improved FCC stripper technology.
- Designed and coordinated an extensive FCC pilot unit program to better understand the effects of feed quality on FCC yields and product properties.
- Provided guidance to various refineries regarding Air Emissions Compliance and Testing.
- Managed the rapid commercialization of Mobil's Octgain process for producing low sulfur gasoline.
- Provided technical and economic guidance for several major FCC and HDP revamps.
- Provided on-site FCC turnaround and troubleshooting support.
- Provided "cold eyes" and Value Engineering reviews of major projects.
- Participated in several refinery yield improvement surveys.
- Evaluated adsorption technology for removing sulfur from gasoline.
- Responsible for overseeing Mobil's FCC and Hydrocracking modeling efforts.
- Improved the FCC and HDP representations in refinery planning and operational LP's.
- Developed process for upgrading Sasol's Fischer-Tropsch liquids.
- Commercialized Mobil's Xylene Isomerization technology

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Appendix B

Crude Oil API Gravity and Sulfur Content Graphs

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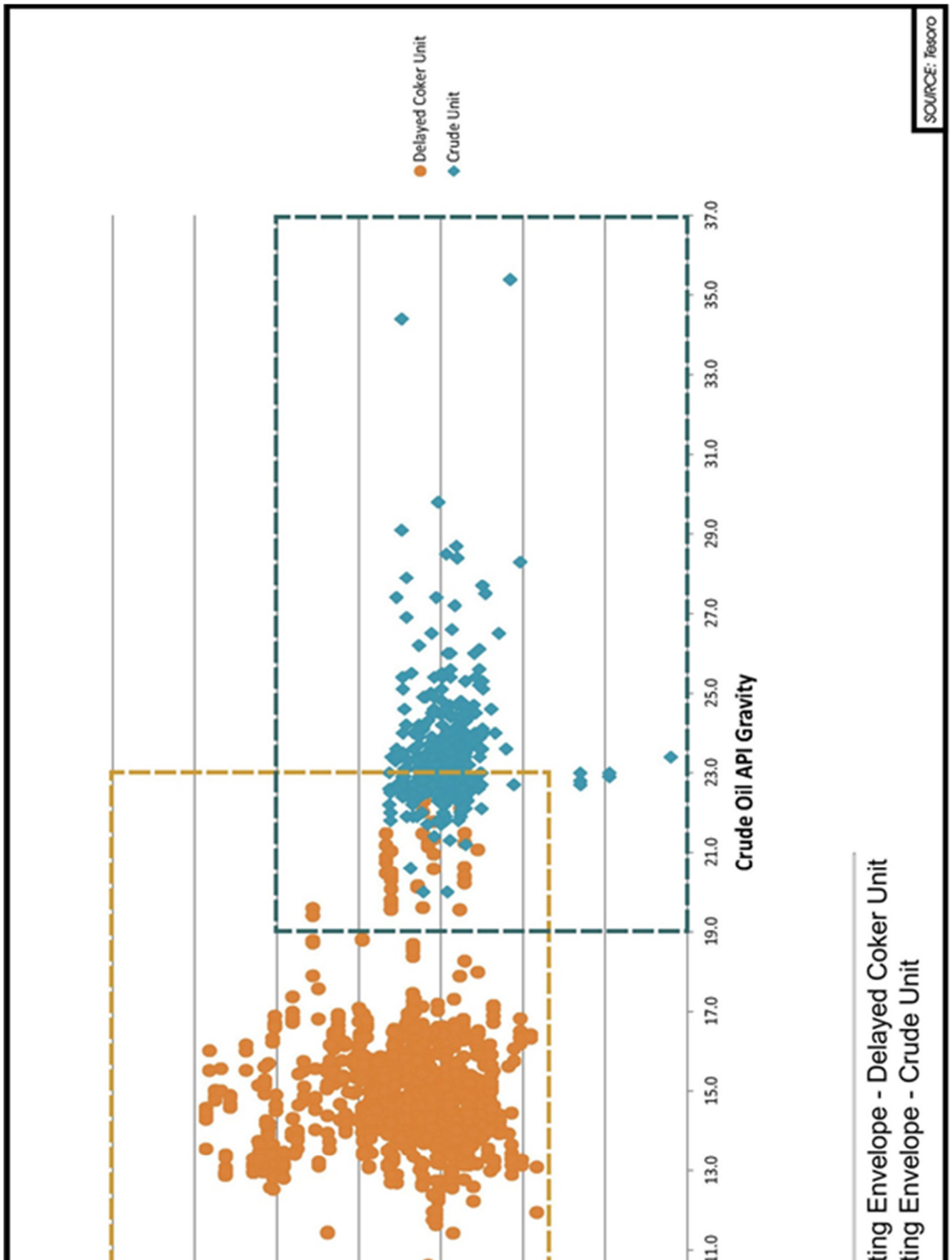

Environmental Audit, Inc.

FIGURE 2-6
OPTIMAL CRUDE OIL SLATES
WILMINGTON OPERATIONS
TESORO LOS ANGELES REFINERY

Project No. 2844

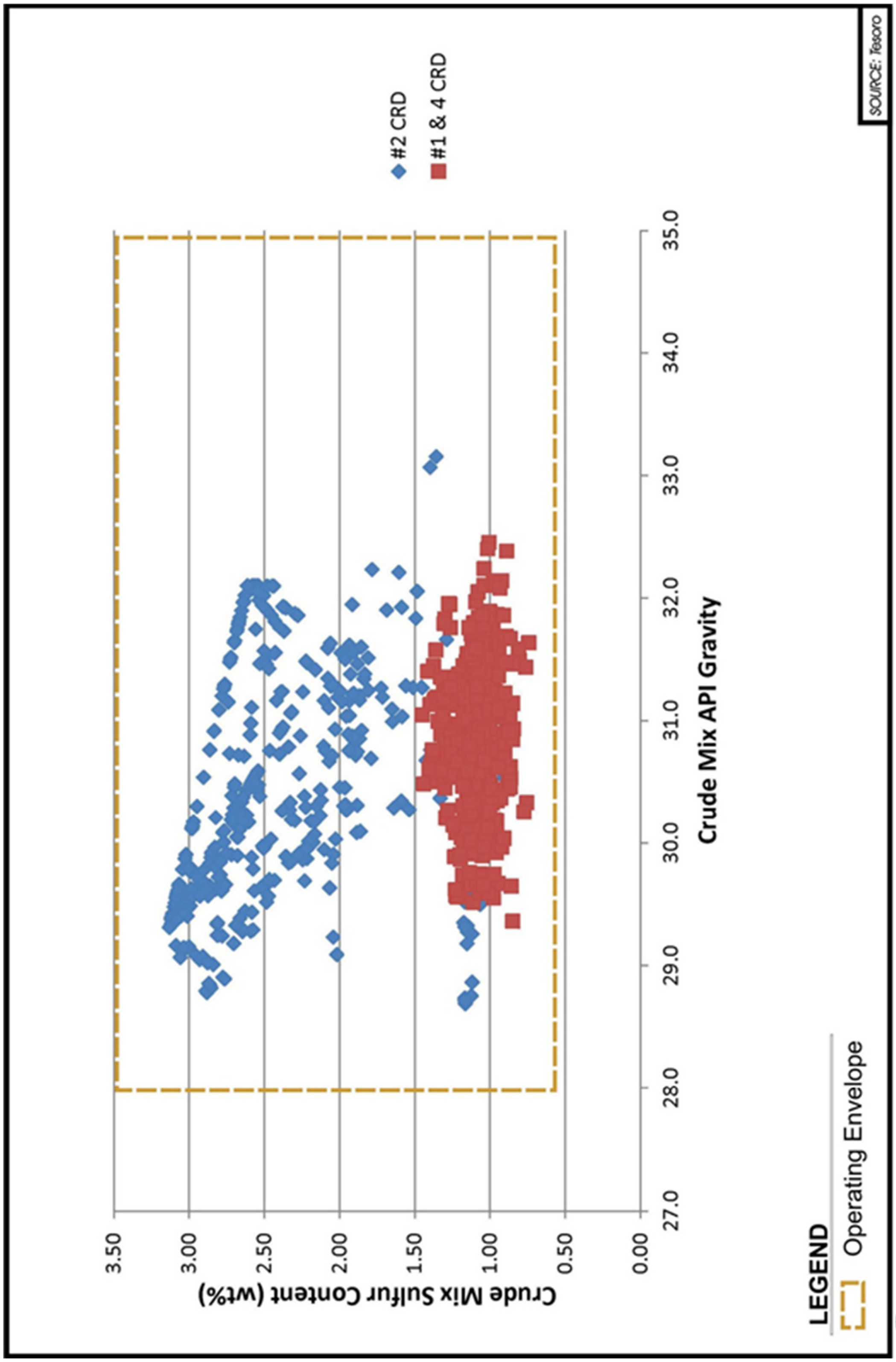

FIGURE 2-7
OPTIMAL CRUDE OIL SLATES
CARSON OPERATIONS
TESORO LOS ANGELES REFINERY

Environmental Audit, Inc.

Project No. 2844

Appendix C

California Energy Commission Report

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CALIFORNIA CRUDE OIL PRODUCTION AND IMPORTS

Margaret Sheridan
Fossil Fuels Office
Fuels and Transportation Division
California Energy Commission

DISCLAIMER

STAFF PAPER

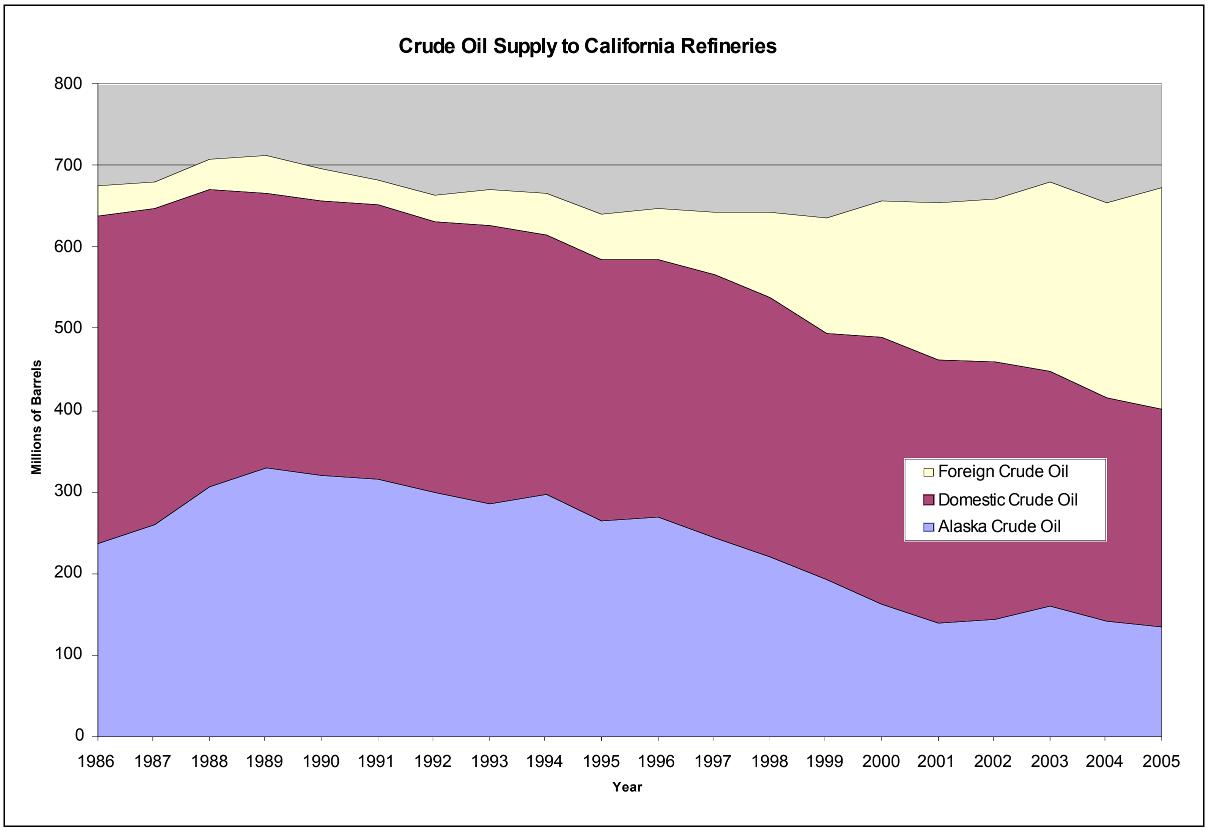
APRIL 2006
CEC-600-2006-006

CALIFORNIA CRUDE OIL PRODUCTION AND IMPORTS

Introduction

Californians consume nearly 44 million gallons of gasoline and 10 million gallons of diesel every day.[1] California refineries produce these fuels and other products from crude oil and blending components. Transportation fuel production in California depends on the availability and quality of the crude oils used by refineries in the state. Figure 1 shows the average annual refinery receipts of crude oil from 1986 to 2005. The supply of crude oil to California refineries has changed substantially in the last 10 years. Most notably, receipts of foreign crude oil have increased as production sources from California and Alaska have continued to decline.

Figure 1



Source: Petroleum Industry Information Reporting Act

Historically, California has been relatively self-reliant in petroleum supplies. However, crude oil production in California has decreased by 23 percent since 1996.[2] This decline of supply in the state has increased reliance on foreign and domestic imports. Starting in 1994, California refineries received more imported crude oil than in-state sources. In 2005, California crude oil accounted for approximately 37 percent of the total receipts.

The quality of the crude oil used by the refinery in conjunction with the complexity of processing units dictates the percentages of products produced. For example, lower quality crude oil is more difficult to refine into lighter products, such as motor and aviation gasoline. Refineries have minimum crude oil quality requirements that are determined by the processing units in the plant.

This paper presents information on crude oil characteristics, California crude oil production trends, and their possible impact on future transportation fuel production.

Crude Oil Characteristics

The quality of crude oil is determined by a number of characteristics that affect the proportions of transportation fuels and petroleum products produced when the oil is refined. The two most common measurements of crude oil quality are the specific gravity (which is measured in degrees) and the sulfur content of the oil. Acid content is also a factor in determining the corrosive properties of the crude oil entering the refinery.

Specific Gravity

The specific gravity is typically measured using the American Petroleum Institute (API) standard or the API gravity of the crude oil. The API gravity is the measure of the weight of crude oil in relation to the weight of water (water has an API gravity of 10 degrees). Crude oil is characterized as heavy, intermediate, or light with respect to its API gravity.

- Heavy Crude: Crude oils with API gravity of 18 degrees or less is characterized as heavy. The oil is viscous and resistant to flow, and tends to have a lower proportion of volatile components. Fifty one percent of California crude oil has an average API of 18 degrees or less.

- Intermediate Crude: Crude oils with an API greater than 18 and less than 36 degrees are referred to as intermediate. Forty eight percent of California crude oil has an average API between 18 and 36 degrees.

- Light Crude: Crude oils with an API gravity of 36 degrees or greater. Light crude oil produces a higher percentage of lighter, higher priced premium products.

Sulfur Content

Crude oil is defined as "sweet" if the sulfur content is 0.5 percent or less by weight and "sour" if the sulfur content is greater than 1.0 percent. Sulfur compounds in crude oil are chemically bonded to hydrocarbon molecules in the oil. Additional equipment in the refinery is required to remove the sulfur from crude oil, intermediate hydrocarbon feedstocks, and finished products. Transportation fuel specifications require extremely low sulfur contents, usually less than 80 parts per million (ppm).

Acid Content

Another characteristic of crude oil is the total acid number (TAN). The TAN represents a composite of acids present in the oil and is measured in milligrams (mg). A TAN number greater than 0.5 mg is considered high.[3] As an example, Wilmington and Kern crude oil have a TAN ranging from 2.2 to 3.2 mg, respectively.[4] However, some acids are relatively inert. Thus, the TAN number does not always represent the corrosive properties of the crude oil. Further, different acids will react at different temperatures – making it difficult to pinpoint the processing units within the refinery that will be affected by a particular high TAN crude oil. Nonetheless, high TAN crude oils contain naphthenic acids, a broad group of organic acids that are usually composed of carboxylic acid compounds. These acids corrode the distillation unit in the refinery and form sludge and gum which can block pipelines and pumps entering the refinery.[5]

The impact of corrosive, high TAN, crude oils can be overcome by blending higher and lower TAN oils, installing or retrofitting equipment with anticorrosive materials, or by developing low temperature catalytic decarboxylation processes using metal catalysts such as copper. Many California refineries already process high TAN crude. High TAN oils are sold on the market at a discount compared to higher quality crude oils.

High TAN oils account for an increasing percentage of the global crude oil market. Crude oil with a TAN greater than 1.0 mg increased in the world market from 7.5 percent in 1998 to 9.5 percent in 2003.[6]

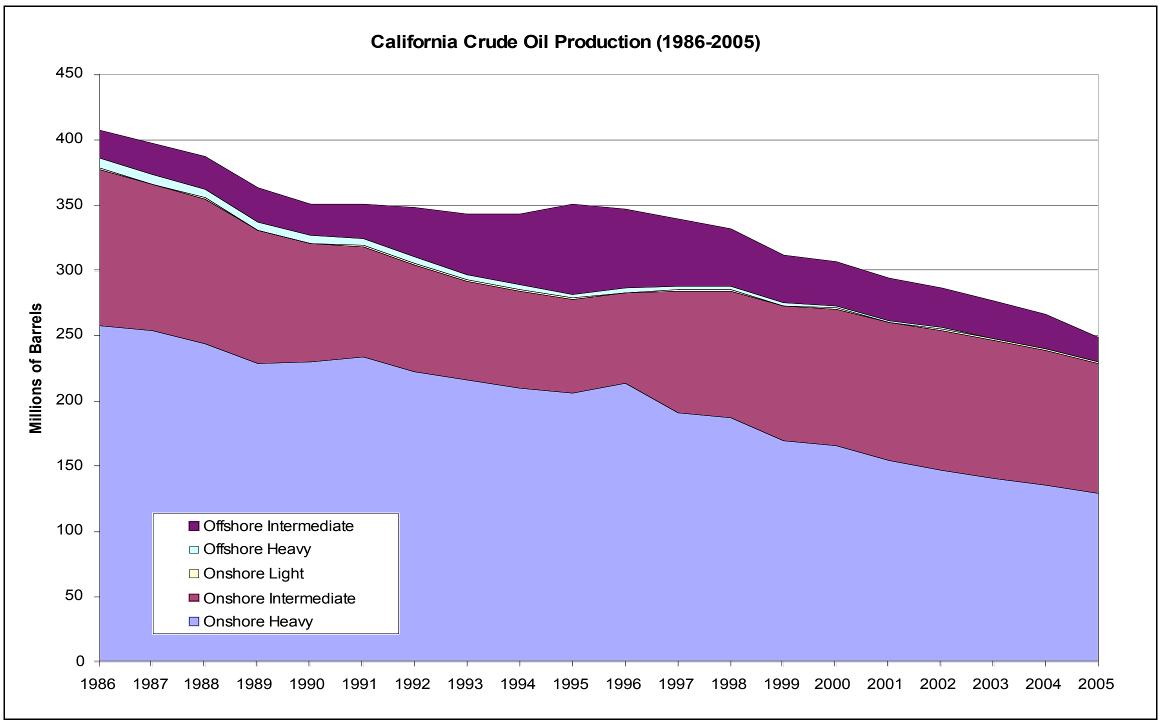
California Crude Oil Production

The discovery of oil in Kern County in the late 19th century heralded a long history of oil production in California. At the turn of the 20th century, crude oil was valued primarily for the heavier products and refining was oriented towards the production of heating oil and lubricants. In the early 1900s, with growing automobile use, gasoline became a more important commodity.

California is currently ranked fourth in the nation among oil producing states, behind Louisiana, Texas, and Alaska, respectively. Crude oil production in California averaged 731,150 barrels per day in 2004, a decline of 4.7 percent from 2003. Statewide oil production has declined to levels not seen since 1943.[7]

Figure 2 shows California onshore and offshore crude oil production over the last 20 years. The production of heavy, intermediate, and light crude oil production are broken out for onshore and offshore (or Outer Continental Shelf [OCS]) areas.

Figure 2



Sources: California Department of Conservation, Minerals Management Service

Production peaked in California in 1983. Production has declined at an average rate of 2.4 percent per year in the last 10 years.

Figure 2 shows a constant decline in onshore heavy crude oil production from 1986 through 2005 of 6.8 million barrels per year, or approximately 3.5 percent per year. Intermediate onshore oil production remained relatively flat. Offshore crude oil production peaked at 72 million barrels in 1995 and has declined by around 4.3 million barrels per year - or 10.2 percent per year - from 1995 through 2004.

The three major regions of California crude oil production are Kern County, the Los Angeles Basin, and the Outer Continental Shelf (OCS).

- **Kern County:** In 2004, oil from Kern County accounted for 77 percent of California's total onshore production and over 69 percent of the state's total oil production.[8] Approximately 58 percent of the crude oil has an API of 18 degrees or less. The Kern River oil field, located in the eastern San Joaquin Valley, accounts for approximately 24 percent of Kern County oil. Kern River oil is characteristically heavy and sour with an API of 13.4 degrees and a sulfur content of 1.2 percent.[9]

- **Los Angeles Basin:** The Los Angeles Basin is a sedimentary plain extending from central Los Angeles south through the Long Beach area. The two largest fields by area in this region are the Wilmington and the Huntington Beach fields with average APIs of 17.1 and 19.4 degrees, and average sulfur contents of 1.7 and 2.0 percent, respectively.

- **Outer Continental Shelf:**[10] The Federal Minerals Management Service oversees crude oil rigs located three nautical miles or greater from the coast. The OCS rigs accounted for 10.2 percent of the total California production in 2004. Many of these rigs are leased to commercial companies with pipelines extending to onshore processing facilities. The quality of OCS crude oil varies by field. Both sweet and sour OCS crude oils have API gravities ranging from 14 to 38 degrees.[11] Intermediate crude oil with an API gravity between 18 and 36 degrees accounted for 96.6 percent of the OCS production in 2004.

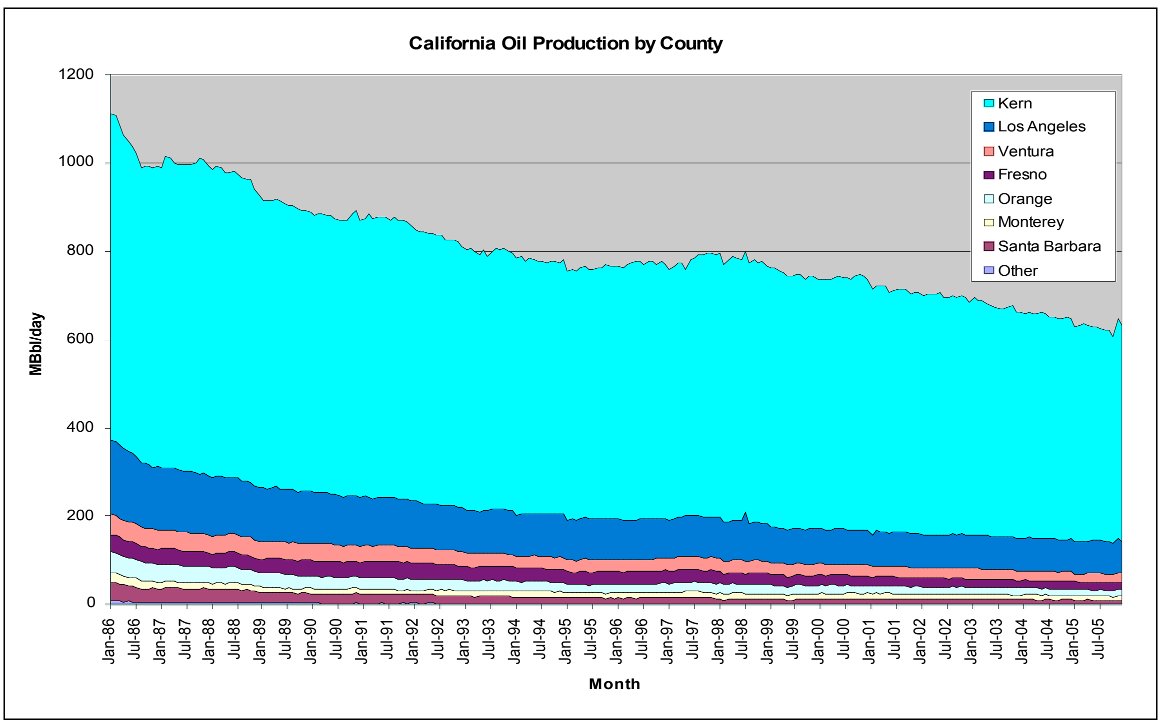
Table 1 shows an assay of selected California crude oils.[12] The table provides the percentages of 2005 production to show the relative importance of the field. The distillation breakdown of each crude oil provides a general guideline of the refining product suite that would result after the initial crude distillation has been completed. The actual ratio of finished refined products will vary depending on the complexity of the refinery. Note that unrecoverable gas losses occur in the assay, resulting in distillation product summations of less than 100 percent.

Table 1

County	Field	Percent of 2005 Production	API Gravity & Sulfur	Distillation breakdown (percent per volume) Total Gasoline & Naptha	Middle Distillates	Residuum	Lubes
Kern & San Luis Obispo	Midway Sunset	18.47%	12.6, 1.6%	0.00%	12.00%	50.30%	34.80%
Kern	Kern River	14.36%	13.3, 1.1%	0.00%	15.80%	56.10%	28.10%
Kern	Elk Hills	7.91%	34.6, 0.8%	34.30%	23.30%	25.00%	15.90%
Los Angeles	Wilmington	6.49%	17.1, 1.7%	9.50%	18.20%	52.80%	19.40%
Kern	Lost Hills	4.96%	18.4, 1.0%	7.60%	23.50%	42.70%	23.20%
Ventura	Ventura	1.75%	30.2, 1.0%	30.20%	20.80%	31.30%	16.30%
Kern	Belridge N. Lt.	1.63%	31.3, 0.3%	25.70%	25.70%	26.30%	20.90%
Monterey	San Ardo	1.52%	12.2, 2.3%	2.10%	14.50%	62.50%	20.50%
Los Angeles	Inglewood	1.24%	21.0, 1.8%	12.90%	27.60%	39.10%	19.40%
Orange	Huntington Beach	1.07%	19.4, 2.0%	12.00%	19.70%	48.90%	19.40%
Los Angeles	Long Beach	0.65%	25.0, 1.3%	18.90%	23.10%	40.60%	17.40%
Kern	Mount Poso	0.26%	16.0, 0.7%	0.00%	13.40%	52.00%	34.00%

Figure 3 shows the onshore production by county.

Figure 3



Source: Dept. of Conservation

California commonly uses Thermally Enhanced Oil Recovery (TEOR) techniques to help maintain crude oil production, because heavy, viscous crude oil requires heating to move the oil to the pump. Direct injection steaming and intermittent steaming are two types of TEOR. California crude oil production is also enhanced by injection of water (water flooding) and even carbon dioxide (CO_2) to help maintain sufficient pressure in the crude oil field. In the absence of more aggressive use of TEOR, California's crude oil production is expected to continue to decline at a rate of 3.5 percent per year through 2019.[13]

Well activity provides an indication of potential production in the state. In 2004, drilling increased to 2,451 wells, a 6.7 percent increase from 2003. The number of plugged wells decreased to 2,039 from 2,501 in 2003. Drilling and plugging activities in the state have fluctuated by more than 900 wells from year to year; however, the general trend is relatively flat.

Alaska North Slope Crude Oil

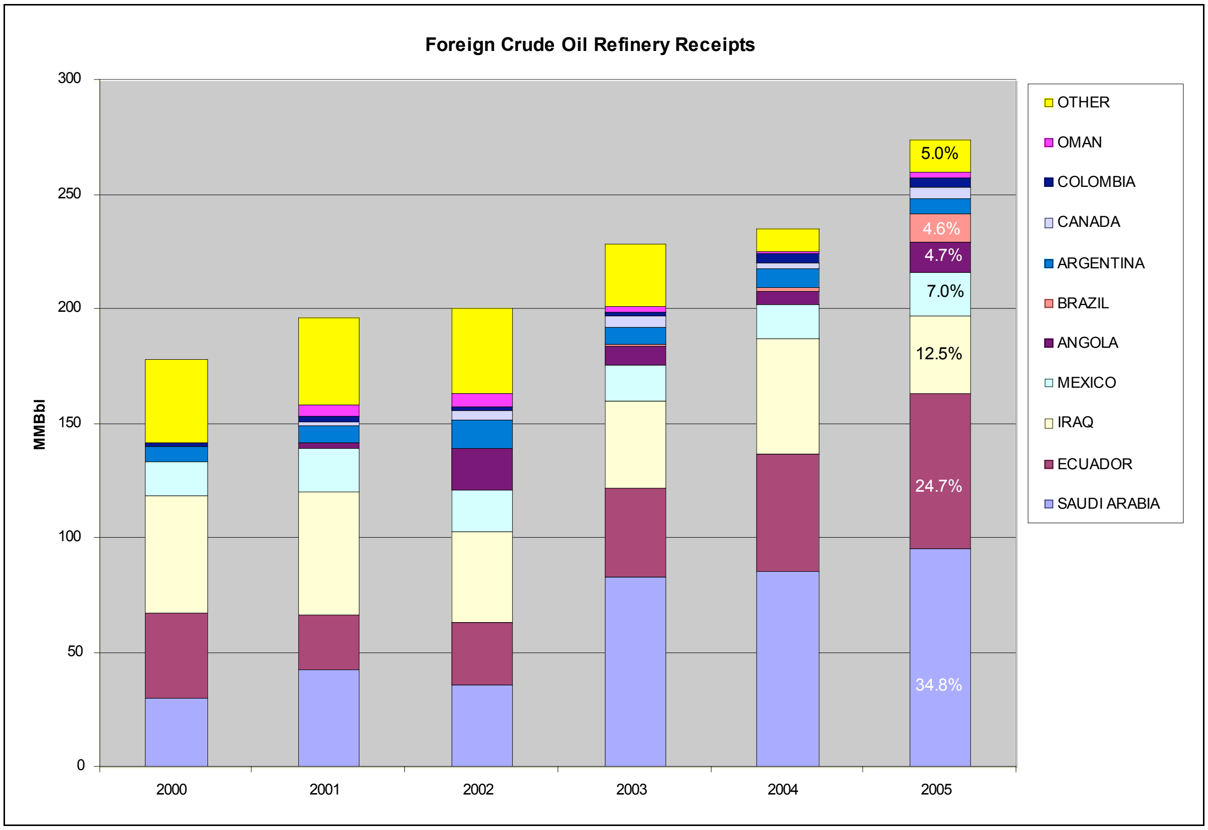
In 2005, California imported 21 percent of its total crude oil supply from Alaska. Oil fields in Alaska's North Slope produce a wide range of crude oils. API gravities from different fields range from 22 to 40 degrees. Alaskan refineries located along the Trans Alaska Pipeline System (TAPS) "top" the crude oil to produce light petroleum products and return residual products to the line. The resulting blended crude oil stream is referred to as Alaska North Slope oil (ANS). The ANS is an intermediate sour crude with an average API gravity of 29-29.5 degrees and sulfur content of 1.1 percent.

Like California crude oils, ANS production has been declining in the last 10 years. The average annual rate of decline in ANS production is approximately 5 percent per year.

Foreign Crude Oil Imports

The majority of crude oil imports to California are from the Middle East, Central America, and South America. Figure 4 shows a six year history of imports by region.

Figure 4



Source: Energy Information Administration

Crude oil imported from countries with volatile political and social structures leaves California vulnerable to changing world events. For example, attacks on Nigerian oil industry personnel led to the recent shutdown of nearly 9 percent of Nigeria's total oil production, which could impact global oil availability and increase feedstock costs for California refineries. Also, the growing political tension between the U.S. and Iranian governments over Iran's nuclear program could impact California's crude oil supply if the U.S. decides to impose sanctions on Iran.

Table 2 shows approximate crude oil characteristics for several imported crude oils.[14]

Table 2

Crude source	Paraffins Percent Volume)	Aromatics (Percent Volume)	Naphthenes (Percent Volume)	Sulfur (Percent Weight)	API gravity (Approx.)	Napht. yield (Percent Volume)	Octane No. (Typical)
Nigerian - Light	37	9	54	0.2	36	28	60
Saudi - Light	63	19	18	2	34	22	40
Saudi - Heavy	60	15	25	2.1	28	23	35
Venezuela - Light	35	12	53	2.3	30	2	60
Venezuela - Heavy	52	14	34	1.5	24	18	50
North Sea - Brent	50	16	34	0.4	37	31	50

Source: Office of Safety and Health Administration

The API gravity of refinery imports reported to the Energy Commission through the Petroleum Industry Information Reporting Act (PIIRA)[15] show an increase of 0.27 API per year from 1996 to 2005 for larger refineries. Smaller refineries show a relatively flat API during the same time period, predominantly because these smaller refineries solely use crude oil from California sources.[16]

Crude Oil Supply and Distribution to California Refineries

The distribution of domestic and imported crude oils is dependent on the port, pipeline, truck, and rail transport infrastructure within the state. All ANS and imported crude oils enter the state through ports in Los Angeles, Long Beach, and the Bay Area.

Water depth limits access to Bay Area ports. The water depth of these ports is typically between 32 to 45 feet, which is too shallow for large crude oil carriers. As an example, a carrier with a capacity of 1.3 million barrels will require a minimum water depth of at least 66 feet. For shallower ports, large vessels will anchor in a designated zone outside of the ports and smaller barges will transfer oil to the ports, a practice referred to as “lightering.” This practice adds to the delivery cost of crude oil to the refinery and increases the risk of accidental release of crude oil into the environment.

Another complication for the Bay Area ports is silting in the bays. Dredging of the bays is controversial in that habitat is disturbed and dredged material must be disposed of in an environmentally sound manner. For example, approximately 4 million cubic yards of sediment are dredged from the Central and South Bay per year.[17]

Pipeline networks tie the San Joaquin Valley crude oil production with refineries in both the Los Angeles and the Bay Area. Figure 5 shows the major crude oil pipelines in California.

Figure 5

Source: California Energy Commission

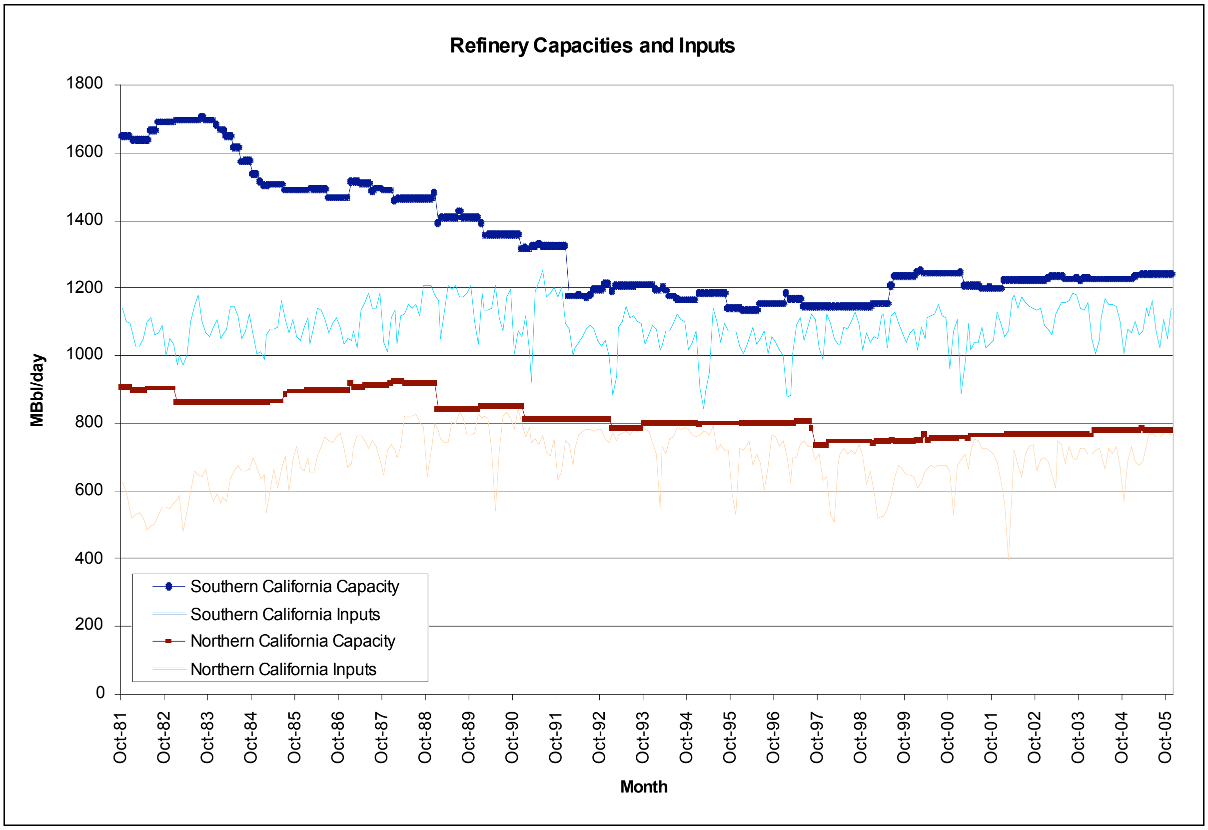
In California, 51 percent of the crude oil produced in the state is heavy crude. The transport of heavy crude through pipelines is complicated by the viscosity and inertia of the oil. Thus, some of the crude oil pipeline systems throughout the state require external heating. Booster stations are placed at intervals on the line where heating and/or pumping units facilitate the flow of the crude through the line. The proximity of booster stations is determined by the viscosity of the crude and by the average heat loss from the pipes from ambient weather conditions. Heavier crude oils are also blended with lighter crude oils to reduce viscosity, allowing transportation through pipelines without any heating.

Inland California crude oils are typically first piped to local refineries (Bakersfield and Santa Maria) because they are nearby and do not have port access. The balance of inland crude oils are piped to Northern and Southern California refineries.

Refinery Operations

In the last two decades, California refineries have been running increasingly closer to capacity levels. Figure 6 shows the total crude oil throughput refining capacity and the throughput oil inputs to the refinery by area.

Figure 6



Source: Petroleum Industry Information Reporting Act

The steady decline in refinery capacity during the 1980s and early 1990s is followed by a noticeable creep upward in the late 1990s and early 2000s. With refinery creep and greater import capabilities in the Los Angeles area, southern refineries are less constrained than their Bay Area and Central California counterparts. Southern California refineries also show an increasing level of crude oil imports.

Refinery operations must also consider recent diesel regulations by the U.S. Environmental Protection Agency (EPA) and the California Air Resources

Board (ARB). The EPA regulation lowers the allowable amount of sulfur in on-road diesel fuel from less than 500 parts per million (ppm) to less than 15 ppm. This requirement will take effect on June 1, 2006. The sulfur content and API gravity of crude oil input to the refinery in conjunction with the complexity of process units will affect the quantity of ultra-low sulfur diesel produced by the facility.

The hydrocracking and hydrotreater units remove sulfur within the refinery. Hydrocracking units break hydrocarbon molecules into lighter compounds in the presence of hydrogen. Hydrotreatment involves the chemical reaction of hydrocarbon compounds with hydrogen in the presence of a catalyst such as cobalt or alumina.[18]

Refineries throughout the U.S. are currently upgrading their desulfurization processes in order to meet the new diesel sulfur standards. This upgrade typically involves techniques such as changing the catalyst in the hydrotreater or installing booster pumps to force more feedstock through the unit. Both hydrocrackers and hydrotreaters also remove heavy metals and aromatics from the feedstock. This is particularly important in California where lower aromatic standards will be required along with the new ultra low sulfur diesel standards.

Findings

- The declining crude oil production in South-Central California has resulted in higher crude oil costs because of reliance on higher priced imported crude oils.

- Pipeline utilization rates are decreasing and the procurement of crude oil to inland refineries is becoming increasingly difficult as local supplies decline.

Current and Future Work

Additional reporting requirements in the Energy Commission’s new petroleum industry data collection regulations will greatly enhance the agency’s understanding of crude oil and finished product movements within the state. The addition of port, terminal, and pipeline information will provide the details needed to track infrastructure use within the state. This additional information will be essential in: assessing near-term petroleum infrastructure demand shifts, reviewing project expansion plans, and completing contingency studies.

Research and analysis should focus, in particular, on the following areas:

- Crude oil quality: The growing dependence of California refineries on imported crude oils requires a more detailed look at the characteristics of overseas crude oils entering ports in the state. The general trend of international crude oil production reflects an increase in low API, high sulfur content crude oil. However, overall API gravity in California refineries has increased primarily from the decline in heavy California crude oil production. The examination of supply information from secondary sources and from PIIRA reporting data will help to identify areas of constraint in the state.

- Total Acid Number (TAN): The increase in world production of heavy, sour, and high TAN crude oils will impact California refineries. An assessment of the crude oil processing capabilities of California refineries is needed to understand the potential implications of future changes in the global crude oil market.

- Crude oil pipelines: The decrease in crude oil production in the state has led to changes in the utilization rates of some crude oil pipelines. Modifying current pipeline systems and/or making new investments in distribution infrastructure may be necessary to provide more stable sources of crude oil for refineries without port access.

Endnotes

[1] California State Board of Equalization data for 2004. Taxable gasoline figures amounted to an average of 43.5 million gallons per day, while taxable diesel fuel sales figures have been adjusted upward to reflect an estimated 22 percent distribution of exempt and refund diesel sales that are excluded from their taxable gallons.

[2] Based on data compiled from the California Department of Conservation database production files, http://www.conservation.ca.gov/DOG/prod_injection_db/index.htm and MMS Offshore data, http://www.gomr.mms.gov/homepg/pubinfo/pacificfreeasci/product/pacificfreeprod.html.

[3] http://rru.worldbank.org/Documents/publicpolicyjournal/275-bacon-tordo.pdf.

[4] http://www.pacificenergypier400.info/pdfs/CRUDESUP/PACIFICP.PDF.

[5] http://www.ornl.gov/sci/fossil/Publications/RECENT%20PUBS/DDSum2003.pdf.

[6] Anne Shafizadeh, Gregg McAteer, and John Sigmon, *High-Acid Crudes*, paper presented at Crude Oil Quality Group meeting, New Orleans, January 30, 2003, [http://www.coqg.org/20030130special.asp]

[7] ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2004/PR06_Annual_2004.pdf.

[8] California Department of Conservation database production files, http://www.conservation.ca.gov/DOG/prod_injection_db/index.htm.

[9] Van Vector, Samuel, *Pricing Royalty Crude Oil*, http://www.econ.com/apijan00.pdf.

[10] MMS data for 2004 is approximately 95 percent complete. December 2005 data not yet posted.

[11] Jokuty, P.; Whiticar, S.; Wang, Z.; Fieldhouse, B.; and Fingas, M.; *A Catalogue of Crude Oil and Oil Product Properties for the Pacific Region,* 264p 1999.

[12] http://www.econ.com/apijan00.pdf.

[13] http://www.energy.ca.gov/2005_energypolicy/documents/2005-0516_workshop/presentations/Baker%20&%20OBrien%20Presentation%205-16-05.pdf.

[14] OSHA Technical Manual – Section IV: Chapter 2, http://www.osha-slc.gov/dts/osta/otm/otm_iv/otm_iv_2.html.

[15] PIIRA: the Petroleum Industry Information Reporting Act, Public Resources Code 25350 et seq.

[16] Large and small refineries are defined here as refineries with crude oil receipts in 2005 greater than or less than 5 percent of the total for the state, respectively.

[17] http://www.spn.usace.army.mil/ltms/chapter2.pdf.

[18] http://www.bp.com/genericarticle.do?categoryId=2013107&contentId=2019673.

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Appendix D

Tesoro Corrosion Monitoring Program

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Appendix D: Brief Description of the Tesoro Corrosion Monitoring Program

The Los Angeles Refinery has an Inspection Manual that describes the minimum technical and administrative requirements for the inspection of all refinery equipment. It defines the authority and responsibility of individuals, and provides the system by which activities are conducted in accordance with regulations, codes and policies specified by the California Division of Occupational Safety and Health (Cal OSHA). Tesoro implements additional inspection programs, beyond regulatory requirements, to ensure the integrity of its refinery equipment. The Refinery's Inspection Supervisor is responsible for the administration and implementation of the Inspection Manual. To ensure the highest degree of reliability and integrity of refinery equipment, the Refinery uses a variety of inspection techniques and methods. These inspection practices meet or exceed applicable industry standards, such as the Recommended Practices of the American Petroleum Institute.

To ensure the continued integrity of equipment testing and inspection at its facilities, the Los Angeles Refinery follows company inspection standards which focus on the following core processes:

• Organizational Capability and Competency
• Inspection Documentation
• Inspection Planning and Execution
• Continuous Improvement
• Performance Management Assurance

Testing methods used for inspections include visual examination, non-destructive evaluation (e.g. ultrasonic thickness measurements), and performance evaluations (e.g. hydrostatic testing).

The inspection and testing program at the refinery is conducted on an established schedule. A database of required inspection dates is maintained. An inspection report is provided to Tesoro Refining leadership each month.

Managing inspection in crude distillation units includes focus on damage mechanisms such as Sulfidation, Wet H2S Damage, and Naphthenic Acid Corrosion. The Corrosion Engineer or knowledgeable person establishes predicted or historical damage mechanisms and predicted corrosion rate for each system or area of a process unit. These damage mechanisms are used by the Inspector to select the appropriate inspection method. Inspection plans are developed for all applicable damage mechanisms following company and industry standards for refinery inspection. Methods of establishing piping inspection criteria are described in industry and company standards in which the frequency and extent of inspections are based on a consequence of failure classification and established or predicted corrosion rates (likelihood of failure). The following industry standards are used to establish the inspection program:

- API 510 Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration
- API 570, Piping Inspection Code
- API 574 Recommended Practice, Inspection Practices for Piping Systems Components
- API RP 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
- API RP 580 Risk-Based Inspection API Publication
- 581, Risk-Based Inspection Resource Document
- API RP 939-C, Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries

- NBI NB-23 National Board Inspection Code (NBIC)

In addition, implementation and monitoring of Integrity Operating Windows (IOW) is in progress and control of crude changes follows a rigorous management of change (MOC) process that has been a common practice for many years. Positive Material Identification and Low Silicon carbon steel surveys have been completed on the crude distillation units for piping in high temperature sulfidation service.

In addition to equipment integrity management programs, Tesoro employs operating practices to monitor and mitigate corrosion in these systems. These practices include obtaining routine laboratory analysis of hydrocarbon and water samples from the crude and vacuum units to monitor corrosive species or corrosion products and working with chemical vendors to provide corrosion inhibitors, passivators or chemical additives to reduce corrosion and fouling in the towers and associated feed and product piping and equipment. Operating envelopes or restrictions and alarms are used, for example on stream acid and sulfur content, to keep operations within boundaries and assure long term equipment reliability.