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TESORO
LOS ANGELES REFINERY

INTEGRATION AND COMPLIANCE PROJECT

FINAL
ENVIRONMENTAL IMPACT REPORT

VOLUME VII: Appendix G (G1-81 Attachment 24 – Response G1-97.3)

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The Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue, SE
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Safety Alert -- January 2, 2014

Preliminary Guidance from OPERATION CLASSIFICATION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert to notify the general public, emergency responders and shippers and carriers that recent derailments and resulting fires indicate that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.

Based upon preliminary inspections conducted after recent rail derailments in North Dakota, Alabama and Lac-Megantic, Quebec involving Bakken crude oil, PHMSA is reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. This advisory is a follow-up to the PHMSA and Federal Railroad Administration (FRA) joint safety advisory published November 20, 2013 [78 FR 69745]. As stated in the November Safety Advisory, it is imperative that offerors properly classify and describe hazardous materials being offered for transportation. 49 CFR 173.22. As part of this process, offerors must ensure that all potential hazards of the materials are properly characterized.

Proper characterization will identify properties that could affect the integrity of the packaging or present additional hazards, such as corrosivity, sulfur content, and dissolved gas content. These characteristics may also affect classification. PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, whether the shipment is in a cargo tank, rail tank car or other mode of transportation. Emergency responders should remember that light sweet crude oil, such as that coming from the Bakken region, is typically assigned a packing group I or II. The PGs mean that the material's flashpoint is below 73 degrees Fahrenheit and, for packing group I materials, the boiling point is below 95 degrees Fahrenheit. This means the materials pose significant fire risk if released from the package in an accident.

As part of ongoing investigative efforts, PHMSA and FRA initiated "Operation Classification," a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have been properly classified and describe the hazardous materials. Preliminary testing has focused on the classification and packing group assignments that have been selected and certified by offerors of crude oil. These tests measure some of the inherent chemical properties of the crude oil collected. Nonetheless, the agencies have found it necessary to expand the scope of their testing to measure other factors that would affect the proper characterization and classification of the materials. PHMSA expects to have final test

results in the near future for the gas content, corrosivity, toxicity, flammability and certain other characteristics of the Bakken crude oil, which should more clearly inform the proper characterization of the material.

"Operation Classification" will be an ongoing effort, and PHMSA will continue to collect samples and measure the characteristics of Bakken crude as well as oil from other locations. Based on initial field observations, PHMSA expanded the scope of lab testing to include other factors that affect proper characterization and classification such as Reid Vapor Pressure, corrosivity, hydrogen sulfide content and composition/concentration of the entrained gases in the material. The results of this expanded testing will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any unique hazards of the materials will enable offerors, carriers, first responders, as well as PHMSA and FRA to identify any appropriate mitigating measures that need to be taken to ensure the continued safe transportation of these materials.

PHMSA will share the results of these additional tests with interested parties as they become available. PHMSA also reminds offerors that the hazardous materials regulations require offerors of hazardous materials to properly classify and describe the hazardous materials being offered for transportation. 49 CFR 173.22. Accordingly, offerors should not delay completing their own tests while PHMSA collects additional information.

For additional information regarding this safety alert, please contact Rick Raksnis, PHMSA Field Services Division, (202) 366-4455 or E-mail: Richard.Raksnis@dot.gov. For general information and assistance regarding the safe transport of hazardous materials, contact PHMSA's Information Center at 1-800-467-4922 or phmsa.hm-infocenter@dot.gov.

HYDROCARBON PROCESSING

Innovative solutions for processing shale oils

07.01.2013 | **Sandu, C.**, Baker Hughes, Sugar Land, Texas; **Wright, B.**, Baker Hughes, Sugar Land, Texas

New monitoring protocols can provide advance warning of any negative aspects of shale oil processing, thus enabling the refiner to take corrective measures early.

Keywords: [shale oil] [paraffin] [waxes] [asphaltene]

The refining of shale oil (also known as tight oil) extracted through fracturing from fields such as Eagle Ford, Utica and Bakken has become prevalent in many areas of the US. Although these oils are appealing as refinery feedstocks due to their availability and low cost, processing can be more difficult.

The quality of the shale oils is highly variable. These oils can be high in solids with high melting point waxes. The light paraffinic nature of shale oils can lead to asphaltene destabilization when blended with heavier crudes. These compositional factors have resulted in cold preheat train fouling, desalter upsets, and fouling of hot preheat exchangers and furnaces. Problems in transportation and storage, finished-product quality, as well as refinery corrosion, have also been reported. Operational issues have led to cases of reduced throughput and crude unit shutdowns. The problems encountered with shale oil processing and possible prediction and control strategies will be presented.

NEW RESOURCES

The production of shale gas and oils has increased rapidly due to significant advancements in drilling technology and hydraulic fracturing. Coupling chemical treatments to the mechanical drilling capabilities has enabled increased production efficiency.

In September 2012, shale oil production was reported to be nearly 1 million bpd (1 MMbpd). The most prolific production locations are in North Dakota (Bakken), Texas (Eagle Ford), Ohio, Pennsylvania (Marcellus and Utica), Colorado, Kansas, Nebraska and Wyoming (Niobrara). Other locations identified for probable shale oil production are in New Mexico, Oklahoma and Utah. By 2020, production will be at least 10 MMbpd, based on expanded drilling activity, as shown in **Fig. 1.**[1] The predictions are largely dependent on the volatility of oil prices, technical advancements, capital expenditure, infrastructure needs, and challenges associated with the processing of these abundant resources.

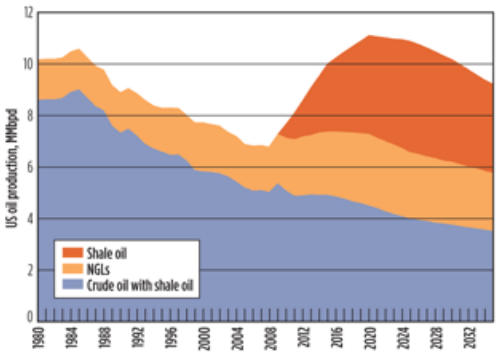

Fig. 1. Forecast prediction of US oil production. Source: EIA.

The properties of shale oils are significantly different than typical crude oils. As a result, a series of challenges needs to be solved to ensure uninterrupted transportation and refining of shale oils. The main challenges encountered with these feed streams will be discussed, including issues in storage, transportation, refining and finished fuel quality.

PHYSICAL AND CHEMICAL CHARACTERISTICS

Unlike most crude oils, shale oils are light, sweet oils, with a high paraffinic content and low acidity. They also have minimal asphaltenic content phase and varying contents of filterable solids, hydrogen sulfide (H_2S) and mercaptans. **Table 1** is a comparison of the oil characteristics typical for shale oil, and it includes data for Eagle Ford and Bakken shale oils.[2] There are significant differences in the sulfur content and the filterable solids loading. In addition, the streams from a shale oil production region can have significant variability, as shown in **Fig. 2.** These were shale oil samples from one field, with colors ranging from pale amber to black.

TABLE 1. Eagle Ford and Bakken shale oil property comparison

Parameter	Eagle Ford	Bakken
API	52	40.8
TAN, g KOH/g	< 0.05	0.09
Sulfur, wt%	< 0.2	0.304
Asphaltene, wt%	0.1	0.41
Resin, wt%	1.6	4.95
Filterable solids, PTB	225	76

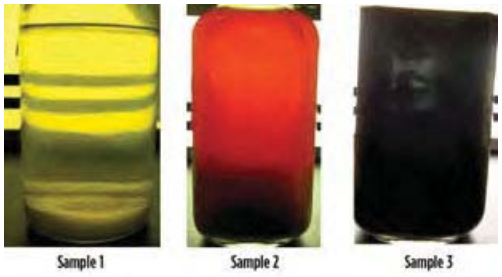

Fig. 2. Color variation of Eagle Ford shale oil.

Solids loading of samples from a single producing region can be highly variable and associated with the stage of fracturing and production from which the oil is produced. **Table 2** shows typical analytical results on the three shale oil samples from **Fig. 1.** Filterable solids ranged from 176 pounds per thousand barrels (PTB) to 295 PTB.

TABLE 2. Physical properties of Eagle Ford shale oil samples

Parameter	Yellow	Red	Black
API	55	44.6	52.3
TAN, g KOH/g	< 0.05	0.07	< 0.05
Sulfur, wt%	< 0.2	< 0.2	< 0.2
Na, ppm	1	1.6	1.6
K, ppm	0.3	0.4	0.5
Mg, ppm	3.4	2.9	3
Ca, ppm	2.6	2.8	3.8
Asphaltenes, wt%	0	0	0.1
Resin, wt%	0.5	3.2	1.6
Filterable solids, PTB	176	295	225

Paraffin. The paraffin content of shale oil is one of the main properties that contributes to downstream problems from transportation and storage to refinery processing. Analyses of one batch of shale oil revealed paraffin chains containing well over 50 carbons. Similar paraffin analyses have been observed from multiple shale oils. To understand fouling due to wax deposition, a carbon-chain profile analysis should be performed to document the molecular-weight distribution (MWD) and the melting points of the waxes in the system. **Fig. 3** illustrates the characterization of waxes from Eagle Ford and Bakken oil samples. Some samples of Eagle Ford shale oil contain over 70 carbon paraffins.

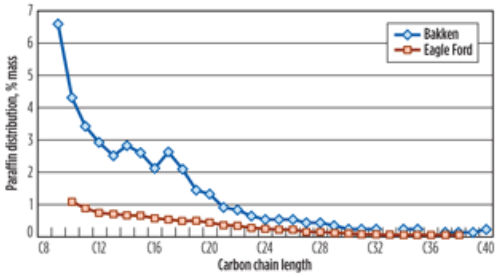

Fig. 3. Paraffin chain distribution for Bakken and Eagle Ford shale oils.

Due to their paraffinic nature, mixing shale oil with asphaltenic oil leads to destabilization of the asphaltene cores. Asphaltenes are polar compounds that influence emulsion stability. Once the asphaltenes destabilize, they can agglomerate, leading to larger macro-molecules. On hot surfaces, agglomerated asphaltenes easily crack or dehydrogenate and gradually form coke-like deposits.

Several shale oil production locations have high H_2S loading. To ensure worker safety, scavengers are often used to reduce H_2S concentrations. The scavengers are often amine-based products-—methyl triazine, for instance—that are converted into mono-ethanolamine (MEA) in the crude distillation unit (CDU). Unfortunately, these amines contribute to corrosion problems in the CDU. Once MEA forms, it rapidly reacts with chlorine to form chloride salts. These salts lose solubility in the hydrocarbon phase and become solids at the processing temperatures of the atmospheric CD towers and form deposits on the trays or overhead system. The deposits are hygroscopic, and, once water is absorbed, the deposits become very corrosive. These physical properties are responsible for the problems that are being experienced by refineries handling shale oils.

Extraction and production

The challenges associated with the production of shale oils are a function of their compositional complexities and the varied geological formations where they are found. These oils are light, but they are very waxy and reside in oil-wet formations. These properties create some of the main difficulties associated with shale oil extraction. Such problems include scale formation, salt deposition, paraffin wax deposits, destabilized asphaltenes, corrosion and bacteria growth. Multi-component chemical additives are added to the stimulation fluid to control these problems.

Shale oils are characterized by low-asphaltenic content, low-sulfur content and a significant MWD of the paraffinic wax content. Paraffin carbon chains of C10 to C60 have been found, with some shale oils containing carbon chains up to C72. To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously.

Scale deposits of calcite, carbonates and silicates must be controlled during production or plugging problems arise. A wide range of scale additives is available. These additives can be highly effective when selected appropriately. Depending on the nature of the well and the operational conditions, a specific chemistry is recommended or blends of products are used to address scale deposition.

Storage and transportation

Another challenge encountered with shale oil is the transportation infrastructure. Rapid distribution of shale oils to the refineries is necessary to maintain consistent plant throughput. Some pipelines are in use, and additional pipelines are being constructed to provide consistent supply. During the interim, barges and railcars are being used, along with a significant expansion in trucking to bring the various shale oils to the refineries. Eagle Ford production is estimated to increase by a factor of 6—from 350,000 bpd to nearly 2 MMbpd by 2017; more reliable infrastructures are needed to distribute this oil to multiple locations. Similar expansion is estimated for Bakken and other shale oil production fields.

The paraffin content of the shale oils is impacting all transportation systems. Wax deposits have been found to coat the walls of railroad tank cars, barges and trucks. Waxy deposits in pipelines regularly require pigging to maintain full throughput. Bakken shale oil is typically transported in railcar, although pipeline expansion projects are in progress to accommodate the long-term need. These railcars require regular steaming and cleaning for reuse. Similar deposits are being encountered in trucks being used for shale oil transportation. The wax deposits also create problems in transferring the shale oils to refinery tankage. **Fig. 4** shows samples of deposited wax collected

from pigged pipelines in shale oil service.

Fig. 4. Waxy deposits removed from shale oil pipelines.

Multiple chemical and mechanical solutions are used to mitigate these deposit problems. A combination of chemical-additive treatment solutions involving paraffin dispersants and flow drag-reducer technologies has proven to be effective in pipeline applications. Wax dispersants and wash solvents have been used to clean transportation tanks and refinery storage vessels. In the case of pipeline fouling management, a combination of these technologies, coupled with frequent pigging, are the main means to mitigate wax deposition. Preventive fouling control programs have been developed to manage the wax deposition occurring in storage tanks. By injecting the proper chemical treatment to control wax buildup in storage tanks, the production field and refinery can handle and transfer larger quantities of oil without significant plugging issues.

One other problem encountered in storing and transporting shale oils is the concentrations of light ends that accumulate in the vapor spaces, requiring increased safety and relief systems. Shipping Bakken crude via barges was challenged by the increased levels of volatile organic compounds (VOCs). Vapor-control systems should be used to ensure a safe environment.

Due to the paraffinic nature of shale oils and their lack of heavy bottoms, most refineries mix crude oil with the shale oil. Unfortunately, the shale oils have low aromatic content, so mixing with conventional crude oil often leads to asphaltene destabilization. If blended oils are transported, the deposits can consist of waxes and precipitated asphaltenes. Dispersants specifically designed for both hydrocarbon types can control deposit formation during transportation. Until a proper transportation infrastructure is built, significant variation of shale oil shipments and potential for contamination are still possible. Refineries are already experiencing the impact of the quality variation of shale oil feeds, and of processing challenges.

REFINERY IMPACTS

Due to the variation in solids loading and their paraffinic nature, processing shale oils in refinery operations offers several challenges. Problems can be found from the tank farm to the desalter, preheat exchangers and furnace, and increased corrosion in the CDU. In the refinery tank farm, entrained solids can agglomerate and rapidly settle, adding to the sludge layer in the tank bottoms. Waxes crystalize and settle or coat the tank walls, thus reducing storage capacity. Waxes will stabilize emulsions and suspend solids in the storage tanks, leading to slugs of sludge entering the CDU. Waxes will also coat the transfer piping, resulting in increased pressure drop and hydraulic restrictions.

Mixing asphaltenic crude with paraffinic shale oils leads to asphaltene destabilization that contributes to stable emulsions and sludge formation. To control these problems, wax-crystal modifiers or paraffin dispersants can be applied successfully. Wax-crystal modifiers must be added when the shale oil is still hot from the formation. When

the paraffins begin to leave the liquid phase, wax modifiers are ineffective, and paraffin dispersants are required to control deposition.

Desalter operations may suffer from issues related to the shale oil properties. Solids loading can be highly variable, leading to large shifts in solids removal performance. Sludge layers from the tank farm may cause severe upsets, including growth of stable emulsion bands and intermittent increases of oil in the brine water. Agglomerated asphaltenes can enter from storage tanks or can flocculate in the desalter rag layer, leading to oil slugs in the effluent brine.

Solutions include using tank farm additives to control the formation of sludge layers, along with specially designed asphaltene dispersants and aggressive desalter treatments to ensure optimum operation. Pretreatment, coupled with high-performance desalter programs, have provided the best overall desalter performance and desalted crude quality; multiple treatment options for both areas can ensure maximum performance. **Fig. 5** is an example of applying a tank pretreatment. A crude-oil tank treatment program was initiated that broke waxy emulsions in tankage, enabling improved water resolution of the raw crude oil and minimizing sludge and solids entering the desalter. This program provided significant improvement of solids released into the desalter brine water compared to previous operations. Prior to initiating the pretreatment program, solids in the brine averaged 29 PTB, and the emulsion band control was sporadic. After the tank pretreatment program started, the desalter emulsion band could be controlled with the emulsion breaker program, and solids removal to the brine water increased by a factor of 8 to an average of 218 PTB.

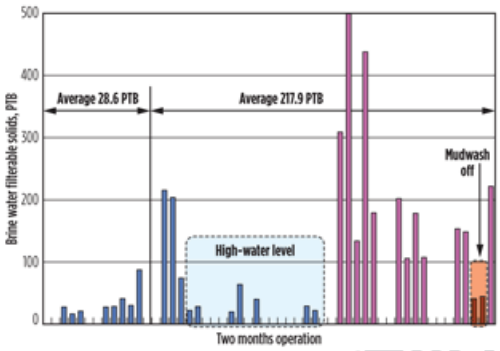

Fig. 5. Tank pretreatment impact on desalter filterable solids.

Preheat exchanger fouling has been observed in the cold train before the desalters and in the hot train after the desalters. Cold train fouling results from the deposition of insoluble paraffinic hydrocarbons, coupled with agglomerated inorganic solids. Solutions to cold train exchanger fouling include the addition of wax dispersants and other oil management best practices to ensure consistent solids loading with minimum sludge processing.[a] Crude oil management can include additives to stabilize asphaltenes and surfactants that resolve emulsions and improve water separation.[a] These practices also include proactive asphaltene stability testing to ensure that the crude blends to be processed retain an acceptable compatibility level.

Hot train fouling occurs from destabilized asphaltenes that agglomerate and form deposits. These materials entrain inorganics, such as iron sulfide and sediments from production formations, into the deposit matrix. Some deposits, including high molecular-weight paraffins, become complex with the asphaltene aggregates. Mixing shale oils with asphaltenic crude oils results in rapid asphaltene agglomeration. Rapid hot train exchanger fouling has been seen

in units running crude blends with asphaltene concentrations of 1% or less. **Table 3** shows the analysis from a hot exchanger deposit that had to be shut down for cleaning after only a short time online. This hydrogen-to-carbon ratio is consistent with asphaltenic deposits.

TABLE 3. Hot train exchanger deposit analyses of shale oil with asphaltenic crudes in wt%

Sample	C	H	N	O	Cl	Fe	S	H/C atomic ratio	Ash	Summary
Exchanger 1-crude side	82	8	1	2	1		6	1.16	1	Asphaltenes
Exchanger 2-crude side	78	7	1	4	1	1	8	1.07	3	Asphaltenes
Exchanger 3-crude side	81	8	1	2	1		7	1.18	3	Asphaltenes

Feed analyses of the shale oil and crude blend being processed revealed poor stability of the asphaltenes.

Asphaltene stability tests are used to measure the ability of a crude oil blend to hold asphaltenes in solution.[3, a] The method utilizes light scattering, coupled with automatic titration, to force asphaltene destabilization and agglomeration.

As titration begins, the oil becomes less opaque and the light intensity increases. When the destabilization point is reached and the asphaltenes rapidly agglomerate and flocculate, the fluid opacity suddenly increases. Inflection points on the curve show where asphaltenes become unstable: farther to the right indicates higher stability asphaltenes, while inflection points farther to the left suggest unstable asphaltenes. **Fig. 6** shows asphaltene stability results for several crude blends, along with a test on Eagle Ford shale oil. An inflection point was not achieved for the shale oil because it has no asphaltenes to flocculate. Typical crude oils are shown, with asphaltene stability index (ASI) results around 120. When the shale oil was blended with the typical crude oils at a ratio of 80/20, the measured asphaltene stability result was less than 30, indicating rapid and uncontrollable destabilization of the asphaltenes.

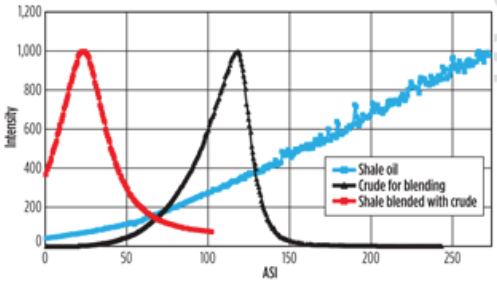

Fig. 6. Asphaltene stability index testing of shale oil and shale oil/crude blends.

If the asphaltenes in the crude blend were not being rapidly destabilized, the asphaltene stability would have been well above 120. This data shows that mixing certain crude oils with shale oil can result in rapid asphaltene

deposition. New technology can provide the capability to rapidly perform asphaltene stability measurements onsite with a high degree of accuracy.[4, a]

Hot-train exchanger fouling can be controlled through antifoulant additives designed to control the agglomeration and deposition of asphaltenes and entrained inorganic solids. Another fouling control strategy is to do regular analysis of the stability of the asphaltenes in the crude oil blend under consideration for processing. This information can guide operations to minimize fouling problems.

CDU atmospheric furnace fouling has also been observed at several refineries processing shale oils, especially those processing a blend of asphaltenic crude and shale oils. In some cases, the fouling rate was so severe that the crude unit had to be shut down for furnace pigging. CDU furnace operations with conventional crude oils experience little to no fouling, and these furnaces can easily run for 5 to 6 years between turnarounds. **Fig. 7** shows the rate of fouling in a unit processing a mixture of shale oil with crude vs. the rate of fouling with more typical crude feeds.

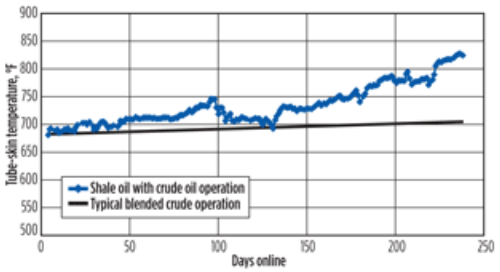

Fig. 7. Atmospheric furnace skin temperature trends.

Depending on the asphaltene stability of the shale oil/crude oil blend, the furnace skin temperatures can climb by 0.5°F/day to 2°F/day vs. more typical operations of 0.1°F or less. To control furnace fouling when processing shale oils blended with various crude oils, constant monitoring of the asphaltene destabilization potential is required. Setting a minimum limit on the ASI ensures that the majority of the asphaltenes stay in solution. This limit should be developed for each unit, based on correlations between the rate of furnace fouling being experienced and the stability index. Using appropriate antifoulant additives can control agglomeration of asphaltenes and disperse offending materials into the bulk oil phase.

Shale oils often contain high concentrations of H_2S that require treatment with scavengers due to safety purposes. Amine-based scavengers often decompose as the crude oil is preheated through the hot preheat train and furnace, forming amine fragments. MEA, one of the most commonly used amines, readily forms an amine-chloride salt in the atmospheric tower. These salts deposit in the upper sections. Often, under-deposit corrosion is the major cause of failures in process systems because CDU tower under-salt corrosion rates can be 10 to 100 times faster than a general acidic attack. Mitigation strategies include controlling chloride to minimize the chloride traffic in the tower top and overhead, increasing the overhead operating temperature so that the salts move further downstream in the overhead system, and acidifying the desalter brine water to increase removal of amines into the water phase.

Finished fuels

The quality of the finished fuels from refining shale oils has changed significantly. As the shale oils have higher light-ends content, one benefit is increased production of naphtha for gasoline, and stable diesel and jet distillates. These increased volumes can boost refinery margins. However, due to the chemical nature of these shale oil feeds,

several challenges can be encountered. The streams are more paraffinic—thus, they suffer from poor pour and cloud-point properties. In addition, shale oils are lower in sulfur content, so the need for lubricity additives is anticipated. Effective additives can be used to improve all distillate stream properties. Conductivity can also be off-spec; a combination of lubricity/conductivity improvers can raise the quality of the distillate. To optimize chemical treatment program, testing on specific product streams is required and suitable product selection should be customized. **Table 4** summarizes the main issues identified for different distillate cuts that a refiner can experience as well as chemical and mechanical solutions that can mitigate these challenges.

TABLE 4. Possible problems and solutions for finished fuels from shale-oil processing

Distillate	Challenge	Solutions
Light ends (C_1–C_4)	Copper strip corrosion	Corrosion inhibitors
Naphtha	Water shedding, corrosion	Corrosion inhibitors, microbial control
Jet fuel	Lubricity, conductivity, water shedding, stability	Various lubricity additives, filtration devices, dry solid systems, microbial control
Diesel	Lubricity, conductivity, stability, water shedding	Various lubricity additives, de-hazers, microbial control
Residual fuel oil	Asphaltene instability, gum deposits	Blending and compatibility monitoring Asphaltene stabilizers Paraffin dispersants

Preparing to process shale oils. The risks that shale oils present can be successfully managed. The first step is to identify the onset of all concerns. To be prepared for processing shale oils, monitoring protocols can provide advance warning of any negative aspects of shale oil processing and the impacts on product quality, thus enabling the refiner to take corrective measures early. **HP**

ACKNOWLEDGMENT

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NOTES

[a] CRUDE OIL MANAGEMENT, ASIT and FIELD ASIT SERVICES are trademarks of Baker Hughes Incorporated.

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[4] Sandu, C. and T. Falkler, "New Field Tool Helps Refiners Detect Incompatible Feedstocks, Prevent Operational Problems," ERTC 2012.

The authors

Bruce Wright, a Baker Hughes senior technical support engineer for downstream chemicals, is based in Sugar Land, Texas, and specializes in the hydrocarbon processing industries. With more than 30 years of industry experience, he is involved in technical support and troubleshooting of refinery fouling problems. Mr. Wright has experience as a product development research scientist and also in environmental, health and safety compliance. He is an inventor or co-inventor on eight US patents and has published nine technical papers. Mr. Wright is a 1977 graduate of the Rensselaer Polytechnic Institute with a BS degree in chemical engineering. He also holds an MBA degree from the University of Houston. Mr. Wright is a registered professional engineer in the state of Texas, and is a member of the American Institute of Chemical Engineers.

Dr. Corina Sandu, a Baker Hughes R&D manager for downstream chemicals, is responsible for leading a team of scientists who are researching and developing upgraded and novel technologies to increase refinery industry processing performance. She is located in Sugar Land, Texas. Dr. Sandu holds a PhD in materials chemistry from the University of Houston, and a post-doctorate from Rice University. She is a member of the American Chemical Society and the Society of Petroleum Engineers. Dr. Sandu has authored and co-authored 24 publications in peer-reviewed journals and holds five patents.

Charles Harry *07.19.2013*	The addition of mbp needs or usage would be useful relative to Fig.1 in regards to why there is an ongoing large increase in shale oil production followed by it gradual decline.
Peter LoGiudice *07.10.2013*	Excellent well thoughtout overview-Thanks
Joseph *07.03.2013*	What will be the typical Calorific Value of Shale oil in Kcal/ Kg? C/H2 Ratio Any estimation of Metal Contents like Vanadium, Na, Si etc

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The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert to notify the general public, emergency responders and shippers and carriers that recent derailments and resulting fires indicate that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.

Based upon preliminary inspections conducted after recent rail derailments in North Dakota, Alabama and Lac-Megantic, Quebec involving Bakken crude oil, PHMSA is reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. This advisory is a follow-up to the PHMSA and Federal Railroad Administration (FRA) joint safety advisory published November 20, 2013 [78 FR 69745]. As stated in the November Safety Advisory, it is imperative that offerors properly classify and describe hazardous materials being offered for transportation. 49 CFR 173.22. As part of this process, offerors must ensure that all potential hazards of the materials are properly characterized.

Proper characterization will identify properties that could affect the integrity of the packaging or present additional hazards, such as corrosivity, sulfur content, and dissolved gas content. These characteristics may also affect classification. PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, whether the shipment is in a cargo tank, rail tank car or other mode of transportation. Emergency responders should remember that light sweet crude oil, such as that coming from the Bakken region, is typically assigned a packing group I or II. The PGs mean that the material's flashpoint is below 73 degrees Fahrenheit and, for packing group I materials, the boiling point is below 95 degrees Fahrenheit. This means the materials pose significant fire risk if released from the package in an accident.

As part of ongoing investigative efforts, PHMSA and FRA initiated "Operation Classification," a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have been properly classified and describe the hazardous materials. Preliminary testing has focused on the classification and packing group assignments that have been selected and certified by offerors of crude oil. These tests measure some of the inherent chemical properties of the crude oil collected. Nonetheless, the agencies have found it necessary to expand the scope of their testing to measure other factors that would affect the proper characterization and classification of the materials. PHMSA expects to have final test

results in the near future for the gas content, corrosivity, toxicity, flammability and certain other characteristics of the Bakken crude oil, which should more clearly inform the proper characterization of the material.

"Operation Classification" will be an ongoing effort, and PHMSA will continue to collect samples and measure the characteristics of Bakken crude as well as oil from other locations. Based on initial field observations, PHMSA expanded the scope of lab testing to include other factors that affect proper characterization and classification such as Reid Vapor Pressure, corrosivity, hydrogen sulfide content and composition/concentration of the entrained gases in the material. The results of this expanded testing will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any unique hazards of the materials will enable offerors, carriers, first responders, as well as PHMSA and FRA to identify any appropriate mitigating measures that need to be taken to ensure the continued safe transportation of these materials.

PHMSA will share the results of these additional tests with interested parties as they become available. PHMSA also reminds offerors that the hazardous materials regulations require offerors of hazardous materials to properly classify and describe the hazardous materials being offered for transportation. 49 CFR 173.22. Accordingly, offerors should not delay completing their own tests while PHMSA collects additional information.

For additional information regarding this safety alert, please contact Rick Raksnis, PHMSA Field Services Division, (202) 366-4455 or E-mail: Richard.Raksnis@dot.gov. For general information and assistance regarding the safe transport of hazardous materials, contact PHMSA's Information Center at 1-800-467-4922 or phmsa.hm-infocenter@dot.gov.

New Spilled Crude Oil Discovered At Mosier Train Crash . News

A 16-car oil train derailment caused a fire and left a small oil sheen on the Columbia River.

Conrad Wilson/OPB

The black Union Pacific oil cars that derailed Friday in the Columbia River Gorge are lined up next to the tracks that cut through Mosier, like oversized, crumpled beer cans discarded with little regard.

Crews spent Monday continuing their cleanup efforts, pumping crude oil out of the derailed cars into tanker trucks that drove the oil away from the scene. Around mid-morning, officials turned their efforts to newly discovered oil in a pipe leading from Mosier's water treatment plant to the Columbia River.

"The main sewer line that leads to the wastewater treatment plant was damaged during the derailment," said David Byers, the Washington state Department of Ecology response manager.

So far, cleanup crews have cleaned about 10,000 gallons of crude oil out of the town's sewage system. Another 32,000 gallons burned off or vaporized in the initial crash, was captured by booms in the Columbia, or soaked into the soil.

RELATED COVERAGE

5 Things You Need To Know About The Oil Train Derailment Along The Columbia River

A boil water ban was lifted Monday after tests confirmed the city's water was safe to drink. Still, residents are being asked to limit toilet flushing and long showers — even as temperatures exceeded 90 degrees for the third straight day — because the water treatment plant is offline and all sewage is being sent by truck to Hood River for treatment.

On Sunday, for the first time since the derailment, Union Pacific started running trains along the Oregon side of the Columbia River Gorge and through Mosier.

At a community meeting Sunday, the City Council passed a resolution that asked the railroad to wait until all the crude oil was removed from

the derailed cars before sending more trains because of concerns about safety.

In some places in Mosier the trains pass slowly within just a few feet of the derailed tankers.

“The tracks are no safer today then the day that this derailment happened and now we have large tankers of fuel sitting between the track and our town,” said Emily Reed, the council president for the city of Mosier.

Union Pacific said they’ve been working with the city, but the railroad also has obligations to other clients that it must meet.

“We have a lot of companies that are depending on Union Pacific to get their products,” said Espinoza. “We have done our best to reroute what we can, but unfortunately there is just a lot of people that are waiting for their goods.”

So far, at least 10 trains have passed through Mosier since resuming after the derailment. No crude oil trains are scheduled to pass through for the next week, but Espinoza said that’s more a function of scheduling than any deliberate action taken by the railroad to avoid sending crude through Mosier. She said the railroad plans to resume normal operations soon.

“I understand how they feel and I just want them to know that we’re doing everything that we can to correct the situation and to make sure that we operate in the safest manor,” she said.

In a joint statement Monday, Oregon Gov. Kate Brown along with Sens. Jeff Merkley and Ron Wyden, as well as Reps. Earl Blumenauer and Suzanne Bonamici called for a temporary halt to oil train service through the Gorge.

RELATED COVERAGE

Mosier Fire Chief Calls Shipping Bakken Crude Oil By Rail 'Insane'

“Oil train tankers are still lying on their sides in Mosier, the ground and water have yet to be cleaned up, and there’s still no good explanation for the cause of Friday’s crash,” the statement said. “It is too soon to resume oil train traffic through the Columbia River Gorge.”

The elected leaders called on Union Pacific to hold off on sending oil trains through the Gorge until they can give Mosier residents a concrete explanation of what caused the accident and “assurance that the company is taking the necessary steps to prevent another one.”

Wyden said he’s been in contact several times with the head of Union Pacific and thinks the railroad will comply.“I think if they were to just stiff the Pacific Northwest and just say, ‘To heck with the fact that all these legislators and our governor are calling for this timeout in order to ensure there’s basic safety,’ I think it would be a big mistake for them with respect to their congressional relations,” he said.
Still, some who live in the gorge are less convinced any assurances can make oil trains safe.

Hood River Mayor Paul Blackburn said it’s not lost on him that the oil train derailment could’ve been in his community.

“These rail lines move right through our little towns,” Blackburn said. “With the exponential growth of oil trains coming through these little towns is this really a very good idea?”

Special Report: Refiners processing heavy crudes can experience crude distillation problems

11/18/2002

Refiners will process increasingly heavier crude slates during the next 10 years. A majority will originate from the Orinoco oil belt bitumen upgraders in Venezuela and the Athabasca tar sands region of northern Alberta.

Even blended with lighter crudes, these lower-gravity blends will require crude-unit process flow scheme and equipment design changes to meet profitability objectives.

This article addresses crude distillation unit (CDU) problem areas and identifies specific sections requiring investment to maintain profitability throughout a 4-5 year run length for refiners processing heavy crudes.

Some heavy crudes are blends of 6-8° API bitumens combined with hydrotreated lighter products from bitumen upgraders.

The blended lighter products that help produce synthetic crudes generally distill in the atmospheric column leaving a very heavy 6-8° API feed to the vacuum unit. CDUs must operate at increased severity to maintain product cut points and qualities.

Heavy crudes are more difficult for the CDU to process. Historically, refiners processing heavier crudes have had problems maintaining:

- Crude charge rate.
- Product yield and quality.
- Unit reliability.

CDU processing difficulties

Table 1 shows some specific problems refiners face when processing heavy crude blends.

COMMON PROCESSING PROBLEMS Table 1

High crude-side pressure drop
Desalter upsets and poor desalting
Rapid crude-column condenser corrosion
Crude column naphtha-jet fuel section fouling
Low diesel product yield
Vacuum heater coking
Vacuum column coking
Vacuum column fouling (top section)
High vacuum-column operating pressure
Low HUGO product draw temperature
Low HUGO product yield
High metals feed to the cat feed hydrotreater
General corrosion problems

Click here to enlarge image

Heavy crudes have higher viscosities, some have higher salt content, several have high naphthenic acid content, and they are all more difficult to distill than lighter crude blends. Some upgrader crudes also have lower thermal stability than conventional crudes and higher fouling tendencies due to the increased likelihood of asphaltene precipitation.

Processing difficulties can result from flow schemes and equipment designs that may have worked well with light crudes, but are not compatible with the heavy crude characteristics. Revamps to process heavy crudes must carefully consider the flow scheme and equipment design in order to maintain crude charge rate, product yield and quality, and unit reliability.

Crude blends with gravities <22° API require sufficient cold exchanger train preheat to achieve efficient desalting, which typically requires a desalter temperature between 270° and 300° F.

The desalter must separate the emulsion into low-salt crude and oil-free water.

With a heavier crude feed, the desalter temperature can decrease by 30° to 40° F., if no additional surface area is added to the cold exchanger train. The desalted crude's salt content can increase dramatically if the temperature is too low. Many heavy crudes such as Zuata or Merey can have high salt contents depending on production field operations; therefore, good desalter performance is critical. Poor cold exchanger train designs often cause low desalter

temperatures, poor salt removal, and periodic upsets that send large quantities of brine to the atmospheric heater and column.

High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability.

Most heavy crudes have higher viscosities, a condition that makes increasing or maintaining crude charge rate a challenge.

Higher viscosity reduces the crude charge-pump developed head, increases exchanger network pressure drop, and lowers heat-transfer coefficients throughout the cold preheat train. Crude charge rate, atmospheric column heat removal, and desalter temperature are all adversely affected.

Many heavy crudes contain more vacuum gas oils. Refiners, therefore, often increase the atmospheric tower bottom (ATB) product cut point to stay within the vacuum column diameter limits. As ATB cut point increases, however, vacuum unit feed gets heavier resulting in higher vacuum tower bottoms (VTB) yield.

Increasing the vacuum heater outlet temperature can sometimes offset a higher ATB cut point. But many refiners have existing heater design problems that prevent a higher outlet temperature without shortening heater run length. Refiners, therefore, must optimize ATB product cut point to maximize heavy vacuum gas oil (HVGO).

An optimized ATB cut point is about 700° F. for heavy Venezuelan Merey, BCF-17, and Zuata crudes, assuming no downstream equipment limits.

Most refiners and designers adjust ATB cut point vs. crude heater outlet temperature only.

Other parameters are, however, more effective in adjusting ATB cut point: minimized atmospheric column flash-zone pressure, minimized percent overflash, and optimized ATB stripping efficiency.

This maximizes diesel recovery and reduces vacuum ejector condensable load, which permits lower vacuum column operating pressure and helps maintain HVGO product cut point.

Maintaining HVGO cut point is a significant challenge with heavier crude blends. Most refiners lose 40° F. or more in HVGO product cut point when switching to a heavy crude diet. Maintaining cut point requires a combination of lower operating pressure, higher heater outlet temperature, reduced flash-zone pressure, lower flash-zone oil partial pressure (more heater coil steam), and improved VTB stripping. The right combination will be specific to each unit.

The combination of operating variables needed to maintain or increase HVGO cut point is more severe and can lead to rapid vacuum heater or column coking if the equipment is not carefully designed.

Heavy crudes have much higher microcarbon residue (MCR), asphaltenes, and metals. As mandated refinery gasoline and diesel pool sulfur specifications take effect, minimizing cat feed hydrotreater (CFHT) feed contaminants becomes more important.

In some cases, vanadium in the CFHT feed has increased from less than 1 ppm to 5-10 ppm with heavy Venezuelan crudes.[1]

High feed-stream contaminants can reduce run length to less than half the planned turnaround interval.

Optimizing the atmospheric column flash-zone and wash section, and the vacuum unit design can reduce CFHT feed vanadium by 30-40%.

Heavy crude properties

True boiling point (TBP) distillation curve, contaminants (MCR, asphaltenes, and metals) distribution, viscosity, salt content, and total acid number (TAN) increase CDU operating severity and make heavy crudes inherently more difficult to process.

Venezuelan heavy crudes include Merey, BCF-17, Zuata, BCF-22, and Laguna Blend 22. US refiners are also processing large volumes of Mexican Maya crude. Heavy Canadian crudes include Cold Lake blend, Lloydminster (LLB), and tar sands blends.

Only a few refiners can process these crudes neat.

Other refiners that increase their heavy crude percentage also face many of the same processing challenges.

TBP distillation

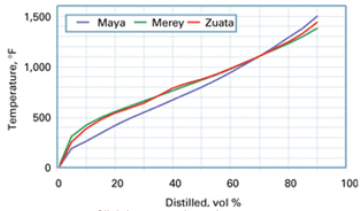
Accurate crude TBP curves are essential when CDUs are revamped to process heavy crude feeds. Figs. 1 and 2 show TBP curves for selected heavy Venezuelan and Canadian crudes.

TBP curves are typically generated from ASTM D2892 and D5236 tests. Some refiners now use high-temperature simulated distillation (HTSD) to characterize the whole crude. Significant differences between the two methods become more pronounced as crude API gravity decreases.[2]

We found that HTSD curves provide the best characterization of product yields in the 650+° F. portion of the distillation curve.

We reviewed several comprehensive test runs on crude units processing heavy crudes and compared synthesized whole crude TBP curves generated from product stream HTSDs, whole crude HTSDs, and crude assay TBP curves generated from ASTM

LATIN AMERICA HEAVY CRUDES Fig. 1



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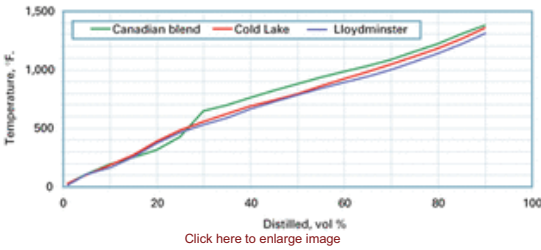
CANADIAN HEAVY CRUDES Fig. 2



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D2892 and D5236 tests.

During a CDU revamp to process heavy crude, the designer must accurately characterize crude feed; otherwise, predicted product yields, operating conditions, and equipment design may be flawed.

Inaccurate feed characterization of crude's heavy end has resulted in poor revamp yields and coked vacuum column wash beds.

Whole crude properties

Table 2 shows vanadium, viscosity, and salt content for some heavy crudes. Fig. 3 shows the vanadium distribution curve for Maya crude.

Some vanadium compounds begin to vaporize at 925-950° F. TBP temperatures; therefore, HVGO vanadium will rise as cut point increases.[3]

Improved HVGO fractionation lowers vanadium for the same TBP cut point.[4] A properly designed vacuum unit can reduce HVGO vanadium content by 30-50%.

CRUDE BULK PROPERTIES Table 2

Crude type	Vanadium, ppmw	Viscosity at 100° F., cst	Salt content, lb/1,000 bbl of crude
Maya	291	95	6
Merey	295	461	40-60
Zuata	260	328	61
Cold Lake	124	75	20
Lloydminster (LLB)	100	70	42
Canadian blend	155	80	40

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MAYA VANADIUM DISTRIBUTION Fig. 3

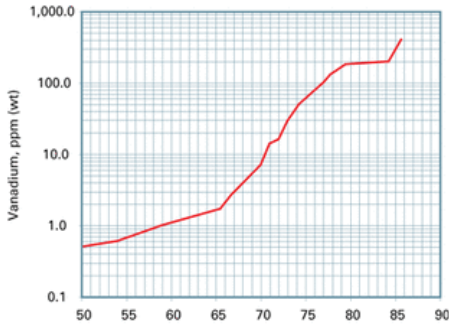

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Table 3 shows how CFHT feed vanadium content can increase for a poorly designed CDU heavy crude revamp. High ATB entrainment into the atmospheric gas oil (AGO) and high entrainment and poor fractionation in the vacuum unit caused the high CFHT feed vanadium content.

ATB and VTB produced from Maya crude will have nearly 550 ppm (wt) and 900 ppm (wt) vanadium, respectively. Operators must therefore eliminate all crude and vacuum column entrainment to minimize CFHT feed contaminants.

Because heavy crudes have more vacuum gas oils, vacuum column vapor velocities increase. Poorly distributed vapor entering the wash section creates high localized velocities that exceed the maximum limit for effective VTB deentrainment.

Some refiners have seen HVGO MCR and vanadium levels greater than 1 wt % and 10 ppm (wt), respectively, when processing 22° API gravity crudes.

Well designed flash-zone vapor horn and internals reduce entrainment; both are critical to minimize CFHT feed contaminants.[5]

CFHT FEED STREAM VANADIUM Table 3

Stream	Design vanadium, ppmw	Actual vanadium, ppmw
AGO	1.0	8.0
LVGO	0.4	0.4
HVGO	5.0	8.0

Click here to enlarge image

Some heavy crudes require metallurgical upgrades to higher-alloy materials due to high naphthenic acid (Table 4), high sulfur, and high crude-column overhead system chloride levels (Fig. 4). Crudes with a total acid number (TAN) of 2.4 will produce an HVGO TAN of 3.5 or greater.[6 7]

WHOLE TAN NUMBER Table 4

Crude type	Gravity, °API	TAN
Maya	22	0.4
BCF	17	2.5
Merey	16	1.2
Zuata	16	2.4
Cold Lake	20	1.0
Lloydminster (LLB)	19	0.7
Canadian blend	19	2.3

Click here to enlarge image

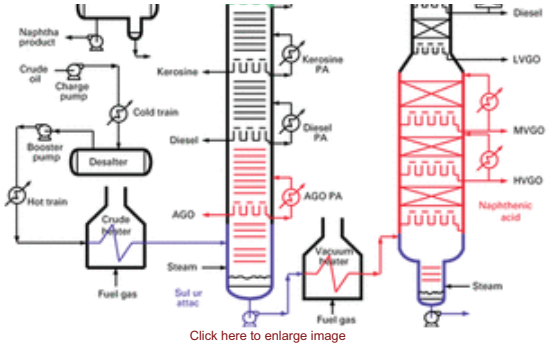
Metallurgy upgrades are needed for gas oil circuits that operate between 500° and 650° F. Piping and column internal components such as beams, packing supports, and tower attachments commonly use 317L. Some refiners use 904 stainless steel in the vacuum column for cladding and internals because it has a high molybdenum content, thus making it resistant to naphthenic acid attack.

Processing tar sands crudes creates some unique challenges. These crudes

METALLURGY UPGRADES Fig. 4

can have high sediment and clay contents and some blends also have high viscosity.

Desalter operations are more difficult and there is an increased likelihood of stable emulsion formation. If desalter performance deteriorates, the corrosion rate in the atmospheric column overhead system may increase and cause reliability problems.



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Maintaining crude charge rate

Revamp process flow schemes must account for the inherent crude hydraulics and preheat dilemma associated with processing heavy crudes while maintaining unit reliability.

Higher-viscosity heavy crudes reduce the crude-charge-pump developed head and can also increase exchanger fouling.

Circumventing hydraulic limits to achieve a desired crude feed rate can be expensive; therefore, a revamp must consider crude hydraulics early in the process to ensure there is sufficient capital to achieve processing objectives.

Crude charge hydraulics are not generally evaluated thoroughly enough until late in detailed engineering when they can result in scope growth, additional expenditure, or scope rationalization.

Crude charge rate will often decrease if preheat train modifications are not made. With heavy crudes, cold-exchanger-train heat transfer decreases because there is less heat available from the atmospheric column pumparounds and products.

These exchangers also have lower heat-transfer coefficients due to higher crude viscosity. Additional cold-train-exchanger surface area is needed to meet desalter temperatures necessary for efficient desalting.

To lower the cold-train pressure drop at the expense of crude velocity, refiners commonly install new exchangers parallel to existing exchangers or reduce the exchanger bundle tube passes on existing exchangers.

This approach causes increased exchanger fouling, which decreases heat-transfer coefficients and increases pressure drop.

For example, cold-train exchangers processing 100% Merey or BCF-17 operate in the laminar flow regime and have service heat-transfer coefficients as low as 12 btu/hr-sq ft-°F.

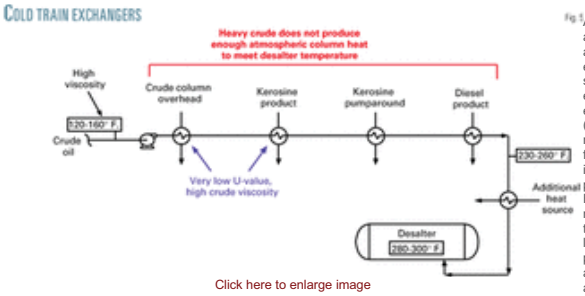

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Fig. 1 An alternate approach is adding exchangers in series with existing exchangers (Fig. 5), which minimizes fouling and increases pressure drop. Heavy crude revamps typically require larger charge pump motors and impellers and sometimes pump replacement.

New exchanger bundles are typically designed for higher maximum allowable working pressure (MAWP) to meet cold-train charge hydraulics. Designers must also evaluate pipe flange and exchanger pressure ratings for the higher head pumps. Several heavy-crude revamp designs included very little pressure drop available on the desalter pressure-control valve and crude-heater-pass balancing valves for start-of-run operation.

When exchangers are clean, design crude-charge rates were possible; however, as the exchangers foul, pressure drop increased and crude rate was reduced.

In some designs, the operator had to open exchanger bypasses to meet design charge rates when the exchangers fouled. This generally allows a higher crude rate, but it also lowers the temperature at the desalter, reduces atmospheric-column heat removal, raises atmospheric-column operating pressure, and increases product-rundown temperatures.

When revamping a preheat train to process heavy crude, the designer must use accurate viscosities, allow sufficient pressure drop allowance for fouling, and correct pump head-flow and efficiency curves for viscosity effects.

Product yield, quality

Many heavy crude blends contain less total atmospheric-plus-vacuum-column distillates and more ATB and VTB; therefore, high recovery of these distillates is important.

A well-designed crude unit can recover more distillates than inadequate process and equipment designs. In one case, for the same heavy crude a poorly designed flow scheme and equipment flaws yielded 20 vol % atmospheric distillates and 80 vol % ATB, whereas a proper design yielded about 33 vol % atmospheric distillate and 67 vol % ATB.

Processing heavier crudes can lower diesel product recovery, increase diesel boiling-range material in the CFHT feed, reduce HVGO recovery, increase CFHT contaminants, and increase <1,000° F. boiling-range material in the coker feed.

Higher heater temperature, lower atmospheric and vacuum-column operating pressures, lower atmospheric column overflash,[8] improved wash-section efficiency, and better ATB-VTB stripping are needed[9] to maintain product yield and quality.

Table 5 shows operating changes needed to maintain atmospheric and vacuum column ATB and VTB cut points.

Heavy crudes are difficult to vaporize in the crude heater alone. Diesel product cut point may vary 30° to 80° F. due to low diesel-AGO internal reflux, high column pressure, low pumparound-heat removal, high overflash rates, and ineffective stripping section performance.

Low diesel recovery causes a high feed rate to the CFHT or FCC and may limit refinery crude rate when these units are operating at maximum capacity.

OPERATING CHANGES TO PROCESS HEAVY CRUDES — Table 5

Variable	Atmospheric column	Vacuum column
Temperature	Higher	Higher
Pressure	Lower	Lower
Flash-zone oil partial pressure	Lower	Lower
Residue stripping efficiency	Higher	Higher

Click here to enlarge image

Because heavy crudes contain vanadium compounds that distill in the HVGO-product boiling range, increasing HVGO-product cut point will increase metals. The rate of increase is directly related to the process and equipment design.

Efficient VTB stripping lowers HVGO vanadium; yet most vacuum units are designed without VTB stripping. The few units that include a stripping section have tray efficiencies less than 10-15% due to poor tray design. These stripping sections can require higher steam rates, which increase condenser and ejector system capital and operating costs.

Reliability

Unit reliability means the unit can meet a targeted run length without significant deterioration in charge rate, product yield, or product quality. Poor reliability results in unscheduled shutdowns, significantly lower product yields and quality, or reduced unit charge rates.

Heavy crudes diminish unit reliability due to chronic heater coking,[10] condenser corrosion, crude-column tray fouling, or poor desalter operations.

Correcting these deficiencies requires capital investment; otherwise, realistic run lengths may only be 1-2 years vs. 4-5 years that many refiners target. Refiners must always balance revamp capital investment against run length.

Heavy crude viscosity can cause poor desalter performance. As desalter temperature drops, oil-water separation becomes problematic and the desalted-crude salt content increases. Some refiners processing heavy crudes have had to switch from series to parallel desalter operation to eliminate oil-water separation problems.

HYDROCHLORIC ACID CORROSION

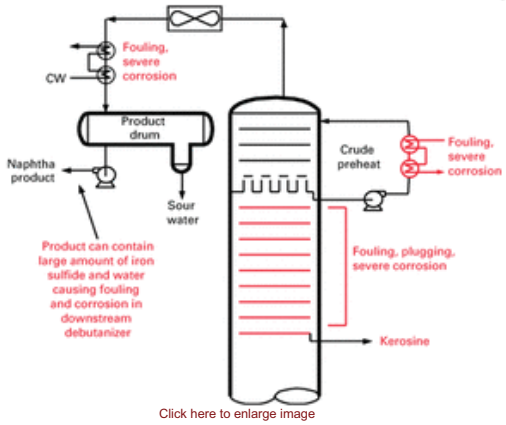

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Fig. 6 Single-stage desalting removes 90-95% of crude salt; desalted crudes may have salt contents of 3-6 lb/1,000 bbl. This high chloride content results in fouling and corrosion in the crude-column overhead condenser and an increased likelihood of column tray fouling (Fig. 6).

Revamp process design

Crude-unit process flow schemes should focus on crude properties, processing objectives, and design fundamentals. Heavy oil is inherently more difficult to vaporize because there is less light material in the feed.

Crude-unit designs must optimize ATB cut point to balance overall unit performance because it influences crude and vacuum column operations. The relationship between ATB and VTB cut points are complex and refiners must evaluate the columns and ancillary equipment as a single system.[11]

With a lower ATB cut point, there is less atmospheric flash-zone vapor available to provide pumparound and product heat to the cold exchanger crude preheat train. As diesel and AGO materials shift to the vacuum tower, less high-temperature heat is available for crude preheat.

Diesel and AGO pumparound and product temperatures are about 550° F. and 625° F., respectively. LVGO draw temperature is only about 330° F.; therefore diesel and AGO product yielded in the vacuum column provides little or no preheat. A lower HVGO product draw temperature can also result due to a lighter HVGO product.

Maximizing diesel recovery is important when crude rate is limited by CFHT or FCC unit capacity. This requires optimum atmospheric column diesel-AGO fractionation, ATB stripping, and AGO product stripping.

Good diesel-AGO product fractionation requires adequate reflux rate (liquid-vapor ratio), 8-10 trays, and good tray efficiency. Most atmospheric columns wider than 16 ft in diameter will use four-pass trays. These large-diameter towers have low weir loadings (gpm/in. weir) and the tray efficiencies can be low. Low reflux and tray efficiency dramatically reduce diesel yield.

An AGO pumparound increases crude preheat; however, if the ATB cut point is only 700° F., there is not enough vapor from the atmospheric column flash zone to provide sufficient internal reflux in the diesel-AGO fractionation section to allow heat removal from an AGO pumparound.

Operating with an AGO pumparound should be based on crude TBP distillation, acceptable diesel-AGO fractionation, and ATB cut point target, not standard design practices.

The vacuum-unit design depends on the HVGO product cut point target, vacuum heater design, crude vanadium distribution, and other detailed equipment design issues. HVGO product cut points are typically less than 975° F. when crudes with gravities less than 24° API are being processed.

A dry vacuum unit design uses no steam in the heater and does not have a stripping section. Maintaining cut point is difficult even with a well-designed unit using coil steam, but a dry vacuum unit simply cannot operate reliably at cut points greater than about 950° F. when processing Merey, Zuata, or BCF-17 crudes.

A heater without coil steam must operate at only 760-770° F. to avoid rapid coking from heavy crudes. HVGO product TBP cut points >1,000° F. require a heater outlet temperature of 795-800° F., low flash-zone oil partial pressure, and good VTB stripping.

Heavy crude increases total LVGO and HVGO pumparound duty requirements because more VGOs are yielded. A two-product vacuum column will have a high HVGO pumparound duty at a relatively low temperature of about 480-540° F. Increasing vacuum unit heat input requires more surface area and more HVGO pumparound capacity to remove the added heat.

Increasing HVGO pumparound duty typically requires increasing the number of exchangers in series because the log mean temperature difference is so low.

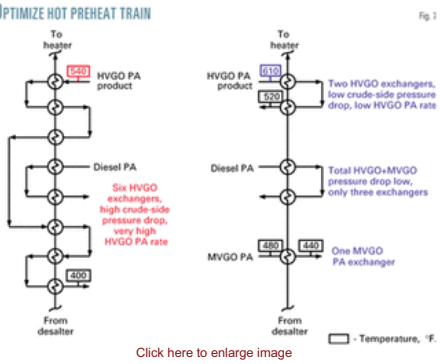
One refiner used six exchangers in series in the hot preheat train. Exchanger network design must address the increased pressure drop caused by additional exchangers.

This refiner can alternatively include an extra pumparound. A portion of the HVGO pumparound heat shifts to an MVGO pumparound. This increases the HVGO pumparound temperature to >600° F. and reduces the hot train preheat exchangers from six to three (Fig. 7).

When crude hydraulics are tight, a third pumparound can help alleviate crude bottlenecks. It can also reduce the required HVGO pumparound circulation rate to stay within existing pump and piping limits. A third vacuum-unit pumparound often results in the lowest overall cost solution (Fig. 8).

Revamp equipment design

Maximizing heavy oil vaporization, minimizing product contaminants,[12] and maintaining an acceptable run length requires fundamentally sound equipment design.



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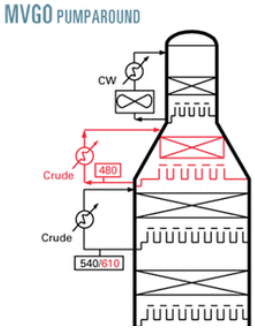
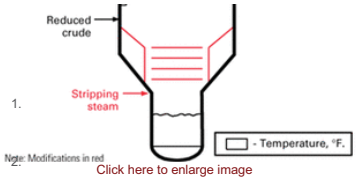


Vacuum heater, ATB and VTB stripping, and atmospheric and vacuum wash section designs influence unit performance.[13,14]

Refinery vacuum heaters need to operate at outlet temperatures between 790° and 800° F. while meeting run-length targets.[15]

Maximized ATB stripping efficiency requires adequate stripping steam, maximum trays, and maximum tray efficiency. VTB stripping and vacuum heater coil steam should balance with column operating pressure.

Atmospheric and vacuum column flash-zone vapor horn and wash sections should eliminate entrainment



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and the vacuum column needs to fractionate HVGO product to reduce the TBP curve 95%-EP tail. F

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RESEARCH LETTER
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Key Points:
- We identify a large increase in U.S. methane emissions over the past decade
- Increase occurred during a time when emission inventories indicate no change in U.S. emissions
- The U.S. could account for 30-60% of the global increase in atmospheric methane over the past decade

Supporting Information:
- Supporting Information S1

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A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observations

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Abstract The global burden of atmospheric methane has been increasing over the past decade, but the causes are not well understood. National inventory estimates from the U.S. Environmental Protection Agency indicate no significant trend in U.S. anthropogenic methane emissions from 2002 to present. Here we use satellite retrievals and surface observations of atmospheric methane to suggest that U.S. methane emissions have increased by more than 30% over the 2002–2014 period. The trend is largest in the central part of the country, but we cannot readily attribute it to any specific source type. This large increase in U.S. methane emissions could account for 30–60% of the global growth of atmospheric methane seen in the past decade.

1. Introduction

Methane is the second most important anthropogenic greenhouse gas, with a radiative forcing of 0.97 W m^{-2} since preindustrial times on an emission basis, as compared to 1.68 W m^{-2} for CO_2 [*Intergovernmental Panel on Climate Change* (*IPCC*), 2013]. The global burden of atmospheric methane rose by 1–2% a^{-1} in the 1970s and 1980s, stabilized in the 1990s [*Dlugokencky*, 2003], and has been rising again since the mid-2000s [*Rigby et al.*, 2008; *Dlugokencky et al.*, 2009]. There has been much speculation as to the cause for the recent trends with explanations including oil and gas production [*Wang et al.*, 2004; *Aydin et al.*, 2011; *Simpson et al.*, 2012; *Bruhwiler et al.*, 2014; *Franco et al.*, 2015], microbial sources [*Kai et al.*, 2011; *Levin et al.*, 2012], wetlands [*Dlugokencky et al.*, 2009; *Bousquet et al.*, 2011; *Pison et al.*, 2013; *Bergamaschi et al.*, 2013], and changes in the OH sink [*Fiore et al.*, 2006; *Rigby et al.*, 2008]. Here we show evidence from atmospheric observations to suggest that U.S. methane emissions have increased by more than 30% over the past decade, which would represent a major contribution to the global increase of methane concentrations.

Major anthropogenic sources of atmospheric methane include oil and gas systems, livestock (enteric fermentation and manure management), coal mining, and waste (landfills and wastewater). Wetlands are the dominant natural source. Oxidation by the hydroxyl radical is the main sink of methane, imposing an atmospheric lifetime of about 10 years [*IPCC*, 2013; *Kirschke et al.*, 2013]. The current global source of methane is constrained to 550 ± 60 Tg a^{-1} from knowledge of the global sink [*Prather et al.*, 2012]. However, estimating the contributions from different source types and regions is difficult due to spatial overlap in the sources and because sources mostly involve biological processes and fossil fuel losses that are hard to quantify [*Dlugokencky et al.*, 2011].

Methane emissions can be estimated using "bottom-up" methods that compute emissions as the product of activity rates (e.g., number of gas wells drilled) and emission factors per unit of activity (e.g., methane emission per well drilled), thus relating emissions to the underlying physical processes. Emission factors often have large uncertainties. Bottom-up estimates can be tested by "top-down" methods that use atmospheric observations of methane to constrain emissions on the basis of a chemical transport model relating emissions to concentrations. Inverse studies optimize emission estimates by combining bottom-up and top-down constraints, often using Bayesian inference.

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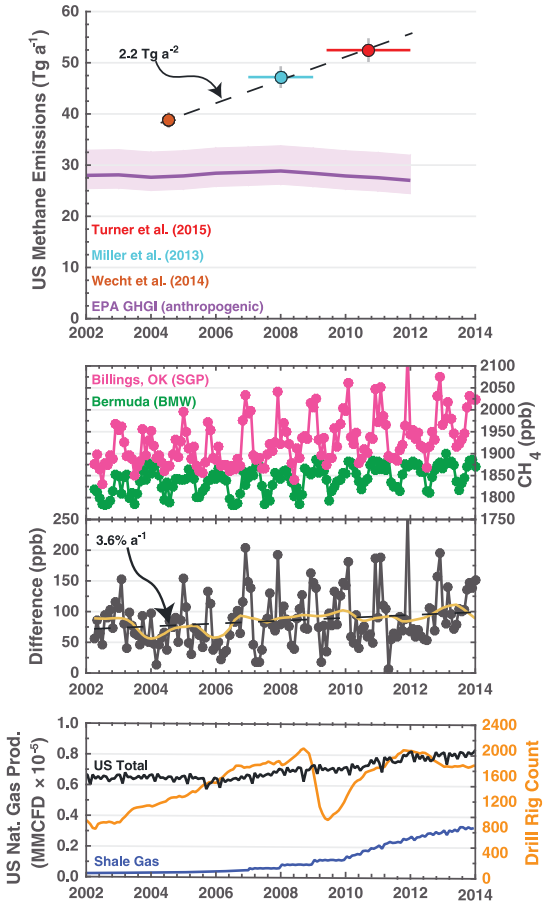

Figure 1. The 2002–2014 trends in U.S. methane emissions, atmospheric mixing ratios, and gas production rates. (top) The total contiguous U.S. (CONUS) methane emissions from three recent inverse studies [*Miller et al.*, 2013; *Wecht et al.*, 2014; *Turner et al.*, 2015] with horizontal bars indicating the temporal averaging periods and vertical bars indicating reported uncertainties. U.S. EPA anthropogenic emission estimates from the Greenhouse Gas Inventory for 2002–2012 are also shown, with shading indicating reported uncertainties [*US EPA*, 2014]. (middle) The monthly atmospheric methane mixing ratios measured in surface air by the U.S. DOE at the Southern Great Plains site [SGP; *Biraud et al.*, 2013] near Billings, Oklahoma (36.62°N, 97.48°W) and the NOAA/ESRL site (BMW) [*NOAA ESRL*, 2015] at Bermuda (32.27°N, 64.87°W), along with the corresponding SGP-BMW difference (black), a deseasonalized difference (gold line), and the ordinary least squares trend expressed as the percent change from 2004 (dashed black line). (bottom) The trend in CONUS oil and gas production and drilling activity as measured by active rig counts [*US EIA*, 2015] (number of active rigs at a given time). Oil and gas production data are from the U.S. Energy Information Administration.

2. U.S. Methane Emissions

The Greenhouse Gas Inventory of the U.S. Environmental Protection Agency [*US EPA*, 2014] provides the most detailed bottom-up estimate of U.S. anthropogenic methane emissions, following IPCC guidelines for reporting [*Eggleston et al.*, 2006]. Figure 1 shows yearly emissions from 2002 to 2012. Values vary between 27.0 and 28.9 Tg a^{-1} over the period with no significant trend. Over 98% of emissions are in the contiguous U.S. (CONUS), excluding Alaska, Hawaii, and Puerto Rico [*Maasakkers et al.*, 2015]. The EDGAR v4.2FT2010 global inventory [*European Commission*, 2013] also shows no significant trend in U.S. emissions from 2002 to 2010 (see Figure S10 in the supporting information). Major contributions in the U.S. EPA inventory and their interannual ranges are 30–32% from oil and gas, 31–34% from livestock, 21–22% from waste, and 10–13% from coal. Natural wetland emissions in CONUS are estimated to be 8.5 ± 5 Tg a^{-1} for 1993–2004 based on

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the Wetland CH4 Inter-comparison of Models Project ensemble of bottom-up models [*Melton et al.*, 2013; *Wania et al.*, 2013].

Recent work by *Wecht et al.* [2014], *Miller et al.* [2013], and *Turner et al.* [2015] used inverse methods to derive CONUS methane emissions of 38.8 ± 1.3, 47.2 ± 1.9, and 52.5 ± 2.1 Tg a^{-1}, respectively. *Wecht et al.* [2014] used Scanning Imaging Absorption Spectrometer for Atmospheric Chartography (SCIAMACHY) satellite data for July–August 2004. *Miller et al.* [2013] used NOAA Global Greenhouse Gas Reference Network in situ observations for 2007–2008 from ground stations and aircraft. *Turner et al.* [2015] used Greenhouse Gases Observing Satellite (GOSAT) data for June 2009 to December 2011. *Wecht et al.* [2014] found the total CONUS anthropogenic emissions to be consistent with the U.S. EPA bottom-up estimates, while *Miller et al.* [2013] and *Turner et al.* [2015] found much higher values. All three found maximum emissions in the South Central U.S., a region with large sources from livestock and oil and gas production. The reported uncertainties in these studies are likely too low because they do not properly account for systematic errors [*Peylin*, 2002; *Heald et al.*, 2004; *Ganesan et al.*, 2014]. The U.S. EPA inventory gives only national totals, so pinpointing specific regions of discrepancy is difficult, and the spatial overlap between livestock and oil and gas sources makes it difficult to attribute the high South Central U.S. emissions to a specific source type [*Turner et al.*, 2015]. A spatially resolved version of the U.S. EPA inventory is currently under development [*Maasakkers et al.*, 2015].

A possible factor contributing to the difference in CONUS emissions between the three inverse modeling studies is the time period investigated, as shown in Figure 1. Treating the results of the inverse studies as a time series and applying a least squares regression implies an increasing trend of 2.2 Tg a^{-2} in U.S. methane emissions. This corresponds to a 38% increase from 2004 to 2011 or a 5.4% a^{-1}. Natural gas production and drilling activity increased greatly during that period [*US EIA*, 2015] (Figure 1, bottom) though the U.S. EPA inventory indicates a 3% decrease in national oil and gas emissions over the period due to lower emission factors (better control of leaks).

3. Trends in U.S. Surface Observations

Long-term measurements of methane dry-air molar mixing ratios from the DOE/Atmospheric Radiation Measurement (ARM) Southern Great Plains (SGP) [*Biraud et al.*, 2013] site in central Oklahoma offer independent evidence of a CONUS emission trend. There are other surface sites in the CONUS (Figure S6), but SGP has one of the longest continuous records and is most centrally located. Figure 1 (middle) shows the 2002–2014 trend in the deseasonalized difference between methane measured at SGP and at the Tudor Hill Atmospheric Observatory in Bermuda (BMW) [*NOAA ESRL*, 2015], taken as a Northern Hemispheric background. The SGP-BMW difference shows a trend of 2.3 ppb a^{-1} ($p < 0.01$) from 2002 to 2014 and 3.9 ppb a^{-1} for the 2004–2011 period. This 2004–2011 period is relevant here because it is the time period covered by the inversion studies [*Miller et al.*, 2013; *Wecht et al.*, 2014; *Turner et al.*, 2015]. A similar trend is found when using the NOAA Mauna Loa Observatory site in Hawaii (MLO) [*NOAA ESRL*, 2015] as reference background (see Figure S7). We may expect the difference with SGP to reflect the footprint of U.S. emissions affecting SGP, which implies a relative increase in these emissions of 3.6% a^{-1} for 2002–2014 and 6.0% a^{-1} for the 2004–2011 time period covered by the inversion studies [*Miller et al.*, 2013; *Wecht et al.*, 2014; *Turner et al.*, 2015]. The 2004–2011 trend is larger because of the 2004 minimum apparent in Figure 1 and is consistent with the 5.4% a^{-1} CONUS trend for 2004–2011 implied by the inverse studies, as might be expected since SGP is in the South Central U.S. where inverse studies point to large underestimates in emissions. Scaling the SGP-BMW difference correspondingly would suggest a CONUS trend in methane emissions of 3.2% a^{-1} or 1.3 Tg a^{-2} for 2002–2014.

Bruhwiler et al. [2014] previously used a global inversion of NOAA/ESRL surface data to derive 2000–2010 emission trends for large continental regions. They found a 4 Tg a^{-1} increase in fossil fuel emissions from temperate North America (as defined by The Atmospheric Tracer Transport Model Intercomparison Project regions, which is larger than the CONUS) over that period (0.4 Tg a^{-2}). This is a factor of 3–4 lower than what we derive. Their results showed an increasing residual difference in the simulation of SGP concentrations over the 2000–2010 period, suggesting a larger trend in CONUS emissions than derived in their inversion. *Schneising et al.* [2014] found from SCIAMACHY satellite data that methane emissions grew by 1.5 Tg a^{-1} in the Bakken (North Dakota) and Eagle ford (Texas) oil and gas basins during 2006–2011, which alone would drive an increase of 5% a^{-1} in CONUS methane emissions. *Franco et al.* [2015] reported a $4.90 \pm 0.91\%$ a^{-1} rise of ethane concentrations over 2009–2014 at the Jungfraujoch

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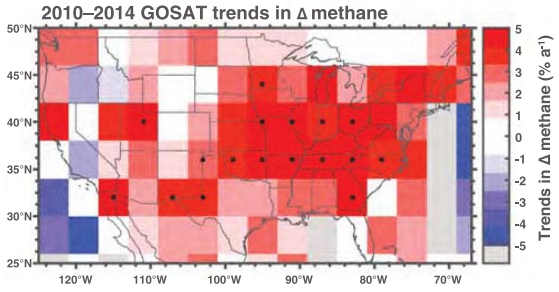

Figure 2. The 2010–2014 trend in U.S. methane enhancements as seen from GOSAT. The methane enhancement (Δ methane) is defined as the difference in the tropospheric column mixing ratio relative to the oceanic background measured in the glint mode over the North Pacific (176–128°W, 25–43°N) and normalized with the 2010 Δ methane. Trends are computed on a 4° × 4° grid. Statistically significant trends ($p < 0.01$) are indicated by a dot.

European mountain site and pointed to the growth of North American shale gas exploitation as a possible explanation. *Vinciguerra et al.* [2015] found an increase of ~6% a^{-1} in ethane concentrations in Maryland over 2010–2013 and attributed it to gas production in the Marcellus Shale upwind. They found no such increase in Atlanta, where there is no nearby oil and gas production.

4. Trends in GOSAT Satellite Data

The GOSAT satellite launched in Sun-synchronous low Earth orbit in January 2009 provides retrievals at sampling locations separated by 90–280 km along the orbit tracks. GOSAT has three observing modes: high gain (nominal setting over land), medium gain (setting over highly reflective surfaces), and ocean glint (setting over the ocean). We use RemoTeC v2.3.6 proxy methane retrievals [*Butz et al.*, 2011; *Schepers et al.*, 2012] (data available at http://www.temis.nl/climate/methane.html) in the high-gain nadir and ocean glint modes that pass all quality flags. The proxy methane retrieval method [*Frankenberg et al.*, 2006] assumes knowledge of the CO_2 concentration, and RemoTeC uses CO_2 concentrations from CarbonTracker including long-term trends [*Peters et al.*, 2007]. Validation with data from the Total Carbon Column Observing Network [*Wunch et al.*, 2011] shows that the RemoTeC retrieval has a single-scene precision of 14 ppb and a differential accuracy of 3 ppb [*Buchwitz et al.*, 2015].

GOSAT observations are spatially sparse, but they are temporally dense because the satellite always revisits the same ground pixels, every 3 days [*Kuze et al.*, 2009]. They are therefore well suited for temporal trend analyses. For example, the 4° × 4° pixel encompassing SGP has 1937 data points from January 2010 to January 2014 (see Figure S15). We examined the spatial distribution of GOSAT CONUS trends from January 2010 to January 2014, using ocean glint retrievals over the North Pacific to subtract the background and correcting for spatial differences in tropospheric contributions to the total columns on the basis of local orography. We refer to the difference between CONUS methane and North Pacific background for the corresponding latitude as the enhancement ("Δ methane") due to U.S. emissions. Pacific air generally provides a good estimate of the U.S. background at the corresponding latitude [*Benmergui et al.*, 2015]. To check the consistency in background trends between nadir and glint modes, we compared the two at southern mid-latitudes (using Patagonia for land) and found no significant differences (see Figure S5).

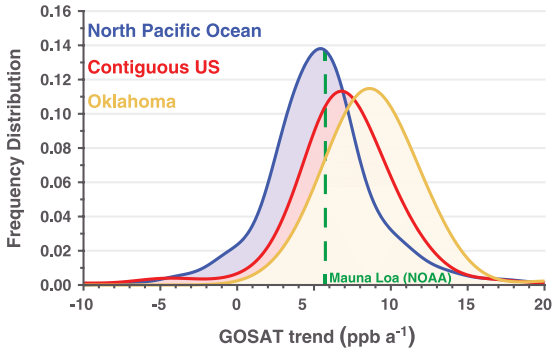

Figure 3. Spatial frequency distributions of 2010–2014 methane increases seen from GOSAT. Values are shown for the state of Oklahoma, the contiguous U.S. (CONUS), and the North Pacific (176–128°W, 25–43°N). The 2010–2014 trend at the NOAA Mauna Loa Observatory site (MLO) is also shown. GOSAT trends were computed on a 0.5° × 0.5° grid, weighted by the square root of the number of retrievals, and distributions were computed with kernel density estimation.

To obtain the orography-corrected Δ methane, we first normalize all the methane retrievals to account for variations in orography and tropopause height, similar to the approach of *Kort et al.* [2014]. The normalization is computed by determining the local (retrievals within a 300 km radial distance) relationship between column dry-air mole fraction (X_{CH_4}) in the GOSAT retrieval and the fraction of air

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in the troposphere (F_{trop}), using all GOSAT retrievals within a 300 km radius. F_{trop} is computed from the tropopause pressure in the NCEP/NCAR reanalysis [*Kalnay et al.*, 1996] and the surface pressure used in the GOSAT retrieval.

In this manner we obtain the methane enhancement (Δ methane) over the CONUS relative to the North Pacific at the same latitude as a difference in tropospheric columns. We then computed a 2010–2014 ordinary least squares trend in Δ methane for each 4° × 4° grid box. The horizontal resolution (4° × 4°) was chosen to minimize the impact of smearing due to atmospheric transport (see supporting information).

Figure 2 shows the spatial distribution of trends in GOSAT methane enhancements over CONUS from 2010 to 2014. The trends are expressed as percentage changes relative to the mean 2010 Δ methane. Figure S14 shows the absolute trend in Δ methane. We find statistically significant ($p < 0.01$) increasing trends across the Midwest. Trends are weaker and/or insignificant in the West and over the eastern seaboard. Trends in Δ methane can be expected to be proportional to trends in CONUS emissions, and the corresponding emission trend averaged over the CONUS ($2.8 \pm 0.3\%$ a^{-1}) is comparable to those inferred in Figure 1 from the inverse studies and the surface sites.

Figure 3 shows the frequency distribution of GOSAT 2010–2014 trends for three selected regions: (1) the background North Pacific (176–128°W, 25–43°N), (2) the CONUS, and (3) the state of Oklahoma (for relation to the SGP site). Also shown is the trend inferred from surface observations at the MLO site for 2010–2014. North Pacific GOSAT trends are consistent with MLO, providing a check on the background trend used in our analysis. Using a Metropolis-Hastings algorithm, we find that trends in the CONUS distribution are 1.7 ppb a^{-1} larger than the background, a significant difference ($p < 0.01$), corresponding to a relative increase in Δ methane of 2.5% a^{-1} over the 2010–2014 period. Trends in Oklahoma are 3.2 ppb a^{-1} larger than background, corresponding to a relative increase in Δ methane of 4.7% a^{-1}.

5. Discussion

Long-term surface observations and satellite retrievals of atmospheric methane, interpreted directly and using inverse methods, point to an increase of more than 30% in U.S. methane emissions over the past decade. The increase is largest in the central part of the country. The U.S. has seen a 20% increase in oil and gas production [*US EIA*, 2015] and a ninefold increase in shale gas production from 2002 to 2014 (Figure 1, bottom), but the spatial pattern of the methane increase seen by GOSAT does not clearly point to these sources. More work is needed to attribute the observed increase to specific sources.

Kirschke et al. [2013] found that the renewed growth in atmospheric methane between 2005 and 2010 could be explained by a 17–22 Tg a^{-1} increase in global methane emissions. Our results suggest that increasing U.S. anthropogenic methane emissions could account for up to 30–60% of this global increase. Other studies have pointed to tropical sources as a major driver for this increase [*Bousquet et al.*, 2011; *Bergamaschi et al.*, 2013]. Better understanding of U.S. anthropogenic methane emissions, particularly those from the livestock and oil and gas sectors, is obviously needed.

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Erratum

Edward Dlugokencky had been listed as an author on the submitted manuscript but was removed from the final published version by mutual agreement. His contribution has been described in the Acknowledgment.

Methane leaks erode green credentials of natural gas

Losses of up to 9% show need for broader data on US gas industry's environmental impact.

02 January 2013

David Zalubowski/AP Photo

Natural-gas wells such as this one in Colorado are increasingly important to the US energy supply.

Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system.

The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.

“We were expecting to see high methane levels, but I don’t think anybody really comprehended the true magnitude of what we would see,” says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA’s Earth System Research Laboratory in Boulder.

Whether the high leakage rates claimed in Colorado and Utah are typical across the US natural-gas industry remains unclear. The NOAA data represent a “small snapshot” of a much larger picture that the broader scientific community is now assembling, says Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF) in Boston, Massachusetts.

The NOAA researchers collected their data in February as part of a broader analysis of air pollution in the Uinta Basin, using ground-based equipment and an aircraft to make detailed measurements of various pollutants, including methane concentrations. The researchers used atmospheric modelling to calculate the level of methane emissions required to reach those concentrations, and then compared that with industry data on gas production to obtain the percentage escaping into the atmosphere through venting and leaks.

The results build on those of the earlier Colorado study[1] in the Denver–Julesburg Basin, led by NOAA scientist Gabrielle Pétron (see Nature 482, 139–140; 2012). That study relied on pollution measurements taken in 2008 on the ground and from a nearby tower, and estimated a leakage rate that was about twice as high as official figures suggested. But the team’s methodology for calculating leakage — based on chemical analysis of the pollutants — remains in dispute. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, published a peer-reviewed comment[2] questioning the findings and presenting an alternative interpretation of the data that would align overall leakage rates with previous estimates.

Pétron and her colleagues have a defence of the Colorado study in press[3], and at the AGU meeting she discussed a new study of the Denver–Julesburg Basin conducted with scientists at Picarro, a gas-analyser manufacturer based in Santa Clara, California. That study relies on carbon isotopes to differentiate between industrial emissions and methane from cows and feedlots, and the preliminary results line up with their earlier findings.

A great deal rides on getting the number right. A study[4] published in April by scientists at the EDF and Princeton University in New Jersey suggests that shifting to natural gas from coal-fired generators has immediate climatic benefits as long as the cumulative leakage rate from natural-gas production is below 3.2%; the benefits accumulate over time and are even larger if the gas plants replace older coal plants. By comparison, the authors note that the latest estimates from the US Environmental Protection Agency (EPA) suggest that 2.4% of total natural-gas production was lost to leakage in 2009.

To see if that number holds up, the NOAA scientists are also taking part in a comprehensive assessment of US natural-gas emissions, conducted by the University of Texas at Austin and the EDF, with various industry partners. The initiative will analyse emissions from the production, gathering, processing, long-distance transmission and local distribution of natural gas, and will gather data on the use of natural gas in the transportation sector. In addition to scouring through industry data, the scientists are collecting field measurements at facilities across the country. The researchers expect to submit the first of these studies for publication by February, and say that the others will be complete within a year.

In April, the EPA issued standards intended to reduce air pollution from hydraulic-fracturing operations — now standard within the oil and gas industry — and advocates say that more can be done, at the state and national levels, to reduce methane emissions. “There are clearly opportunities to reduce leakage,” says Hamburg.

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Tesoro eyeing Bakken pipeline, storage

The Mandan Tesoro Refinery is aiming to acquire assets in the Bakken.

Should the deal go through, Tesoro will be capable of pumping roughly 65,000 barrels of oil out of the Bakken each day.

Awaiting regulatory approval, Tesoro agreed last week to acquire Great Northern Midstream LLC and its crude oil pipeline, gathering system and storage and rail loading facilities in the state.

Assets include the 97-mile BakkenLink crude oil pipeline, which connects to several third-party gathering systems, a 28-mile gathering system in the core of the Bakken, where most of the drilling in today's low price environment is being done, a 154,000 barrel-per-day rail loading and a 657,000 barrel storage facility in Fryburg.

Tesoro already has the Tesoro High Plains Pipeline, which pumps crude oil directly into the company's 68,000 barrel-per-day refinery in Mandan.

"This acquisition would not substantially change the way we move product to our Mandan Refinery. We expect our enhanced system to provide Tesoro's West Coast facilities with cost-effective access to advantaged crude oil and provide producers additional market access. Customers gain additional flexibility from the rail loading and storage facility, which can provide outbound deliveries to the West, East and Gulf coasts," Tesoro spokesperson Brendan Smith said in an emailed statement.

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The High Plains Pipeline already granted the company access to the Bakken's core, said Justin Kringstad of the North Dakota Pipeline Authority. What BakkenLink adds is capacity: 65,000 barrels daily of it, according to 2014 filings with the state.

Kringstad said the rail terminal and storage are another major benefit. It gives the company the flexibility to hold crude oil in the state if the added cost of transportation makes the product unprofitable. With the terminal, the company can store it without having to stop pipeline flow or oil production.

"Our acquisition of Great Northern Midstream is aligned with our strategy to grow our logistics business, supply advantaged crude oil to our refineries and make these assets available to third-party customers," Greg Goff, CEO of Tesoro Corporation, said in a statement. "Combining the Great Northern Midstream assets with our Tesoro High Plains Pipeline will create a leading crude oil pipeline system in the most prolific region of the Bakken."

A price is not being named for the deal but, according to a Tesoro statement, the acquisition represents five to six times Tesoro's estimated future earnings before interest, taxes and amortization for the Great Northern Midstream business. The company expects it to immediately add to earnings.

The deal is expected to close in the first quarter of 2016.

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Tags

Emissions from Canada's oil-sand crude higher than those from U.S. sources

https://www.ucdavis.edu/news/emissions-canadas-oil-sand-crude-higher-those-us-sources

Emissions from Canada's oil-sand crude higher than those from U.S. sources

By Kat Kerlin on June 25, 2015 in

Crude oil extracted from Canadian tar sand pits, like this one, release more carbon emissions than crude from U.S. sources.

Gasoline and diesel fuel extracted and refined from Canadian oil sands will release about 20 percent more carbon into the atmosphere over the oil's lifetime than fuel from conventional crude sources in the United States, according to a study by the U.S. Department of Energy's Argonne National Laboratory; the University of California, Davis; and Stanford University.

The researchers used a life-cycle, or "well-to-wheels," approach, gathering publicly available data on 27 large Canadian oil sands production facilities. The study, published in the journal *Environmental Science and Technology*, found the additional carbon impact of Canadian oil sands was largely related to the energy required for extraction and refining.

"The level of detail provided in this study is unprecedented," said co-author Sonia Yeh, a research scientist at the Institute of Transportation Studies at UC Davis, who helped lead research on emissions related to land disturbance. "It provides a strong scientific basis for understanding the total carbon emissions associated with using this resource, which allows us to move forward with informed discussions on technologies or policy options to reduce carbon emissions."

Crude estimates

Canadian oil sands are extracted using two processes, both of which are energy intensive. Oil close to the surface can be mined, but still must be heated to separate the oil from the sand. Deeper sources of oil are extracted on-site, also called *in situ* extraction, requiring even more energy when steam is injected underground, heating the oil to the point it can be pumped to the surface. The extracted oil product, known as bitumen, can be moved to refineries in the United States or refined on-site to upgraded synthetic crude.

On-site extraction tends to be more carbon intensive than surface mining, and producing refined synthetic crude generally requires more carbon emissions than producing bitumen. Depending on which methods are used, the carbon intensity of finished gasoline can vary from 8 percent to 24 percent higher than that from conventional U.S. crudes.

"This is important information about the greenhouse gas impact of this oil source," said lead author and Argonne researcher Hao Cai. "Canadian oil sands accounted for about 9 percent of the total crude processed in U.S. refineries in 2013, but that percentage is projected to rise to 14 percent in 2020."

The research was funded by the Bioenergy Technologies Office and Vehicle Technologies Office within DOE's Office of Energy Efficiency and Renewable Energy.

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Flare Event Data

Rev. 05/18/06

Facility ID#	Flare Name	Flare Event Type	Flare Event Start Date	Flare Event Start Time	Flare Event Stop Date	Flare Event Stop Time	Date Representa-tive Sample Obtained	Time Representa-tive Sample Obtained	Total Flare Event Gas Flow Data Source	Total Flare Event Gas Flow	HHV Data Source	HHV	[S] as SO2 Data Source	[S] as SO2	PM10	NOx	ROG	CO	Total S as SO2	Category of Flare Event	Date Specific Cause Analysis Submitted
			(mm/dd/yy)	(hh:mm)	(mm/dd/yy)	(hh:mm)	(mm/dd/yy)	(hh:mm)		(Mscf)		(Btu/scf)		(ppm)	(lbs.)	(lbs.)	(lbs.)	(lbs.)	(lbs.)		(mm/dd/yy)
174655	Coker	2	1/2/2015	3:32	1/2/2015	6:12	1/2/2015	3:32	2	5.60	5	782.54	5	924.40	0.12	0.30	0.28	1.62	0.86	3	n/a
174655	Coker	2	1/11/2015	4:47	1/11/2015	7:22	1/11/2015	4:47	2	5.17	5	799.20	5	75.12	0.11	0.28	0.26	1.53	0.06	3	n/a
174655	Coker	2	2/2/2015	7:11	2/2/2015	12:55	2/2/2015	7:11	2	14.16	5	613.53	5	886.35	0.28	0.59	0.55	3.21	2.09	3	n/a
174655	Coker	2	2/2/2015	14:38	2/3/2015	14:38	2/2/2015	14:38	2	7.94	5	958.12	5	317.96	0.17	0.52	0.48	2.81	0.42	3	n/a
174655	Coker	2	2/13/2015	11:20	2/14/2015	11:20	2/13/2015	11:20	2	5.00	5	971.13	5	90.21	0.11	0.33	0.31	1.80	0.08	10	n/a
174656	Coker	3	2/24/2015	16:03	2/24/2015	21:41	2/24/2015	16:03	2	84.94	5	1696.27	5	47036.68	1.78	9.80	9.08	53.31	664.01	3	3/26/2015
174655	FCC	4	1/2/2015	3:33	1/2/2015	4:53	1/2/2015	3:33	2	0.88	5	1055.42	5	0.00	0.02	0.06	0.06	0.34	0.00	10	n/a
174655	FCC	2	1/11/2015	4:48	1/11/2015	6:27	1/11/2015	4:48	2	16.59	5	776.29	5	95.83	0.34	0.88	0.81	4.77	0.26	3	n/a
174655	FCC	2	2/2/2015	7:11	2/2/2015	8:49	2/2/2015	7:11	2	28.86	5	632.43	6	829.15	0.60	1.24	1.15	6.75	3.98	3	n/a
174655	FCC	4	2/2/2015	15:50	2/2/2015	17:30	2/2/2015	15:50	2	0.87	5	938.10	6	813.86	0.02	0.06	0.05	0.30	0.12	10	n/a
174655	5Flare	1	2/2/2015	15:50	2/2/2015	23:59	2/2/2015	15:50	2	605.91	5	743.53	5	4.94	12.73	30.63	28.38	166.69	0.50	3	2/26/2015
174655	5Flare	1	2/3/2015	0:00	2/3/2015	23:59	2/3/2015	0:00	2	1570.28	5	821.44	5	1.11	33.16	87.71	81.26	477.26	0.29	3	2/26/2015
174655	5Flare	1	2/4/2015	0:00	2/4/2015	11:22	2/4/2015	0:00	2	5736.18	5	683.41	5	0.19	120.30	266.57	246.97	1450.47	0.18	4	2/26/2015
174655	FFHDS	2	1/2/2015	3:33	1/2/2015	5:18	1/2/2015	3:33	2	23.56	5	676.99	5	1047.19	0.49	1.08	1.00	5.90	4.10	3	n/a
174655	FFHDS	4	1/11/2015	4:48	1/11/2015	6:31	1/11/2015	4:48	2	3.38	5	944.39	5	1.16	0.07	0.22	0.20	1.18	0.00	10	n/a
174655	FFHDS	1	2/2/2015	7:12	2/2/2015	11:42	2/2/2015	7:12	2	2300.61	5	500.12	5	1.89	48.27	78.24	72.49	425.71	0.72	3	2/26/2015
174655	FFHDS	4	2/2/2015	15:50	2/2/2015	17:30	2/2/2015	15:50	2	0.89	5	948.44	6	3662.17	0.02	0.06	0.05	0.31	0.54	10	n/a
174655	HC	4	1/2/2015	3:32	1/2/2015	5:22	1/2/2015	3:32	2	3.49	5	1084.92	5	0.00	0.07	0.26	0.24	1.40	0.00	10	n/a
174655	HC	1	1/11/2015	4:47	1/11/2015	10:19	1/11/2015	4:47	2	2137.40	5	425.96	6	4024.58	44.77	61.91	57.36	336.86	1429.68	3	2/9/2015
174655	HC	2	1/16/2015	9:57	1/16/2015	11:40	1/16/2015	9:57	2	73.75	5	424.59	5	107.28	1.55	2.13	1.97	11.59	1.31	3	n/a
174655	HC	4	1/20/2015	8:31	1/20/2015	10:02	1/20/2015	8:31	2	4.46	5	697.01	5	16.84	0.09	0.21	0.20	1.15	0.01	10	n/a
174655	HC	1	2/2/2015	7:11	2/2/2015	17:43	2/2/2015	7:11	2	4782.56	5	662.50	6	4031.62	100.35	215.45	199.61	1172.32	3204.58	3	2/26/2015

Note: Emission factors are from Rule 1118 Attachment B (ROG: 0.063 lb/mmBTU, NOx: 0.068 lb/mmBTU, CO: 0.37 lb/mmBTU, PM10: 21 lb/mmSCF, SOx: concentration of total sulfur * 0.1662))

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Daily Gas Flow and Emissions

			Gas Flow			Emissions				Exempt Emissions	
Facility ID	Flare Name	Date	Total Daily Vent Gas Flow	Total Daily Purge Gas Flow(1)	Total Daily Pilot Gas Flow	Total PM10	Total NOx	Total ROG	Total CO	Total S as SO2	Vent Gas Flow (due to ER or Force Majeure)	S as SO2 (due to ER or Force Majeure)
		(mm/dd/yy)	Mscf	Mscf	Mscf	lbs.	lbs.	lbs.	lbs.	lbs.	Mscf	lbs.
800436	LAR	10/1/2014	0.000	86.012	6.608	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/2/2014	0.000	84.999	6.578	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/3/2014	0.000	85.482	6.618	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/4/2014	26.250	85.664	6.644	0.60	3.22	2.23	13.04	2.93	0.00	0.00
800436	LAR	10/5/2014	0.000	85.642	6.807	0.05	0.88	0.05	0.24	0.01	0.00	0.00
800436	LAR	10/6/2014	0.000	85.777	6.687	0.05	0.87	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/7/2014	0.000	85.735	6.652	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/8/2014	0.000	86.043	6.626	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/9/2014	0.000	86.218	6.682	0.05	0.87	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/10/2014	0.000	86.014	6.637	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/11/2014	0.000	86.218	6.589	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/12/2014	0.000	86.171	6.582	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/13/2014	0.000	86.152	6.539	0.05	0.85	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/14/2014	0.000	86.189	6.550	0.05	0.85	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/15/2014	0.000	85.939	6.523	0.05	0.85	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/16/2014	0.000	85.978	6.503	0.05	0.85	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/17/2014	380.640	86.099	6.654	8.04	17.72	15.66	91.92	112.18	0.00	0.00
800436	LAR	10/18/2014	0.000	85.753	6.617	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/19/2014	36.538	86.091	6.556	0.82	2.05	1.16	6.77	20.49	0.00	0.00
800436	LAR	10/20/2014	0.000	86.072	6.593	0.05	0.86	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/21/2014	0.000	86.225	6.536	0.05	0.85	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/22/2014	0.000	85.986	6.480	0.05	0.84	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/23/2014	0.000	85.868	6.442	0.05	0.84	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/24/2014	0.000	85.868	6.482	0.05	0.84	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/25/2014	0.000	85.930	6.404	0.05	0.83	0.04	0.22	0.01	0.00	0.00
800436	LAR	10/26/2014	0.000	85.965	6.451	0.05	0.84	0.05	0.23	0.01	0.00	0.00
800436	LAR	10/27/2014	0.000	86.022	6.422	0.05	0.83	0.04	0.22	0.01	0.00	0.00
800436	LAR	10/28/2014	0.000	86.095	6.401	0.05	0.83	0.04	0.22	0.01	0.00	0.00
800436	LAR	10/29/2014	0.000	85.879	6.371	0.05	0.83	0.04	0.22	0.01	0.00	0.00
800436	LAR	10/30/2014	0.000	86.054	6.369	0.05	0.83	0.04	0.22	0.01	0.00	0.00
800436	LAR	10/31/2014	0.000	86.190	6.446	0.05	0.84	0.05	0.23	0.01	0.00	0.00
800436	LAR	11/1/2014	0.000	85.747	7.304	0.05	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/2/2014	0.000	85.828	7.324	0.05	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/3/2014	17.027	85.894	7.338	0.41	2.79	1.75	10.22	0.80	0.00	0.00
800436	LAR	11/4/2014	0.000	86.038	7.315	0.05	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/5/2014	0.000	85.563	7.311	0.05	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/6/2014	0.000	85.859	7.335	0.06	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/7/2014	0.000	87.119	7.364	0.06	0.96	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/8/2014	0.000	87.150	7.352	0.06	0.96	0.05	0.26	0.01	0.00	0.00
800436	LAR	11/9/2014	19.935	87.141	7.165	0.47	2.11	1.14	6.67	1.05	0.00	0.00

Daily Gas Flow and Emissions

Facility ID	Flare Name	Date	Gas Flow			Emissions				Exempt Emissions	
			Total Daily Vent Gas Flow	Total Daily Purge Gas Flow(1)	Total Daily Pilot Gas Flow	Total PM10	Total NOx	Total ROG	Total CO	Total S as SO2	Vent Gas Flow (due to ER or Force Majeure)	S as SO2 (due to ER or Force Majeure)
		(mm/dd/yy)	Mscf	Mscf	Mscf	lbs.	lbs.	lbs.	lbs.	lbs.	Mscf	lbs.
800436	LAR	11/10/2014	0.000	87.161	7.158	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/11/2014	0.000	87.288	7.149	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/12/2014	0.000	86.827	7.139	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/13/2014	0.000	86.931	7.084	0.05	0.92	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/14/2014	0.000	87.041	7.283	0.05	0.95	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/15/2014	0.000	87.303	7.263	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/16/2014	0.000	87.162	7.239	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/17/2014	0.000	87.135	7.230	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/18/2014	18.526	87.193	7.249	0.44	1.71	0.76	7.58	0.84	0.00	0.00
800436	LAR	11/19/2014	0.000	87.226	7.230	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/20/2014	0.000	87.033	7.214	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/21/2014	0.000	86.898	7.168	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/22/2014	0.000	87.220	7.194	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/23/2014	0.000	87.163	7.115	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/24/2014	0.000	87.255	7.117	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/25/2014	0.000	87.232	7.104	0.05	0.92	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/26/2014	0.000	87.349	7.089	0.05	0.92	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/27/2014	0.000	87.376	7.107	0.05	0.92	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/28/2014	0.000	87.185	7.059	0.05	0.92	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/29/2014	0.000	87.311	7.167	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	11/30/2014	0.000	87.374	7.266	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/1/2014	0.000	87.281	7.280	0.05	0.95	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/2/2014	0.000	87.075	7.319	0.05	0.95	0.05	0.26	0.01	0.00	0.00
800436	LAR	12/3/2014	0.000	87.212	7.434	0.06	0.97	0.05	0.26	0.01	0.00	0.00
800436	LAR	12/4/2014	0.000	87.299	7.246	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/5/2014	0.000	87.298	7.263	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/6/2014	0.000	87.509	7.219	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/7/2014	0.000	87.372	7.219	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/8/2014	0.000	87.343	7.211	0.05	0.94	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/9/2014	0.000	87.264	7.190	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/10/2014	0.000	87.229	7.151	0.05	0.93	0.05	0.25	0.01	0.00	0.00
800436	LAR	12/11/2014	0.000	87.247	3.808	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/12/2014	0.000	87.145	3.838	0.03	0.50	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/13/2014	0.000	86.957	3.794	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/14/2014	0.000	86.917	3.790	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/15/2014	0.000	87.100	3.802	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/16/2014	0.000	86.950	3.766	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/17/2014	0.000	87.062	3.792	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/18/2014	0.000	86.983	3.791	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/19/2014	34.632	87.156	3.754	0.76	3.51	2.83	16.59	1.36	0.00	0.00
800436	LAR	12/20/2014	0.000	87.241	3.733	0.03	0.49	0.03	0.13	0.00	0.00	0.00

Daily Gas Flow and Emissions

			Gas Flow			Emissions					Exempt Emissions	
Facility ID	Flare Name	Date	Total Daily Vent Gas Flow	Total Daily Purge Gas Flow(1)	Total Daily Pilot Gas Flow	Total PM10	Total NOx	Total ROG	Total CO	Total S as SO2	Vent Gas Flow (due to ER or Force Majeure)	S as SO2 (due to ER or Force Majeure)
		(mm/dd/yy)	Mscf	Mscf	Mscf	lbs.	lbs.	lbs.	lbs.	lbs.	Mscf	lbs.
800436	LAR	12/21/2014	0.000	87.213	3.738	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/22/2014	0.000	87.083	3.721	0.03	0.48	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/23/2014	0.000	86.927	3.728	0.03	0.48	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/24/2014	0.000	87.120	3.687	0.03	0.48	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/25/2014	0.000	86.999	3.777	0.03	0.49	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/26/2014	85.179	87.259	3.678	1.82	9.98	8.83	51.84	492.24	0.00	0.00
800436	LAR	12/27/2014	0.714	87.069	3.663	0.04	0.53	0.07	0.41	1.76	0.00	0.00
800436	LAR	12/28/2014	0.000	86.974	3.668	0.03	0.48	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/29/2014	0.000	87.012	3.662	0.03	0.48	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/30/2014	0.000	86.876	3.614	0.03	0.47	0.03	0.13	0.00	0.00	0.00
800436	LAR	12/31/2014	0.000	86.720	3.631	0.03	0.47	0.03	0.13	0.00	0.00	0.00
			619.441	*Subtotals*	9162.115	17	111	38	223	634	0	0
				Total Quarterly Emissions, less Exempt Emissions		17	111	38	223	634		

Vent Gas is any gas generated at a facility subject to this rule that is routed to a flare, exculding assisting air or steam, which is injected in the flare combustion zone or flare stack via separate lines.

Purge Gas is a continuous gas stream introduced into a flare header, flare stack and/or flare tip for the purpose of maintaining a positive flow that prevents the formation of an explosive mixture due to ambient air ingress.

(1) Purge gas to both LARW Flares was nitrogen during the 4th Quarter of 2014. Therefore, there were no combustion emissions from purge gas.

Flare Event Data

Facility ID#	Flare Name	Flare Event Type	Flare Event Start Date	Flare Event Start Time	Flare Event Stop Date	Flare Event Stop Time	Date Representative Sample Obtained	Time Representative Sample Obtained	Total Flare Event Gas Flow Data Source	Total Flare Event Gas Flow	HHV Data Source	HHV	[S] as SO2 Data Source	[S] as SO2	PM10	NOx	ROG	CO	Total S as SO2	Category of Flare Event	Date Specific Cause Analysis Submitted
			(mm/dd/yy)	(hh:mm)	(mm/dd/yy)	(hh:mm)	(mm/dd/yy)	(hh:mm)		(Mscf)		(Btu/scf)		(ppm)	(lbs.)	(lbs.)	(lbs.)	(lbs.)	(lbs.)		(mm/dd/yy)
800436	LAR	4	1/14/14	9:30:00	1/14/14	9:38:00	--	--	2	2.651	5	575	5	1761.0	0.06	0.10	0.10	0.56	0.78	4	NA
800436	LAR	4	1/14/14	10:37:00	1/14/14	10:42:00	--	--	2	1.278	5	965	5	1357.0	0.03	0.08	0.08	0.46	0.29	4	NA
800436	LAR	4	1/15/14	16:16:00	1/15/14	16:20:00	--	--	2	0.869	5	727	5	1417.0	0.02	0.04	0.04	0.23	0.20	4	NA
800436	LAR	4	1/15/14	17:20:00	1/15/14	17:24:00	--	--	2	2.304	5	608	5	781.0	0.05	0.10	0.09	0.52	0.30	4	NA
800436	LAR	2	1/24/14	6:58:00	1/24/14	7:28:00	--	--	2	10.199	5	1174	5	985.0	0.21	0.81	0.75	4.43	1.67	3	NA
800436	LAR	2	1/25/14	2:24:00	1/25/14	2:55:00	--	--	2	19.639	5	686	5	2153.0	0.41	0.92	0.85	4.98	7.03	5	NA
800436	LAR	2	1/25/14	3:52:00	1/25/14	4:09:00	--	--	2	5.704	5	557	5	953.0	0.12	0.22	0.20	1.18	0.90	5	NA
800436	LAR	2	1/25/14	4:38:00	1/25/14	5:33:00	--	--	2	15.796	5	363	5	429.0	0.33	0.39	0.36	2.12	1.13	5	NA
800436	LAR	2	1/25/14	7:31:00	1/25/14	8:02:00	--	--	2	324.195	5	413	5	81.0	6.81	9.10	8.44	49.54	4.36	4	NA
800436	LAR	2	1/27/14	4:17:00	1/27/14	5:25:00	--	--	2	149.316	5	1367	5	41957.0	3.14	13.88	12.86	75.52	1041.22	3	2/26/14
800436	LAR	4	2/4/14	18:35:00	2/4/14	18:40:00	--	--	2	3.030	5	1141	5	437.0	0.06	0.24	0.22	1.28	0.22	4	NA
800436	LAR	2	2/5/14	11:24:00	2/5/14	11:42:00	--	--	2	22.716	5	1291	5	1005.0	0.48	1.99	1.85	10.85	3.79	6	NA
800436	LAR	4	2/26/14	6:56:00	2/26/14	7:01:00	--	--	2	3.589	5	893	5	3138.0	0.08	0.22	0.20	1.19	1.87	4	NA
800436	LAR	4	2/26/14	8:10:00	2/26/14	8:15:00	--	--	2	0.509	5	673	5	1087.0	0.01	0.02	0.02	0.13	0.09	10	NA
800436	LAR	4	2/26/14	8:49:00	2/26/14	8:56:00	--	--	2	0.882	5	632	5	681.0	0.02	0.04	0.04	0.21	0.10	10	NA
800436	LAR	4	2/26/14	13:07:00	2/26/14	13:18:00	--	--	2	1.718	5	553	5	8.0	0.04	0.06	0.06	0.35	0.00	10	NA
800436	LAR	2	3/11/14	15:02:00	3/11/14	16:51:00	--	--	2	20.376	5	538	5	447.0	0.43	0.75	0.69	4.06	1.51	4	NA
800436	LAR	2	3/27/14	14:21:00	3/27/14	14:32:00	--	--	2	18.009	5	1021	5	502.0	0.38	1.25	1.16	6.80	1.50	3	NA
800436	LAR	4	3/27/14	18:57:00	3/27/14	18:58:00	--	--	2	0.175	5	856	5	44.0	0.00	0.01	0.01	0.06	0.00	10	NA
800436	LAR	4	3/27/14	19:23:00	3/27/14	19:24:00	--	--	2	0.147	5	908	5	45.0	0.00	0.01	0.01	0.05	0.00	10	NA
800436	LAR	4	3/28/14	1:40:00	3/28/14	1:42:00	--	--	2	0.200	5	664	5	22.0	0.00	0.01	0.01	0.05	0.00	10	NA
800436	LAR	4	3/28/14	3:47:00	3/28/14	3:49:00	--	--	2	0.307	5	738	5	23.0	0.01	0.02	0.01	0.08	0.00	10	NA
800436	LAR	4	3/28/14	4:26:00	3/28/14	4:27:00	--	--	2	0.129	5	748	5	23.0	0.00	0.01	0.01	0.04	0.00	10	NA
800436	LAR																				

South Coast Air Quality Management District

Tesoro Refinery Carson (formerly BP Carson)
2014 Rule 1118 Quarterly Flare Emissions

Emission Target

2014 SOx Emissions Target (lbs)	Year-to-date SOx Emissions (lbs)
95,160	736.0

Quarter I (January 1, 2014 - March 31, 2014):

Flare ID	Total Gas Flow (scf)	Emissions (lbs)				
		PM-10	NOx	ROG	CO	S as SO2
5 Flare	21,941,933	164.6	2,852.5	153.6	768.0	18.2
FFHDS	4,373,765	32.8	568.6	30.6	153.2	3.6
HC	12,722,514	95.6	1,653.2	90.0	450.9	10.5
FCC	10,552,662	79.3	1,370.6	74.6	373.5	8.9
Coker	8,525,838	64.5	1,107.2	62.9	317.3	9.4
Total	58,116,712	436.8	7,552.1	411.7	2,062.9	50.6

Quarter II (April 1, 2014 - June 30, 2014):

Flare ID	Total Gas Flow (scf)	Emissions (lbs)				
		PM-10	NOx	ROG	CO	S as SO2
5 Flare	27,045,695	203.2	3,513.8	190.6	954.2	22.6
FFHDS	4,666,754	35.0	606.5	32.8	164.3	3.9
HC	13,801,552	103.6	1,793.8	97.0	485.3	11.5
FCC	10,872,927	81.7	1,412.6	76.8	384.7	9.0
Coker	8,865,051	67.9	1,143.2	65.6	331.5	15.9
Total	65,251,979	491.4	8,469.9	462.8	2,320.0	62.9

Quarter III (July 1, 2014 - September 30, 2014):

Flare ID	Total Gas Flow (scf)	Emissions (lbs)				
		PM-10	NOx	ROG	CO	S as SO2
5 Flare	32,451,379	243.4	4,218.7	227.2	1,135.8	26.9
FFHDS	4,696,917	35.2	610.6	32.9	164.4	3.9
HC	24,093,449	314.7	2,159.0	393.3	2,223.4	392.4
FCC	10,465,327	79.5	1,360.8	82.3	419.6	20.8
Coker	8,970,585	67.7	1164.8	64.8	326.1	7.8
Total	80,677,657	740.5	9,513.9	800.5	4,269.3	451.8

Quarter IV (October 1, 2014 - December 31, 2014):

Flare ID	Total Gas Flow (scf)	Emissions (lbs)				
		PM-10	NOx	ROG	CO	S as SO2
5 Flare	35,438,402	266.2	4,605.70	250.20	1,253.10	29.5
FFHDS	6,876,614	82	715.1	138	782.2	10
HC	15,578,895	117	2,024.80	109.6	548.7	12.9
FCC	7,745,399	59.8	997.50	60.2	307.2	7.1
Coker	9,344,480	77.5	1,174.10	89.9	474.3	111.2
Total	74,983,790	602.50	9,517.20	647.90	3,365.50	170.7

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Industrial Flares: Linking Plume Dispersion with Combustion

Paper AT-4a #6

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ABSTRACT

Flares are used in many industries as air emission control devices to combust flammable and toxic or odorous vapors. A flare can be a cost-effective device for destroying both episodic and routine emissions. A well-designed and operated flare has a high destruction efficiency that results in good plume rise with low pollutant concentrations at ground level. However, operational factors, such as low heat content, high or low exit velocity, and high wind speed can significantly reduce the flare efficiency. Wind tunnel experiments by Johnson [1] show that a low exit velocity makes flames susceptible to wind effects and reduces the flare efficiency. This reduction in efficiency has three significant concerns: a) flame height is reduced, b) buoyant plume rise is reduced, and c) pollutant concentration is increased in the plume.

Although a high wind speed may reduce the flare efficiency, it also enhances plume dispersion. The plume dispersion analysis must be linked with combustion to determine if a reduction in flare efficiency will cause high pollutant concentrations. It is important to have a dispersion model that can be used to demonstrate that workers and the public are adequately protected from high ambient concentrations in the event of a process upset. Most common air dispersion models, such as the EPA SCREEN3 and ISCST3, do not explicitly consider flare efficiency or link plume dispersion with combustion.

This paper presents an experimental model for evaluating the reduction in flare efficiency that may occur due to a high wind speed. Guidance is presented on how to optimize the calculations to identify operating scenarios and meteorological conditions that may cause high ambient concentrations. An example dispersion study is presented.

BACKGROUND

An industrial flare is simply described as a device that destroys waste gases by combusting them in the atmosphere, usually at the top of an elevated stack as shown in Figure 1. Waste gases are injected into the open air through the flare tip that is designed to promote air entrainment and maintain a stable flame [2]. If the waste gas has insufficient heating value to maintain a stable flame, then fuel gas is added. A pilot light ensures that the flame stays lit. A major concern is the potential exposure of people and equipment to thermal radiation from the flame. Maximum radiation levels are calculated and incorporated into the flare design. Another concern is the potential exposure to toxic chemicals or odors in the flare plume; so ambient concentrations are predicted and evaluated. This topic is discussed in detail later.

WHY AN ACCURATE FLARE DISPERSION ANALYSIS IS IMPORTANT

During the design phase, a flare will typically be evaluated using the maximum load. The maximum load has the greatest need for safe operation since it has the maximum radiation level and maximum pollutant emission rate. However, the maximum load will reflect optimum dispersion due to maximum plume rise and exit velocity. Low load scenarios should also be considered, because these may cause higher ambient concentrations at ground level.

The reduction in flare efficiency due to wind effects is a significant issue. Since pollutant emission depends on the flare efficiency, a relatively small change in efficiency from 98% to 96%, may double the predicted ambient concentrations. This efficiency reduction may explain why a flare that is rated as 98% efficient may cause an occasional odor problem.

MODELING PLUME DISPERSION

Ambient concentrations from a flare are commonly predicted using a Gaussian equation. For a screening analysis, the standard Gaussian model can be used if it has buoyant plume rise and buoyancy induced dispersion algorithms. These additional algorithms are required for a refined analysis; gradual and final buoyant plume rise; flame length and flame distortion due to wind; radiant heat loss from plume to atmosphere, and flare efficiency.

The experimental model, CARNIVOR2, takes a simple, first step in linking combustion efficiency with air dispersion modeling. Experimental results from Johnson [1] were used to estimate flare efficiency as a function of exit velocity and wind speed. The pollutant emission rate, flame length, and buoyant plume rise are calculated using the flare efficiency. The user can either input a single atmospheric stability and wind speed or allow the model to iterate through 53 combinations of atmospheric stability and wind speed to predict the maximum concentration. Details of the important algorithms are discussed below.

Plume Rise

Figure 1 illustrates an industrial flare and some of the important dispersion parameters. Plume rise is quite important because ground level concentrations decrease as plume height increases. **Equation 1.** The effective plume height, h_{eff} (m), in the Gaussian equation is shown below.

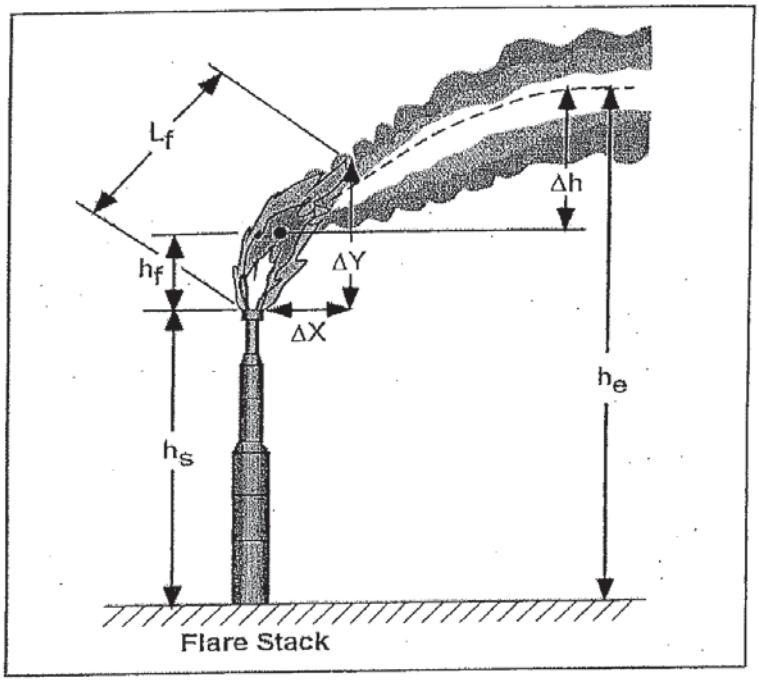
$h_{eff} = h_s + h_f + \Delta h$
h_s = stack height (m)
h_f = flame height (m)
Δh = plume rise (m)

It must first be determined if plume rise is dominated by momentum or buoyancy[3]. The buoyant equations estimate plume rise for hot combustion gases. The momentum equations estimate plume rise when the exit velocity is high and the plume temperature is near ambient, such as a flame out scenario. The Briggs equations are the most popular plume rise equations and are based on observations of plumes from large power plants. EPA used Briggs equations in the ISC[3] and SCREEN3 dispersion models[4].

If a plume has not attained its maximum height (final plume rise) then gradual plume rise

nations should be used. Gradual plume rise is important for a buoyant plume because it will slower than a momentum plume and disperse farther downwind to attaining its final height.

Figure 1. An industrial flare illustrating some of the important dispersion parameters.



Flare Buoyant Plume Rise

The buoyancy flux calculation for a flare is slightly different than the calculation for a stack. Equation 2. Schultz[5] calculates the buoyancy flux, F_b (m^4/s^3), for a flare below.

F_b = $(g * Q_c) * (1 - R) / (\pi * \rho_a * C_p * T_a)$
g = gravitational acceleration (9.8 m/s^2)
Q_c = heat release rate (cal/s)
R = fraction of heat loss due to radiation
ρ_a = ambient air density (g/m^3)
C_p = specific heat of air (0.24 cal/g/°K)
T_a = ambient temperature (°K)

Equation 3. The buoyancy flux, $F_b(m^4/s^3)$, for a stack, is calculated below[3].

$F_b = (g * V_s * d_s * d_s)(T_s - T_a) / (4*T_s)$

V_s = stack exit velocity (m/s)

d_s = stack diameter (m)

T_s = stack temperature (°K)

After buoyancy flux is calculated, both the flare and stack use the same buoyant plume rise formulas described in Section 1.1.4 of the User's Guide for the ISC Dispersion Models[3].

A second method requires extra calculation steps, so that a flare can be modeled as a stack simultaneously with other sources. One must first calculate F_b using Equation 2. One then assumes $V_s = 20$ m/s, $T_s = 1273$ °K (these are typical values within the normal operating range); and back calculates an effective stack diameter from Equation 3. The stack height may be modified to account for the flame height. The velocity, temperature, and diameter values are used in the dispersion model for a stack release option. The plume rise results are comparable to the first method.

Radiant Heat Loss from Flame to Atmosphere

The infrared radiation from the flare flame is important because heat loss will reduce the plume rise. The buoyancy flux is directly proportional to the sensible heat, (1– R in Equation 2). The plume rise decreases as radiant heat loss increases. Shore [6] developed a technique to estimate heat loss (i.e. emissivity). He reported values for R ranging from 0.15 for Methanol to 0.4 for Benzene and Ethylene. Radiant heat loss is site-specific; it depends on the fuel, flame size, temperature, and soot formation. For example, a flame with a large amount of suspended carbon (smoke) will have more radiant heat loss than a clean flame [6]. If the R value is unknown, then it is conservative to use a large R value, since this reduces the plume rise and increases the predicted concentrations. The EPA SCREEN3 model assumes the R value is 0.55.

Flame Length and Distortion Due to Wind

Flame height is also required to determine the effective plume height, as shown in Equation 1. There are several flame height equations in use [4,6,7]. The equations define flame length as a function of the heat release rate raised to a power. Kumar [7] presented the American Petroleum Institute (API) Recommended Practice 521 equations for estimating flame length, L_f, and wind distorted flame height, Δy, as shown in Figure 1. The wind distorted flame height is based on flame length, exit velocity, and wind speed. Since the flame length fluctuates rapidly, some dispersion modelers conservatively use 50% of L_f. This represents the flame "center"; it can vary from the apparent visual center [6].

Flare Efficiency

The combustion process is important because it initializes many of the air dispersion model parameters. A decrease in flare efficiency increases the pollutant emission rate while decreasing the flame height and buoyant plume rise. All these factors result in higher ground level concentrations. The converse is also true; as flare efficiency increases, then ground level concentrations will decrease.

Wind tunnel experiments performed by Johnson [1] show that a low flare exit velocity coupled with high wind speed may result in a reduced destruction efficiency. These experiments used small flames with small heat release rates, so the lab experiments may be more susceptible to the wind than full scale flames. The experimental results may uuder predict combustion efficiency when extrapolated to a larger flame [8].

Equation 4. The preliminary experimental results [9] for natural gas fit best to a quadratic equation to calculate combustion inefficiency.The combustion inefficiency, Y (%), is calculated as a function of exit velocity and of wind speed.

$Y = 0.1127–0.814*X + 0.173*X^2$
$X = u/ V_s^{0.333}$
u = wind speed (m/s)
V_s = flare exit velocity (m/s)

Equation 5. The preliminary results from the propane experiments [9] fit best to a cubic equation.

$Y = -14.4+6.14*X - 0.846*X^2 + 0.038*X^3$

Equation 6. Combustion efficiency, C_e (%), is calculated below.

$C_e = (100-Y)$

Johnson [1] attributed the higher combustion efficiency for propane to its higher energy density. The combustion inefficiency equations do not apply to a flare that has its flame enclosed in a shroud; the flame is not exposed to the wind. The calculated combustion efficiency can be greater than the design efficiency (typically 98%), so logic must be included in the model code to prevent this.

A point of clarification is that hydrocarbon destruction efficiency considers the fraction of hydrocarbons in the waste gas that is destroyed by combustion. Combustion efficiency considers the fraction of hydrocarbons that is completely converted to carbon dioxide and water. The hydrocarbon destruction efficiency may be higher than the combustion efficiency. Hydrocarbons in the waste gas may be destroyed but not be completely converted to carbon dioxide; carbon monoxide and other carbon containing combustion by-products may be formed. The bulk of the incompletely combusted material will be carbon monoxide, as it is the most stable combustion intermediate[10].

FLARE REGULATIONS

Flares may be subject to air emission regulations, such as the Maximum Achievable Control Technology (MACT) rules. The General Provisions 40CFR63.11(b) set upper limits for the flare tip exit velocity ranging from 18.3 to 122 m/s, depending on the flare design. The velocity limit prevents flame blowout or flame lift-off from the tip with subsequent escape of uncombusted vapors. These regulations do not set lower limits for exit velocity. Setting a lower limit for exit velocity is impractical because the flow rate (and exit velocity) can be highly variable. Many flares used for batch unit operations are in a standby mode waiting to receive waste gases [6]. These flares are usually continuously purged at a very low rate until they go into service.

Flares used to destroy episodic emissions may not be covered by air emission regulations; these follow good design practice. These flares also have highly variable flow rates (and exit

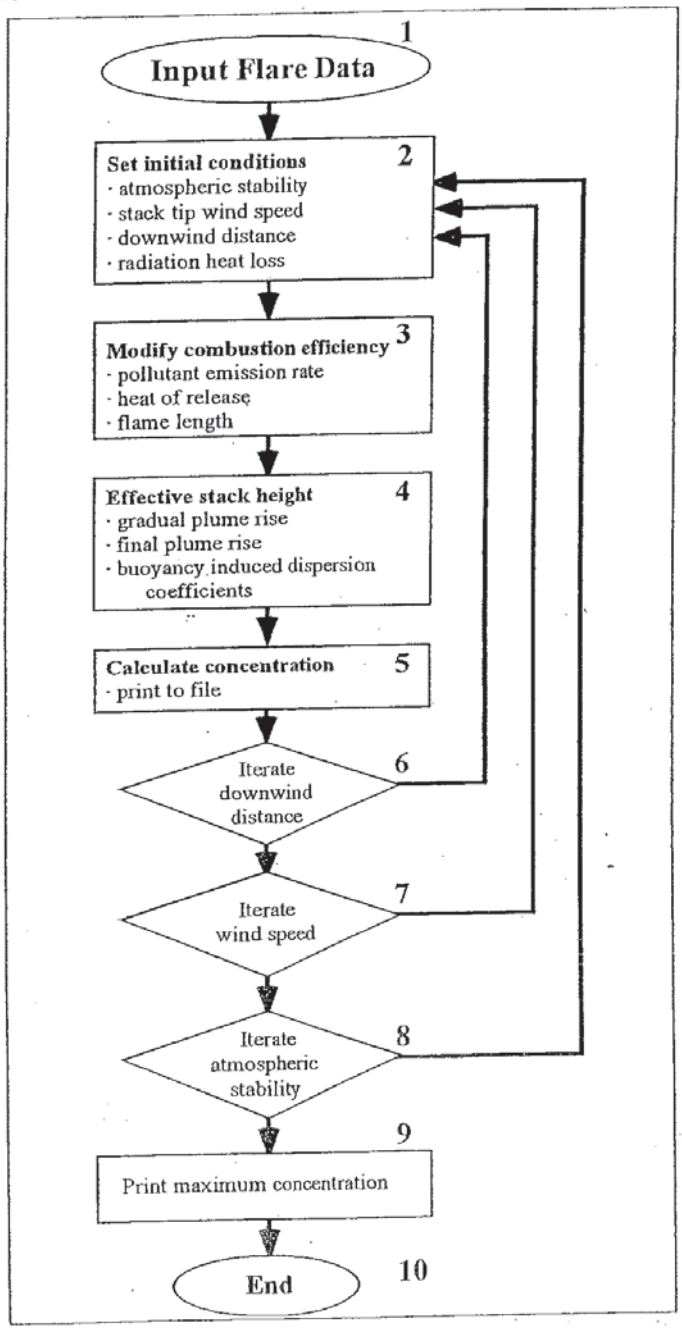
velocities). Episodic events occur infrequently. When an such an event does occur, the flow rate may increase from zero to a high value and then back down to zero within a few minutes.

OPTIMIZING DISPERSION CALCULATIONS

If a flare has the potential to cause high ambient concentrations/odors, the conditions that may cause a problem should be identifiable using a dispersion analysis. Although a high wind speed may reduce flare efficiency, it also enhances plume dispersion. The CARNIVOR2 model optimizes the dispersion calculations by iterating though 53 combinations of atmospheric stability and wind speed in a single model run. If a high wind speed reduces the flare efficiency, then the model adjusts other parameters, such as pollutant emission rate, flame length, and buoyant plume rise. The model identifies the maximum concentration and its associated atmospheric conditions. Figure 2 shows a simple logic flowchart with the major model components.

- Block 1; input data on flare characteristics.
- Block 2; calculations to initialize model.
- Block 3; calculate combustion efficiency.
- Block 4; calculate effective stack height.
- Block 5; calculate plume concentration.
- Blocks 6, 7, and 8; iterate downwind distance, wind speed, and atmospheric stability.
- Block 9; determine maximum concentration and associated meteorological conditions.

ure 2. A simple logic flowchart for linking combustion and air dispersion showing the major
el components.



AWMA 2001, Orlando

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FLARE PLUME DISPERSION EXAMPLE

The CARNIVOR2 model was used to predict flare efficiencies, plume rise, and ambient concentrations for the following example. The hypothetical flare is sized to control emissions from emergency pressure relief of the reactor, an infrequent event. However, it routinely receives emissions from batch unit operations (reactor emptying, tank filling, etc.) that vary from 3% to 15% of the maximum load. Table 1 presents data for various load conditions. It receives a Hydrocarbon [3] in a nitrogen purge stream. Supplemental fuel gas is used to maintain the heat content at 7.5 MJ/m^3, the minimum for a nonassisted flare. Model predictions are presented below and compared to results obtained from the EPA SCREEN3 model. Rural dispersion coefficients were used in both cases.

The Hydrocarbon being burned has an odor threshold of 10 µg/m^3; which is quite low. The Hydrocarbon has an Emergency Response Planning Guideline (ERPG–1) value of 229 µg/m^3; this is the maximum airborne concentration below which it is believed that all individuals could be exposed for up to one hour without experiencing other than mild transient adverse health effects or perceiving a clearly defined objectionable odor.

Table 1. Flare operating data for various load conditions.

Scenario load (%)	100	15	10	5	3
Total mass rate to flare, including inerts (kg/hr)	4,091	614	409	205	123
Hydrocarbon rate to flare (g/s)	226.8	34.0	22.7	11.3	6.8
Flare exit velocity (m/s)	60	9	6	3	1.8
Heat release rate (cal/s)	1,636,614	245,492	163,661	81,831	49,098
Rated combustion efficiency (%)	98	98	98	98	98
Flare stack height (m)	12.2	12.2	12.2	12.2	12.2
Ambient temperature (K)	298	298	298	298	298

Dispersion Results

Figure 3 presents the predicted flare destruction efficiency as a function of flare tip exit velocity (V_s) and wind speed. For this example, the flare efficiency remains at the rated 98% until the wind speed approaches 8 m/s; then the efficiency for exit velocity of 1.8 m/s decreases dramatically to 82% for a 15 m/s wind speed. The efficiencies for exit velocities of 3, 6, and 9 m/s, decrease to 89%, 94%, and 96.3%, respectively, for the 15 m/s wind speed. It is not shown in the figure but for flare exit velocities greater than 9 m/s, the flare efficiency is not reduced by wind speed. The SCREEN3 model does not consider flare efficiency or exit velocity, so its results are not shown in the figure.

Figure 3. The predicted flare destruction efficiency (%) as a function of flare tip exit velocity (V_s in m/s) and wind speed (m/s). The radiant heat loss is 0.40 and the stability is class "D".

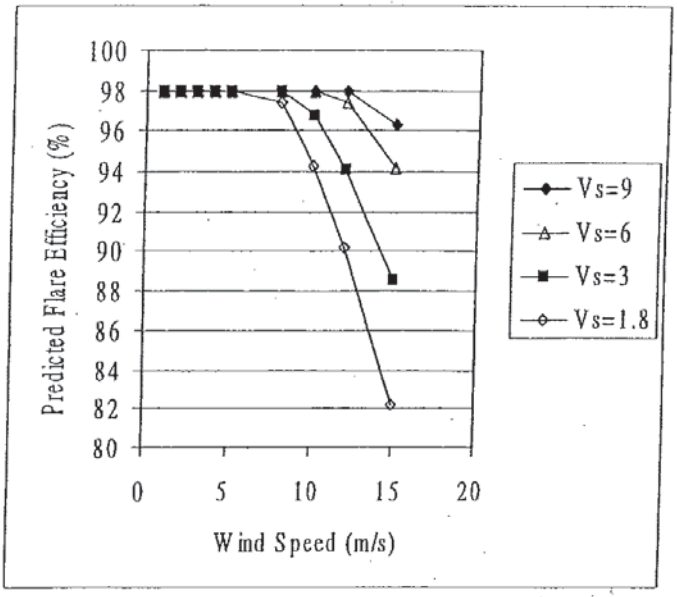


Figure 4 presents a sensitivity analysis for radiant heat loss, R. Plume rise versus downwind distance is presented for radiant heat loss values of 0.20, 0.40, 0.55 for a wind speed of 2 m/s. The predicted plume rise increases as the heat loss decreases. The final plume height occurs about 100 meters downwind. There is a significant difference in plume rise (and concentrations) at low wind speeds. Figure 4 shows SCREEN3 plume rise is constant with downwind distance because this model always uses the final plume height.

Figure 4. The predicted plume rise versus downwind distance for three values of radiant heat loss, R. The wind speed is 2 m/s, exit velocity is 6 m/s, stability is class "D", and load is 10%.

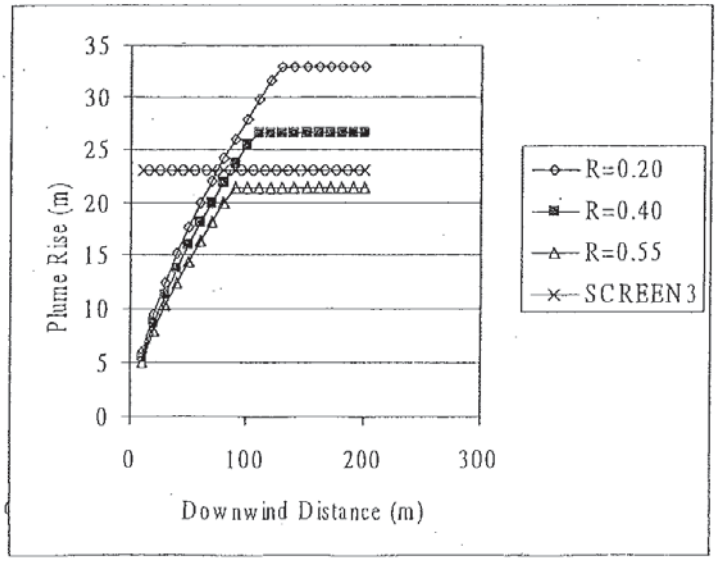
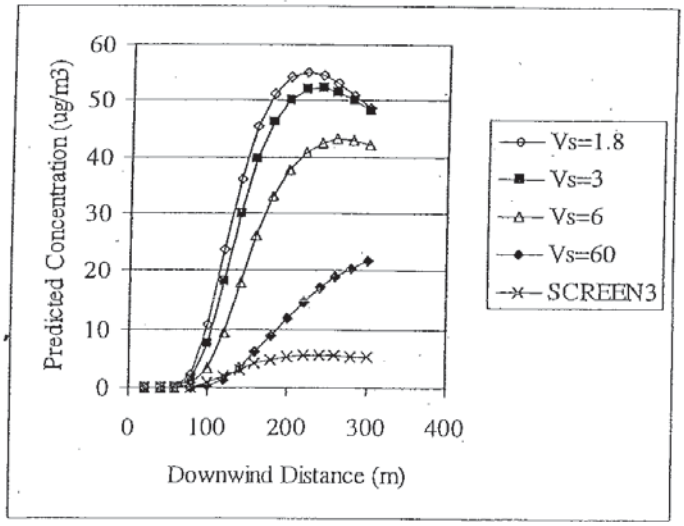


Figure 5 presents ground level concentrations as a function of flare tip exit velocity (V_s) for the worst case atmospheric condition, a 15 m/s wind speed. As shown in Table 1, the flare tip exit velocities of 1.8, 3, 6, and 60 m/s correspond to loads of 3, 5, 10, and 100%. The predicted concentrations for the lowest exit velocity of 1.8 m/s at 3% load are significantly higher, because these conditions have the efficiency reduced to 82%. For exit velocities of 3, 6, and 60 m/s, the efficiencies are higher (89%, 94%, and 98%, respectively). The predicted concentrations were lower because plume rise was greater even though the emission rates were higher. Figure 5 also shows that low load conditions result in higher predicted concentrations than the maximum load conditions (exit velocity of 60 m/s). For the same conditions (3% load or exit velocity of 1.8 m/s), SCREEN3 model predicted much lower concentrations than CARNIVOR2, because SCREEN3 did not reduce the flare efficiency. CARNIVOR2 showed there is potential for an odor problem because the predicted concentrations are greater than the 10 $\mu g/m^3$ odor threshold. Fortunately, a 15 m/s wind speed is an infrequent event but it illustrates how high wind speed may cause an odor problem. The predicted concentrations are well below the ERPG–1 value of 229 $\mu g/m^3$; one would not anticipate adverse health effects.

Figure 5. The predicted ground level concentrations on plume centerline versus downwind distance for several flare exit velocities. The radiant heat loss fraction is 0.40, wind speed is 15 m/s, and atmospheric stability is class "D".



DISCUSSION

This experimental dispersion model can be used to demonstrate that workers and the public are adequately protected from high ambient concentrations in the event of a process upset. There can be significant differences in predicted concentrations for various load scenarios.

- Low load conditions are more susceptible to a destruction efficiency reduction during a high wind, as shown in Figure 3.
- Low load scenarios should be evaluated because these may result in higher concentrations than the maximum load scenario, as shown in Figure 5.
- For different radiant heat loss factors, there is a difference in plume rise (and concentration) for a low wind speed, as shown in Figure 4. However, the difference in plume rise decreases with increasing wind speed.
- Flame height is reduced as wind speed increases. The maximum reduction in flare efficiency occurs during a high wind when the flame is at its minimum height.

This model provides a satisfactory level of accuracy for most engineering applications. It has the all the limitations associated with a Gaussian dispersion model. Many flare parameters, such as flame length, plume rise, heat loss, and destruction efficiency, must be calculated because they can not be easily measured.

For a flare with a variable flow rate, the duration of the low exit velocity is important. If a high concentration occurs for a brief period, an odor may not be noticed. The model has a concentration averaging time on the order of 15 to 60 minutes. One may convert the model predicted concentrations to a shorter averaging time (with a higher concentration) for odor episodes.

If a flare causes an odor problem at low load conditions during high winds, a simple fix may be to increase the purge gas flow rate. If the resultant heating value is too low, then the fuel gas flow rate must also be increased. A long-term solution may require installation of a smaller flare tip, a staged flare, or use a shroud to enclose the flame [8].

This model is the first step in linking plume dispersion with flare combustion. The next and more complicated step is to consider the effect of the heat release rate on the combustion efficiency. This may be the subject of a future paper.

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Key Word Index: industrial flare, air dispersion modeling, combustion efficiency, plume rise.

Theoretical and observational assessments of flare efficiencies. - PubMed

Author information

Abstract

Flaring of waste gases is a common practice in the processing of hydrocarbon (HC) materials. It is assumed that flaring achieves complete combustion with relatively innocuous byproducts such as CO2 and H2O. However, flaring is rarely successful in the attainment of complete combustion, because entrainment of air into the region of combusting gases restricts flame sizes to less than optimum values. The resulting flames are too small to dissipate the amount of heat associated with 100% combustion efficiency. Equations were employed to estimate flame lengths, areas, and volumes as functions of flare stack exit velocity, stoichiometric mixing ratio, and wind speed. Heats released as part of the combustion process were then estimated from a knowledge of the flame dimensions together with an assumed flame temperature of 1200 K. Combustion efficiencies were subsequently obtained by taking the ratio of estimated actual heat release values to those associated with 100% complete combustion. Results of the calculations showed that combustion efficiencies decreased rapidly as wind speed increased from 1 to 6 m/sec. As wind speeds increased beyond 6 m/sec, combustion efficiencies tended to level off at values between 10 and 15%. Propane and ethane tend to burn more efficiently than do methane or hydrogen sulfide because of their lower stoichiometric mixing ratios. Results of theoretical predictions were compared to nine values of local combustion efficiencies obtained as part of an observational study into flaring activity conducted by the Alberta Research Council (ARC). All values were obtained during wind speed conditions of less than 4 m/sec. There was generally good agreement between predicted and observed values. The mean

Impacts of Emission Variability and Flare Combustion Efficiency on Ozone Formation in the Houston–Galveston–Brazoria Area

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This article is part of the Industrial Flares special issue.

Abstract

Recent studies in the Houston–Galveston–Brazoria (HGB) area of Texas have suggested that industrial flares exhibit high temporal emissions variability and that flare combustion efficiencies could vary with air and steam assist rates, particularly at lower flow rates, and when low heating value gases are combusted. This work examined the difference in ozone formation potential associated with accounting for temporal variability in flaring emissions, as opposed to assuming the same amount of mass was emitted at a constant, average flow rate. The temporal variability in flare emissions was found to lead to differences in ozone concentrations of as much as 27 ppb in the HGB area. This work also examined the potential ozone formation impacts of flare combustion efficiencies of less than 98–99%, applied to 25 flares throughout the HGB region. Deterioration in combustion efficiency (CE) was found to affect ozone concentrations by a few to more than 50 ppb, depending on the level of the assumed CE. While the ozone impacts associated with temporal variability in emissions typically lasted a few hours, consistent with the length of large flaring events, lowering of the CE significantly increased emissions and ozone concentrations over periods ranging from several hours to several days for some flare types. Thus, changes in CE may affect ozone concentrations for longer durations and over larger spatial extents than episodic emissions events.

Process Diagram « John Zink Hamworthy Combustion

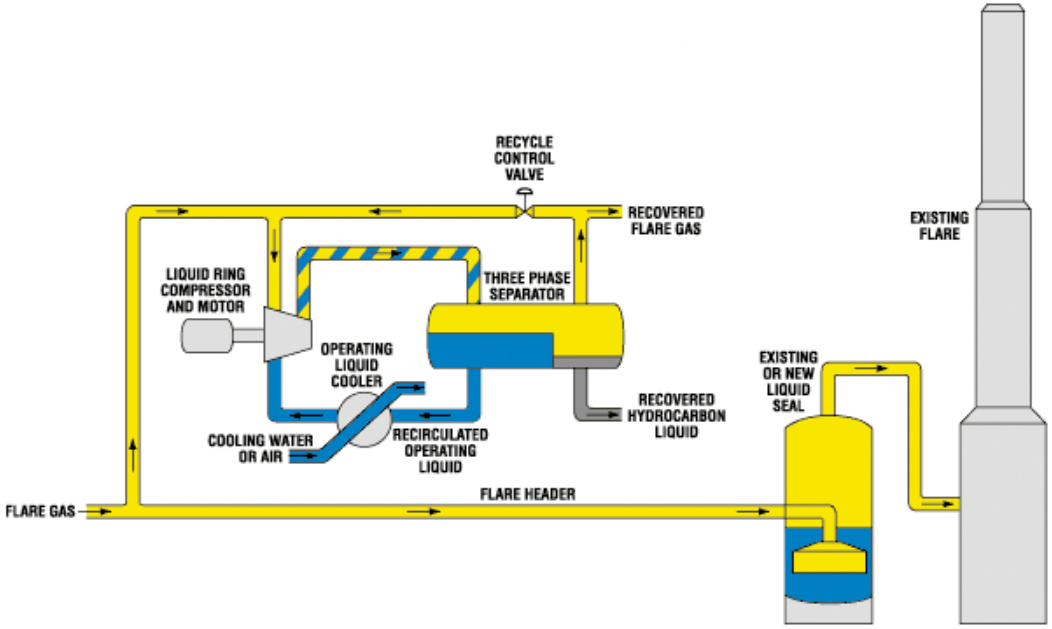
Process Diagram

John Zink Hamworthy Combustion Flare Gas Recovery Unit

Our recovery process is incorporated with your flare system to safeguard company personnel and the environment. The following process diagram demonstrates the integration and function of a John Zink Hamworthy Combustion flare gas recovery system with an operating flare process.

John Zink Hamworthy Combustion's experienced team of skillful engineers will thoroughly evaluate your flare system, process conditions and project goals, and select the compressor technology that is best-suited for your specific application.

- Liquid Ring (shown below)
- Reciprocating
- Screw
- Sliding vane



A flare system consists of a vapor header that collects the flare gases from various sources, a knockout vessel, a liquid seal vessel, and the flare itself. The flare gas recovery unit connection is typically located between the knockout vessel and the liquid seal. Any liquids in the flare gas should be removed before introduction into the flare gas recovery unit. The primary control variable of the John Zink Hamworthy Combustion flare gas recovery unit is flare system header pressure.

As the flare header pressure reaches the predetermined pressure control set point, a liquid ring compressor starts up and begins to compress the flare gas. The compressor uses an operating liquid, usually water, to perform the work of compression on the recovered gas. The operating liquid is cooled in a shell-and-tube heat exchanger, evaporative cooler or air-cooled heat exchanger to control compressor discharge temperature.

The compressor discharges the gas into a three-phase separator that separates the operating liquid from the flare gas and then the condensed hydrocarbons from the operating liquid. Instead of venting process vent streams into the flare system, the compressed gases are made available to the operating plant’s fuel gas supply or possibly as a process feedstock.

Integration and control of a flare gas recovery unit is of critical importance. For example, care must be exercised in the design of the recovery system to prevent application of a vacuum to the vapor header that might draw in air and create a flammable mixture in either the flare header or the fuel gas system.

When all compressors are operating at full capacity and if the process vent flow rate continues to increase, flare gas will begin to pass through the liquid seal and flow to the flare stack. Therefore, the safety function of the flare system is maintained in the event of process upset conditions.

To discuss a customized solution for your operation, contact John Zink Hamworthy Combustion's flare gas recovery group.

Flare Gas Recovery - It's more than just a Compressor Skid™

Excerpts, full report available at:
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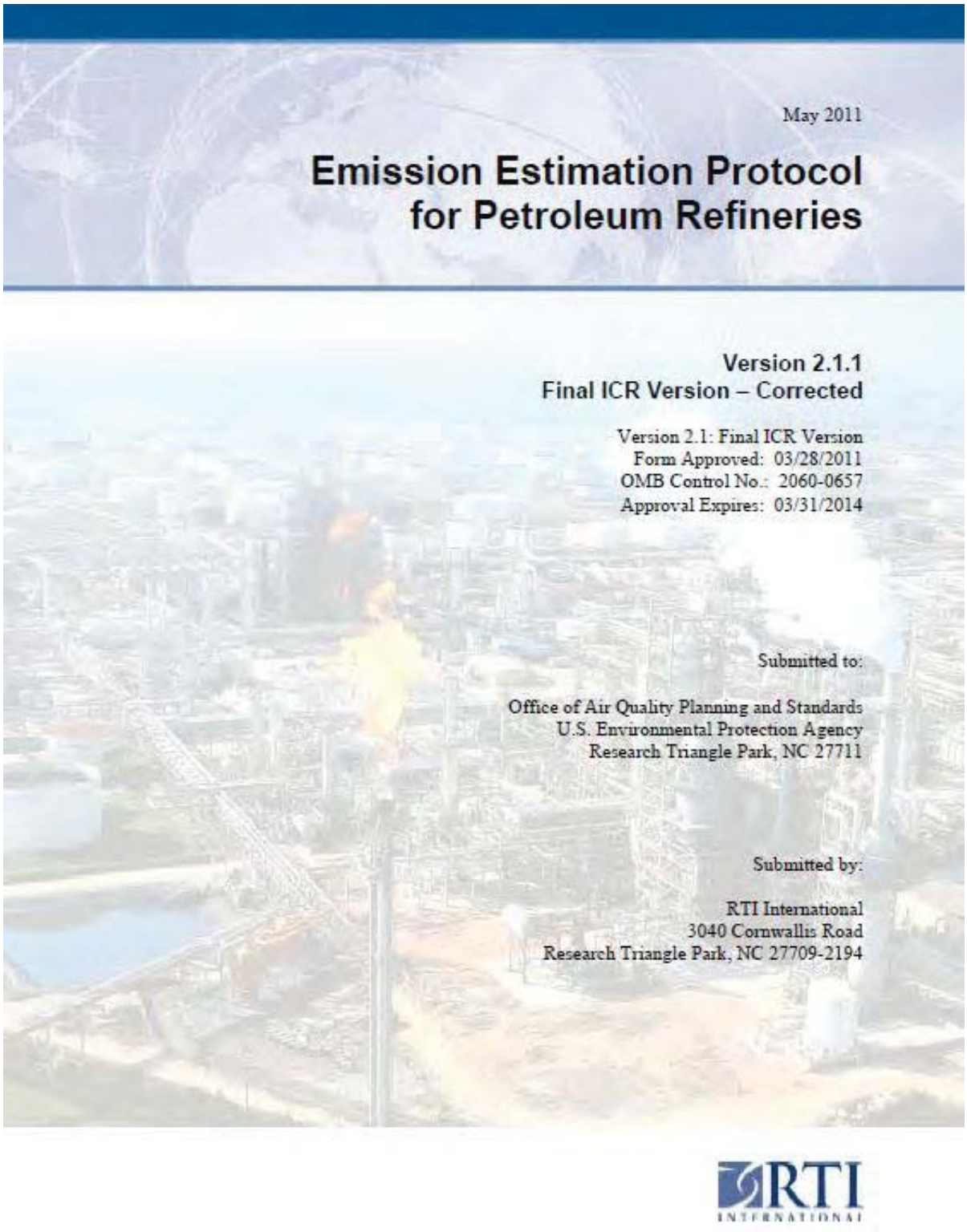

May 2011

Emission Estimation Protocol for Petroleum Refineries

Version 2.1.1
Final ICR Version – Corrected

Version 2.1: Final ICR Version
Form Approved: 03/28/2011
OMB Control No.: 2060-0657
Approval Expires: 03/31/2014

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Research Triangle Park, NC 27711

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RTI International
3040 Cornwallis Road
Research Triangle Park, NC 27709-2194

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5.5 Sulfur Recovery Plants

All crude oils contain some sulfur compound impurities. Sulfur compounds in crude oil are converted to H_2S in the cracking and hydrotreating processes of the refinery. The H_2S in the generated gas streams is removed from the process vapors using amine scrubbers. The amine scrubbing solution is subsequently heated to release the H_2S to form an H_2S rich "acid gas" that is treated in the sulfur recovery plant to yield high-purity sulfur that is then sold as product. Most sulfur recovery plants use the Claus reaction and are commonly referred to as Claus units or Claus sulfur recovery plants. There are a couple of other types of sulfur recovery plants at smaller refineries, but all larger sulfur recovery plants employ Claus units. The exhaust gas from the sulfur recovery unit (SRU) is commonly referred to as "tail gas." The sulfur recovery plant consists of one or more SRU operated in parallel and may also contain one or more catalytic tail gas treatment units and/or a thermal oxidizer to combust the tail gas.

The primary HAP components of the final sulfur plant vent are carbonyl sulfide (COS) and carbon disulfide (CS_2). These HAP components are by-products of the SRU and tail gas treatment unit (TGTU) reactions; COS may also be a product of incomplete combustion from a thermal oxidizer. Unreacted H_2S may also be released during the process. Sulfur recovery plant vents are commonly controlled by a thermal oxider to oxidize unreacted H_2S or H_2S in sweep gas from the sulfur pits to SO_2. Some sulfur recovery plants use reducing controls and thus emit H_2S rather than SO_2. The sulfur plant sour gas feed may also contain small amounts of light organics. Therefore, it is important to account for the hydrocarbons in the sulfur recovery plant feed when estimating emissions from the sulfur recovery plant, particularly from Lo-Cat® or other sulfur recovery plants that may have atmospheric vents without thermal destruction.

When the sulfur recovery plant is in operation, the sulfur plant vent flow rate is fairly small so that the SO_2 emissions from the sulfur recovery plant are also relatively small. If the sulfur recovery plant must be taken offline due to an upset or malfunction, the sour gas may be temporarily directed to a backup sulfur recovery unit or directed to a flare or the thermal oxidizer. If the sour gas in these cases is sent to a flare or thermal oxidizer, the SO_2 emissions can be very large. As such, it is critical to include accurate accounting of SO_2 emissions during startup, shutdown, or malfunction (SSM) events associated with the sulfur recovery plant.

5.5.1 Methodology Ranks 1 and 2 for Sulfur Recovery Plants

It is anticipated that most sulfur recovery plants, particularly Claus sulfur recovery plants, will have continuous SO_2 concentration monitors. When continuous flow monitors are also in place, mass emissions rates can be calculated using the CEMS method previously described in Section 4, *Stationary Combustion Sources*. Unlike combustion sources, however, there is not an F factor method to project the vent flow rate. If the flow rate and H_2S concentration of the feed to the sulfur recovery plant, the air or oxygen feed rates to the sulfur plant burner (used to convert one-third of the H_2S to SO_2), and the quantity of sulfur recovered are known, then calculations to determine/quantify emissions can be made, but the calculations are not trivial. As such, there is not a simple Rank 2 method that can be provided for sulfur recovery plants. Non-Claus sulfur recovery plants may monitor H_2S or reduced sulfur compound concentrations instead of SO_2. Again, H_2S emissions estimates should be provided for sulfur recovery plants.

5.5.2 Methodology Ranks 3 and 4 for Sulfur Recovery Plants

Emissions estimates can be made from inlet flow measurements and assumed recovery efficiencies. For most Claus units, especially those with tail gas treatment/recovery units, a mass balance approach for sulfur is expected to yield emissions estimates with high uncertainties (e.g., when two large numbers are subtracted so that the difference is only a few percentages of the original values, the uncertainties in the original values may be as large as the difference). A three-stage Claus unit is expected to have sulfur

6. Flares

Flares are point sources used at petroleum refineries to destroy organic compounds in excess refinery fuel gas, purged products, or waste gases released during startups, shutdowns, and malfunctions. Most flares have a natural gas pilot flame and use the fuel value of the gas routed to the flare to sustain combustion. If the heating value of the flare gas falls below certain values (for steam or air assisted flares, typically 300 British thermal units per standard cubic feet [Btu/scf]), then natural gas may be added to the flare gas to maintain the appropriate heating value for good combustion. Emissions from flares consist of a fraction of the hydrocarbons in the flare gas (e.g., CH_4, CO, VOC, and specific organic HAP) that are not combusted in the flare; SO_2 resulting from the oxidation of sulfur compound impurities, such as H_2S, in the gas stream; and CO_2 from the combustion process. Flares are also expected to produce NO_x emissions and may produce PM (soot) if combustion conditions are not adequate. A complete emissions inventory will include estimates for all these compounds (the specific organic HAP will vary based on the composition of the gas being flared).

Accurate estimates of emissions from flares are difficult to obtain because they do not lend themselves to conventional emissions-testing techniques, and only a few attempts have been made to characterize flare emissions. Therefore, to date, there are limited direct emissions test data for flares. Recent developments in testing protocols, such as the DIAL technique, provide a direct emissions measurement technique for flares. However, DIAL measurements provide only a snapshot in time. Unless the flow and composition of the flare gas is highly stable, inaccuracies build as these measurements are extrapolated to annual emission rates. Continuous monitoring of the gas stream prior to combustion in the flare is generally the most accurate means of assessing flare emissions. One difficulty with this approach is that flare gas composition and flow are highly variable, and the monitors are calibrated to detect compositions or flows within a certain range or span, so if the flow or composition is outside the instrument's range, then inaccuracies in the measurement data result. In addition, because the monitors are evaluating the stream of gas going to the flare, assumptions must be made regarding flare efficiency to determine the emissions following combustion. Engineering calculations are another methodology that can be used to assess certain release events. For example, if a pressure relief valve on a tank opens, then the volume of gas released can be calculated based on the pressure inside the tank, the pressure outside the tank, the cross-sectional area of the valve opening, and the duration the valve is open (see Section 12, *Malfunctions/Upsets*, in this Refinery Emissions Protocol document. Product knowledge of the tank liquid composition can be used to calculate the equilibrium vapor space composition, which is assumed to be the composition of the gas vented. Some emission factors are available, but these have high uncertainty. EPA concludes that direct measurement methods are best used to develop site- or flare-specific emission factors or to verify the combustion efficiency of a specific flare under certain conditions; however, they are not particularly useful in developing an emissions inventory for flares.

Table 6-1 summarizes the hierarchy of flare emissions estimation techniques. Within a given measurement method (or rank), there may be alternative methods for determining the constituent-specific emissions; these compositional analysis methods are provided in order of accuracy. Each refinery will likely use a mixture of different methods. For example, Methodology Rank 1 for flares may be used for events that are directly monitored and are fairly routine releases, but Methodology Rank 4 for flares may have to be used to estimate emissions for unusual events. The remainder of this section provides additional detail and guidance regarding the implementation of these methods.

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CLIMATE

'It Will Never Be The Same': North Dakota's 840,000-Gallon Oil Spill One Year Later

BY **EMILY ATKIN** OCT 21, 2014 3:02 PM

CREDIT: AP PHOTO/KEVIN CEDERSTROM

In this Oct. 11, 2013 file photo, cleanup continues at the site of an oil pipeline leak and spill north of Tioga, N.D.

One year ago, when more than 20,000 barrels (840,000 gallons) of crude oil spilled from a pipeline and soaked a wheat field in Tioga, North Dakota, the public almost never knew about it. After the spill was discovered by a lone farmer, it was not reported for nearly two weeks, and only after reporters from the The Associated Press asked about it specifically.

Now, a year later, environmentalists say North Dakota's oil spill reporting process has improved, but that more needs to be done to prevent those types of spills from happening in the first place. In North Dakota's Bakken shale, more than 1.2 million barrels of oil are produced every day, and spills from wells and pipelines happen frequently.

"The real lesson from this spill is that haste makes waste," Wayde Schaffer, a conservation organizer for the Sierra Club's North Dakota chapter, told ThinkProgress on Tuesday. "With the Bakken oil boom the development is outpacing the safeguards for the environment

and people's health that need to be in place. I don't see that lesson being taken to heart."

The real lesson from this spill is that haste makes waste. ... I don't see that lesson being taken to heart.

By all accounts, the year-old 20,000-barrel spill — one of the largest onshore spills in U.S. history — happened by chance. Tesoro Corp., the company who owns the pipeline, told the AP that the spill was caused by a lightning strike.

The freak nature of the accident is apparently why no one knew about it until wheat farmer Steve Jensen discovered it during a harvest. To this day, the farmland is still sopped with oil, and Tesoro is still working to clean it up. "It's a big cleanup and it's become part of our life," Jensen told the AP on Monday. "The ground is still saturated with oil. And they're out there seven days a week, 24 hours a day."

Tesoro has said it is committed to cleaning up the spill and "making things right." But the fact that the company didn't know what had happened, and that such a large release of oil into the environment took so long to be discovered and reported, sparked outrage at the time of the incident. The AP conducted an investigation after the spill, and found that nearly 300 oil spills and 750 "oil field incidents" had occurred in North Dakota since January 2012 — none of which were reported to the public.

Since then, Schaffer says things have improved. Before the spill, he said, state agencies would routinely be alerted when a spill occurred, but they didn't always let the public know. Now, the Health Department puts out press releases about significant oil spills — an improvement, Schaffer said, but not the greatest achievement.

"It's sort of a passive way of getting it out there," he said. "I mean, you still have to look for it. It'd be better if they would alert the public right away, but at least the information is available now."

Oil is messy. It does contaminate the soil, and it takes a long time to clean up. And it will never be the same.

North Carolina Oil and Gas Division spokesperson Ashley Ritter confirmed to ThinkProgress that the Health Department had started putting out press releases about significant oil spills since the Tesoro incident, and that her agency had begun putting out press releases about spills that happen on oil and gas well sites. The state Oil and Gas Division does not have jurisdiction over large pipelines like Tesoro's, but does regulate smaller diameter gathering pipelines and well sites. The agency also only has jurisdiction over spills that happen on well sites themselves — if any oil reaches outside that site, the spill falls into the jurisdiction of the Health Department.

Tesoro's pipeline is regulated by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA). But even the director of

that agency has admitted that it faces extreme difficulty in enforcing their regulations. PHMSA head Jeffrey Wiese said last year that the agency has "very few tools to work with" in enforcing safety rules, and that the regulatory process surrounding pipelines is "kind of dying."

Companies in North Dakota are required to report all their spills to whatever agency has jurisdiction over them. Those state agencies are required to put those reports into public record, but they are not required to put out press releases on their websites about every incident. "We use our best judgment," Ritter said. "If there is a situation where we think the public needs to know about it, we let the first responders know, and the first responders will get the information out to the immediate public. But if it's a 5-barrel spill on-site, then we're not going to put out a press release."

The public notification process is only one part of the story brought to light by the Tesoro spill. Since the spill, there have still been a number of contamination incidents in the state, and Schaffer says more needs to be done to stop them. Just this month, a North Dakota pipeline owned by Oasis Petroleum spilled 42,000 gallons of salty wastewater into a creek, and 300 barrels of oil and water were spilled at a well site owned by XTO Energy.

> *Oil companies are making a lot of money in North Dakota, and they should be spending money to put these safeguards in place so we don't have people's health and safety at risk.*

"It's one thing to report these spills but it's another thing to prevent them, and there hasn't been much movement in that direction," Schaffer said. "Oil is messy. It does contaminate the soil, and it takes a long time to clean up. And it will never be the same."

Schaffer said there has been somewhere in the neighborhood to 1,500 to 1,600 incidents of contamination by oil, gas, and wastewater from pipelines and well sites in 2013 — most of which were small, and none of which were as big as the Tesoro incident. But what that proves to him is that pipeline infrastructure needs to be updated, more pipeline inspectors need to be on the ground, and new technologies need to be implemented to monitor both the condition of the pipelines and whether an accident has occurred.

"We don't have those things in place, and we should," he said. "Oil companies are making a lot of money in North Dakota, and they should be spending money to put these safeguards in place so we don't have people's health and safety at risk."

For its part, Tesoro has said it could be $20 million and another year before the farm in Tioga is fully cleaned up and ready to be planted on again. But Jensen told the AP that the company is cooperating — excavating the contaminated soil, heating it until the oil is gone, and then replacing it. He told the AP he is optimistic that one day he'll be able to farm the land again.

That's at least some progress, but it's not the most important thing to take from the spill, Schaffer said.

"The one year anniversary is certainly nothing to celebrate," he said. "It's really only a good opportunity to remind people that these spills are taking place every day, and we need to take care of this problem."

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Two years after North Dakota oil spill, dirty pile still dwarfs clean pile

http://www.inforum.com/news/3848193-two-years-after-north-dakota-oil-spill-dirty-pile-still-dwarfs-clean-pile

By Amy Dalrymple / Forum News Service on Sep 26, 2015 at 7:46 p.m.

An aerial photo taken June 18, 2015, shows the site of the cleanup and remediation of the September 2013 Tesoro Logistics oil pipeline leak that released 20,600 barrels of oil into a wheat field near Tioga, N.D. Vern Whitten Photography

TIOGA, N.D. – Two years after North Dakota's largest oil pipeline spill, landowner Patty Jensen measures progress by how large the dirty pile of soil is compared to the clean pile.

Cleanup operations continue around the clock at the site of the Tesoro Logistics pipeline leak that saturated Patty and Steve Jensen's wheat field with 20,600 barrels of oil.

The company, which has spent $42 million on cleanup as of June 30, is about one-third to half done with the process to treat the contaminated soil, said Bill Suess, spill investigations program manager with the North Dakota Department of Health.

While the pile of contaminated soil dwarfs the piles that have been cleaned, Patty Jensen saw progress Friday during one of her frequent visits to the site.

"It's kind of starting to come together," she said.

Jensen keeps close tabs on the cleanup site, where the motto is "As long as Miss Patty's happy, everyone's happy." She brings the workers homemade pie and they keep the office Keurig coffee maker stocked for her.

"The relationship between Tesoro and their consultants and subcontractors and the landowners is one of the best I've ever dealt with," Suess said. "That goes a long way to make this a smooth-running project."

The company declined to comment on a potential end date for the cleanup, which has become part of the Jensens' lives since Steve discovered the spill while harvesting on Sept. 29, 2013. Both the Jensens and health officials say Tesoro Logistics has been dedicated to restoring the land.

"Up to this point, they have made an effort to get it fixed," Patty Jensen said. "But it's a pretty big mistake."

Cleanup site grows

The oil spill contaminated about 15 acres of cropland, but the cleanup site has grown to about 35 acres to accommodate areas where excavated soil is being stockpiled, Suess estimates.

"It's so huge," Jensen said.

Crews excavate soil nearly 50 feet deep and use technology called a Thermal Desorption Unit to "bake" the hydrocarbons out of the soil.

The Jensens say they have a lot of confidence in the contractor, Nelson Environmental Remediation of Alberta, Canada, which operates the TDU system and carefully separates topsoil from other layers.

"They've done this all over the world," Jensen said. "They know what they're doing."

Co-owner Warren Nelson said the process will restore the land so it's productive for farming.

"It'll go back to as good if not better condition," Nelson said.

The TDU operates 24/7 can clean up to 1,000 tons of contaminated soil per day. Soil samples are then tested by a third party, and so far all samples have come back clean, Nelson said.

The company has two more TDUs on location, but the natural gas supply to the site is only adequate to run one unit, Suess said.

The region has plenty of natural gas - the state flared 20 percent of natural gas produced in July - but the challenge is getting enough gas to the site by pipeline.

"That would drastically cut back the amount of time needed," Suess said.

Tesoro Logistics is routinely evaluating the operation, including the use of additional natural gas, spokeswoman Tina Barbee said.

In addition to the environmental contractors, Tesoro Logistics is paying North Dakota State University soil scientists $300,000 to help restore the land. They'll begin working with test plots during the next growing season.

"There's a fair bit of work to put it back to productivity," said associate professor Tom DeSutter. "One of the things that we always stress is making sure that when the soil is replaced that the compaction is monitored very closely. The actual soil compaction where the roots will reside can have a lot to do with how productive those soils will be."

Lessons the NDSU scientists learn can be applied to restore land contaminated by oil in other areas of the state, DeSutter said.

Fine still pending

The North Dakota Department of Health will fine Tesoro Logistics because of the spill, but the amount has not yet been determined, said Dave Glatt, chief of the Environmental Health Section.

The penalty will take into consideration how quickly the company responded and how thorough the response is, Glatt said.

"Tesoro has been very responsive in getting to the cleanup, even though it's costing them a lot of money," Glatt said. "They've been committed to getting it cleaned up and bringing in more help as needed."

Jensen said she thinks Tesoro Logistics should be required to reimburse the health department for its costs to investigate and oversee the cleanup.

"It's huge when you think of the time they've had to dedicate to that," Jensen said. "Is that the taxpayers' responsibility? The people shouldn't have to pay for that."

The Pipeline and Hazardous Materials Safety Administration regulates the pipeline, but it's unclear if the federal agency plans to seek civil penalties. The agency did not respond to Forum News Service inquiries last week.

The North Dakota Public Service Commission meets with PHMSA representatives Tuesday, the anniversary of the spill, and commissioner Brian Kalk said the Tesoro Logistics spill is one topic he plans to bring up.

Tesoro Logistics said it works closely with PHMSA in regard to the cleanup, as well as strengthening the controls on its pipeline system.

"We have put systems and controls in place to identify and prevent this type of spill in the future," Barbee said.

An independent, third-party report confirmed that the likely cause of the hole in the pipeline was from electrical discharge, consistent with a lightning strike.

The size of the spill - 865,200 gallons - put a spotlight on the need for stronger controls on pipelines to prevent spills and detect leaks sooner.

Since the spill, the Jensens have approved one natural gas pipeline for their land - already criss-crossed with pipelines - but they've said no to other proposed pipelines.

"We have to let the natural gas lines go in, but I have not let a saltwater go in because I don't trust that the regulation is there," Jensen said.

Jensen said she tries to focus on the positives that can come from the spill, even using some excavated boulders and petrified wood in their landscaping. More important to Jensen are the lessons that can be learned to prevent spills.

A representative of another pipeline company once told her: "Every time I see this in the paper, it makes me work harder that it's not us."

Tesoro Logistics pipeline spill near Tioga

Discovered Sept. 29, 2013
Estimated spill: 20,600 barrels of oil
Estimate of recovered oil: 6,000 barrels of oil, or 30 percent
Area contaminated: 15 acres
Overall site of cleanup: 35 acres of farmland
Amount of soil excavated as of mid-September: 449,543 tons
Average amount of soil cleaned each day: Up to 1,000 tons
Cleanup costs as of June 30: $42 million
Sources: Tesoro Logistics, North Dakota Department of Health and Nelson Environmental

(701) 235-7311

NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 6, 2009

Mr. Michael McCann
Vice President of Pipeline and Terminals
Tesoro Refining and Marketing Company
300 Concord Plaza Drive
San Antonio, TX 78216-6999

CPF 5-2009-0002

Dear Mr. McCann:

On September 9-11, 2008, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected Tesoro Refining and Marketing Company's (TRMC) procedures for Operations and Maintenance Procedural Manuals in Wilmington, California.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. §192.225 Welding procedures.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code "Welding and Brazing Qualifications" (incorporated by reference, see §192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s).

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

Tesoro Refining and Marketing Company has no welding procedures. If TRMC has a separate welding manual, and if that manual addresses the welding procedures, then it should be included or referenced in its O&M manuals. The welding procedures need to specify the section and the edition of API 1104 under which it is qualified.

2. §192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

Tesoro Refining and Marketing Company's welding procedures do not specify how it will protect welding operations from weather conditions that could negatively impact the weld quality. If TRMC has a separate welding manual, and if that manual addresses weld protection from weather, then it should be included in its O&M manuals.

3. §192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.
(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent of SMYS may not deflect the pipe more than 12 1/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

Tesoro Refining and Marketing Company does not preclude the use of miter joints, yet has no procedures for constructing miter joints. If TRMC has a separate welding manual, and if that manual allows miter joints, then the miter joints should be included or referenced in its O&M manuals.

4. §192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

Tesoro Refining and Marketing Company has no procedures for surface preparation prior to welding. If TRMC has a separate welding manual, and if that manual addresses preparation for welding, then it should be included or referenced in its O&M manuals.

5. §192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Secs. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

Tesoro Refining and Marketing Company has no procedures to examine a buried pipeline when exposed for external corrosion and coating deteriation.

6. §192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must-
(1) Be applied on a properly prepared surface;
(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
(3) Be sufficiently ductile to resist cracking;
(4) Have sufficient strength to resist damage due to handling and soil stress; and,
(5) Have properties compatible with any supplemental cathodic protection.
(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

Tesoro Refining and Marketing Company has no procedures for ensuring adequate protective coating for buried pipe. TRMC, in its O&M manuals, only states the pipeline should be coated. TRMC should specify procedures for coating specifications, type, installation, and protection.

7. §192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
(c) Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

Tesoro Refining and Marketing Company has no procedures for electrical isolation. TRMC should have procedures isolating its buried pipeline from other underground structures unless they are all interconnected and cathodically protected as a single unit.

8. §192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

Tesoro Refining and Marketing Company has no procedures for installing test leads. The procedures should make sure the test wire is mechanically secured, electrically conductive, has no stress concentration, and the point of connection to bare metal is coated.

9. §192.479 Atmospheric corrosion control; General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
(b) Coating material must be suitable for the prevention of atmospheric corrosion.
(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will-
(1) Only be a light surface oxide; or
(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

Tesoro Refining and Marketing Company has no procedures to ensure proper coating materials are used to protect their pipelines against atmospheric corrosion.

10. §192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located	Then the frequency of inspection is
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months**

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec. 192.479.

Tesoro Refining and Marketing Company has no procedures for monitoring atmospheric corrosion. TRMC, in its O&M manuals, requires the exposed pipes to be coated. TRMC need to inspect portion of the pipeline that is exposed at least once every 3 years not exceeding 39 months to ensure the applied coating is effective at protecting their pipeline against atmospheric corrosion.

11. §192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until-
(1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure; and
(2) Each potentially hazardous leak has been located and eliminated.
(b) The test medium must be liquid, air, natural gas, or inert gas that is-
(1) Compatible with the material of which the pipeline is constructed;
(2) Relatively free of sedimentary materials; and,
(3) Except for natural gas, nonflammable.

(c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

	Maximum hoop stress allowed as percentage of SMYS	
Class location	**Natural Gas**	**Air or inert gas**
1	**80**	**80**
2	**30**	**75**
3	**30**	**50**
4	**30**	**40**

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

Tesoro Refining and Marketing Company has no procedures for pressure testing its pipeline. TRMC has detailed hydrotest procedures in its O&M manuals (appendix B), however, these procedures are for hazardous liquid pipeline and not natural gas pipelines.

12. §192.605 Procedural manual for operations, maintenance, and emergencies.

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.
(3) Making construction records, maps, and operating history available to appropriate operating personnel.

Tesoro Refining and Marketing Company has no procedure requiring that all construction records, maps, and operating history are available to its operating personnel.

13. §192.614 Damage prevention program.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
(ii) In the case of blasting, any inspection must include leakage surveys.

Tesoro Refining and Marketing Company has no procedures in its damage prevention program for conducting leakage surveys when there may be blasting close to its pipeline.

14. §192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
(3) Prompt and effective response to a notice of each type of emergency, including the following:
(i) Gas detected inside or near a building.
(ii) Fire located near or directly involving a pipeline facility.
(iii) Explosion occurring near or directly involving a pipeline facility.
(iv) Natural disaster.

Tesoro Refining and Marketing Company has no procedures for responding to fire, explosion, and natural disasters that may affect the pipeline integrity or safe operation.

15. §192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

Tesoro Refining and Marketing Company has no procedures for investigating failures. TRMC needs to make certain that all contributing causes of a failure is investigated and the possibility of a recurrence minimized.

16. §192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

Tesoro Refining and Marketing Company has no procedures for tapping pipelines under pressure.

17. §192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is–
(1) In good mechanical condition;
(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a);; and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Tesoro Refining and Marketing Company did not have procedures for inspecting and testing its pressure limiting devices as required in §192.739(a).

Proposed Compliance Order

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Tesoro Refining and Marketing Company. Please refer to the *Proposed Compliance Order* that is enclosed and made a part of this Notice.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 5-2009-0002** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 H. Monfared (#120751)

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Compliance Proceedings

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Tesoro Refining and Marketing Company a Compliance Order incorporating the following remedial requirements to ensure the compliance of Tesoro Refining and Marketing Company with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to welding procedures. TRMC must prepare welding procedures and ensure these procedures are qualified (by explicit reference) to the appropriate industry standard.

2. In regard to Item Number 2 of the Notice pertaining to protection from weather. TRMC must prepare procedures to protect welding operation from weather conditions that would impair the quality of the completed weld.

3. In regard to Item Number 3 of the Notice pertaining to miter joints. TRMC must prepare procedures to ensure that a miter joint on steel pipe do not deflect more than 3°, 12½°, and 90° if the hoop stress is >30%, <30% but >10%, and <10% of SMYS respectively. Alternatively they may preclude the use of miter welds.

4. In regard to Item Number 4 of the Notice pertaining to preparation for welding. TRMC must prepare procedures to ensure the welding surfaces are clean and free of any material that may be detrimental to the weld and the pipe or component are aligned before beginning any welding.

5. In regard to Item Number 5 of the Notice pertaining to examination of buried pipeline when exposed. TRMC must prepare procedures to ensure whenever any portion of a buried pipeline is exposed, the exposed portion are examined for evidence of external corrosion.

6. In regard to Item Number 6 of the Notice pertaining to protective coating. TRMC must prepare procedures to ensure each external protective coating, weather conductive or insulating, applied for the purpose of external corrosion control for buried pipe meets the requirement of §192.461.

7. In regard to Item Number 7 of the Notice pertaining to electrical isolation. TRMC must prepare procedures to ensure each buried pipeline is electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

8. In regard to Item Number 8 of the Notice pertaining to test leads. TRMC must prepare procedures to ensure each test lead is connected, mechanically secured, electrically conductive, has minimal stress concentration on pipe, and coated at the point of connection to the pipeline.

9. In regard to Items Number 9 and 10 of the Notice pertaining to atmospheric corrosion. TRMC must prepare procedures to ensure a portion of pipeline that is exposed to

atmospheric corrosion is properly coated, and subsequently monitored, at least once every 3 calendar years not exceeding 39 months for evidence of atmospheric corrosion. Any atmospheric corrosion shall be evaluated and remediated, as necessary.

10. In regard to Item Number 11 of the Notice pertaining to test requirements. TRMC must prepare procedures to ensure a new segment of pipeline, or returns to service a segment that has been relocated or replaced, is tested in accordance with subpart J.

11. In regard to Item Number 12 of the Notice pertaining to procedural manual for operations, maintenance and emergencies. TRMC must prepare procedures to ensure construction records, maps, and operating history are readily available to appropriate operating personnel.

12. In regard to Item Number 13 of the Notice pertaining to damage prevention program. TRMC must prepare procedures to inspect pipelines that could be damaged by excavation activities such as blasting, and if blasting is used, the inspection must include a followed leakage survey.

13. In regard to Item Number 14 of the Notice pertaining to emergency plans. TRMC must prepare procedures to minimize the hazard resulting from gas pipeline emergencies such as fire near or directly involving a pipeline facility, explosions near or directly involving a pipeline facility, and natural disasters.

14. In regard to Item Number 15 of the Notice pertaining to investigation of failures. TRMC must prepare procedures for analyzing accidents and failures for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

15. In regard to Item Number 16 of the Notice pertaining to tapping pipelines under pressure. TRMC must prepare procedures to ensure that if hot tapping is allowed on a pipeline under pressure, it is performed by a crew qualified to make hot taps.

16. In regard to Item Number 17 of the Notice pertaining to inspection and testing pressure limiting devices. TRMC must prepare procedures to ensure its pressure limiting stations, relief devices, and pressure regulating stations are inspected and tested once per calendar year, but not exceeding 15 months, to ensure they are in good mechanical condition, have adequate capacity, set to control or relive at the correct pressure, and properly installed.

18. **Within 60 days of issuance of the Final Order, TRMC must complete the above items, and submit the required documentation and procedures to the Director, Western Region, Pipeline and Hazardous Material Safety Administration, 12300 West Dakota Avenue, Suite 110, Lakewood, Colorado 80228.**

19. Tesoro Refining and Marketing Company shall maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

Crack in idle Phillips 66 pipeline spews crude oil onto Wilmington streets

Posted: 03/18/14, 6:43 AM PDT | Updated: on 03/18/2014

HAZMAT investigates an oil leak in Wilmington

A crack in an idle Phillips 66 oil pipeline, possibly caused by this week's 4.4-magnitude earthquake, spewed thousands of gallons of crude oil onto a residential street in Wilmington, officials said Tuesday.

Residents in the 1200 block of North Neptune Avenue reported the foul-smelling, dark liquid oozing out of fissures in the street late Monday afternoon, prompting a response from the Los Angeles City Fire Department and county Fire Department hazardous materials units. Phillips 66 officials suspected the pipeline may have been one of theirs, and took over the cleanup Tuesday.

They didn't find the cause of the leak until late Tuesday afternoon, after vacuuming out 70 barrels of oil from the area, fire officials said.

"After a thorough investigation of the source, we can confirm the leak is coming from an idle pipeline owned by Phillips 66," said Monica Silva, a spokeswoman for the oil company. "We are working to stop the leak and have recovered approximately 30 barrels of oil. Clean-up efforts continue."

Silva declined to elaborate on why the unused 10-inch pipeline was filled with crude oil.

County Hazardous Materials Specialist Don Miguel Ellis said that, though the oil seeped into nearby soil, it isn't expected to affect groundwater reserves or create any other major environmental concerns. The only human health impacts were some nearby residents complaining of headaches from the foul-smelling raw crude, and the inconvenience created by street closures, Ellis said.

Normally, when a pipeline is not being used, oil companies will fill it with concrete slurry. However, if they think they may want to use the line again, they try to keep it viable. In this case, the oil may have been stored in the line to keep it from corroding or collapsing, fire officials said. Silva said oil company officials will not say more about the issue until Wednesday.

"A unified command with local authorities has been established and Phillips 66 crews are on site and working to minimize impact to the community," Silva said in a written statement. "As a precaution, we also are monitoring the air quality. The health and safety of our communities is important to us."

Rep. Janice Hahn, D-San Pedro, visited the site on Tuesday out of "concern for the safety and well-being of the residents of Wilmington," she said in a statement. "The harsh, crude oil smell is not only horrible, but can also be potentially harmful to the neighborhood residents and environment."

"As a member of the House Transportation and Infrastructure Subcommittee on Railroads, Pipelines and Hazardous Materials, I plan to make this oil spill incident a priority," Hahn said. "I have already reached out to the subcommittee to find out what federal actions we can take to ensure that an incident like this will not happen again, and that there is proper oversight with our nation's pipelines.

"We have to protect the residents of Wilmington and the environment from the risks of hazardous materials transportation."

The pipeline, which is not a main line, stretches along Neptune Avenue from the border of Carson, at Lomita Boulevard, to the southern end

of Wilmington at G Street, according to Ellis.

“It was quasi-abandoned, so they don’t use it but they don’t close it out completely because they may use it again,” Ellis said. “It probably would have been the right thing to do to evacuate the line from product. (They may have left oil in it) to keep it from corroding because a lot of these lines are old already and, if they abandon it, it corrodes. It’s not proven, but (the leak) could have had something to do with the earthquake because it was discovered at 4:30 p.m. Monday.”

Ellis said that Phillips 66 officials were developing a plan Tuesday afternoon to remove the rest of the oil and clean and repair the area.

“It’s a significant spill in a public area,” Ellis said. “But health risks are minimal.”

More

KAMALA D. HARRIS
Attorney General

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DEPARTMENT OF JUSTICE

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May 17, 2013

Robert B. Weisenmiller, Ph.D.
Chair, California Energy Commission
1516 Ninth Street, MS-33
Sacramento, CA 95814

Dear Chair Weisenmiller:

After a nine month investigation that involved close cooperation between our agencies, we have reached an agreement with Tesoro that resolves our concerns arising from Tesoro's proposed acquisition of BP's Southern California refining and marketing assets. The concessions we received from Tesoro will advance our effort to protect competition, the environment, and jobs in the state of California. We could not have achieved such a resolution to the investigation without the generous assistance of the CEC and its staff, and for that we are grateful.
At the outset of the investigation, we had significant concerns about the potential effect of the acquisition on competition. Over the course of the investigation the parties and various third parties combined to produce millions of pages of documents and voluminous amounts of data. We reviewed these documents and data, subpoenaed the parties and numerous third parties for testimony, and secured a leading economist in the field of oil and gas to conduct various analyses of the markets at issue. After a thorough investigation and review of the evidence, many of our initial market competition concerns were addressed, and our office decided that our remaining consumer, environmental and job security issues were appropriately addressed through a letter-agreement. Some of the facts that lead us to this conclusion include:

- Demand for CARB gasoline has declined over the past several years resulting in excess capacity;
- A significant amount of excess capacity will be controlled by refiners other than Tesoro;
- The acquisition leaves intact seven refiners on the West Coast; and
- The structure of the retail market has become less vertically integrated and Tesoro, along with many other refiners, no longer sets street prices for gasoline.

Below is a summary of the agreement we have reached with Tesoro, including a description of our remaining issues and the binding commitments Tesoro has made to address them.

Competition Issues

Capacity Concerns -- Reductions in CARBOB capacity have led to increases in the prices California consumers pay for gasoline. One of our primary concerns here was that the acquisition would enable Tesoro, as the largest refiner in Southern California, to reduce capacity and increase prices. In response to these concerns, however, Tesoro has agreed not to reduce capacity of CARBOB for a period of three years. Over the next three years, Tesoro will maintain the historical average daily production for both the Carson and Wilmington refineries. Tesoro has also agreed to increase CARBOB capacity in the amount of 400 barrels per day to ensure that California continues to have excess CARBOB capacity on hand in the event of an unplanned refinery outage. Tesoro will also provide our office with monthly production volume data for all of its West Coast refineries, so that we can monitor Tesoro's compliance with these commitments.

Maintenance of the ARCO Brand -- As part of the acquisition Tesoro will take ownership of the ARCO brand in Southern California. The ARCO brand plays an important role as the value leader in the market for branded retail gasoline in Southern California. It is important to our office that consumers continue to reap the benefits of ARCO's lower prices for years to come. Accordingly, Tesoro has agreed to maintain ARCO's status as a low cost fuel provider. Tesoro has agreed to provide our office with data for average monthly dealer tankwagon prices for all of its retail brands in Southern California so that we can monitor its compliance with this commitment.

Environmental Issues

Tesoro has stated that the acquisition will enable it to achieve significant synergies, some of which will benefit the environment by lowering greenhouse gases and emissions. Specifically, Tesoro has stated that the acquisition will enable it to install a single distillate desulfurization unit ("DDU") for both the Carson and Wilmington refineries.[1] The California Air Resources Board has studied this issue and has concluded that the installation of a DDU for the combined facility would result in a reduction of emissions and greenhouse gases. Additionally, Governor Brown sent a letter to Tesoro on April 8, 2013, stressing the importance of installing a DDU should the acquisition proceed. Tesoro has committed to provide our office with an annual progress report detailing the steps it has taken to realize the synergies resulting from the acquisition, including the installation of a DDU, so that we can monitor its commitments to lower greenhouse gasses and emissions.

[1] Currently, both Carson and Wilmington utilize fluid catalytic cracking ("FCC") units to convert feedstock (gasoil) into intermediate products that the refineries further process. The FCC units produce much lower cracking yields (and result in higher emissions and greenhouse gases) than a DDU.

Job Security

Acquisitions such as this one often lead to significant layoffs, which are then touted as "synergies" by the companies. Our office was concerned that this acquisition might lead to similar reductions in jobs. As a result, Tesoro has agreed not to eliminate any jobs at either the Carson or Wilmington refineries for a period of two years. Tesoro will provide our office with an annual report detailing employment data at the refineries so that we can monitor its compliance with this commitment.

In conclusion, we believe that these commitments will help ensure that California's oil and gas markets remain competitive for years to come, help to reduce greenhouse gases and emissions, and protect jobs for potentially thousands of Californians. Over the next several years we will be vigilant in monitoring Tesoro's compliance with its commitments, and we hope to continue working closely with the CEC in this respect. Through our combined expertise and enforcement authority we can ensure that Tesoro follows through with its commitments and the synergies resulting from this acquisition will benefit all Californians.

Sincerely,

KATHLEEN E. FOOTE
Senior Assistant Attorney General

For KAMALA D. HARRIS
Attorney General

KEF:dbc

Consumer Watchdog
EXPOSE. CONFRONT. CHANGE.

NEWS RELEASE

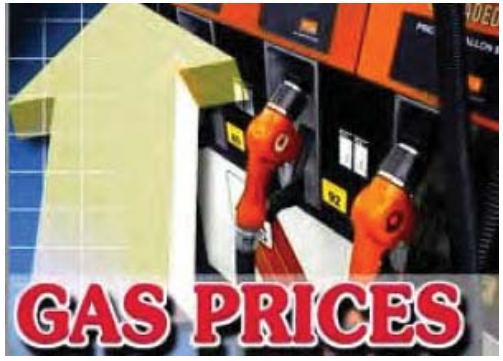
Consumer Watchdog Calls For Sunlight On Big Oil Refiners To Avert CA Gasoline Price Spikes; State Energy Commission Panel To Make Recommendations On Transparency For Refiners

4/22/2016

Contact Info
Name:
Jamie Court & Cody Rosenfield

Email:
jamie@consumerwatchdog.org (mailto:jamie@consumerwatchdog.org)

Sacramento, CA – Consumer Watchdog told a state panel looking into gasoline price manipulation today that a handful of big oil refiners have been able to charge California drivers 70 cents to $1 more per gallon than the rest of America because they have an information advantage over the rest of the market, the public and regulators.



Consumer Watchdog asked the California Energy Commission's Petroleum Market Advisory Committee to recommend public disclosure by the state's oil refiners of:

- Refinery Maintenance Schedules & Updates
- All Trades, Including Exchanges & Production Agreements
- Prices Refiners Charge Their Branded Stations, Known As Dealer Tank Wagon Prices
- Real Time Imports and Exports

Read Consumer Watchdog's presentation here: http://www.energy.ca.gov/assessments/petroleum_market/2016-04-22/presentations/Consumer_Watchdog_April_PMAC_Presentation.pdf (http://www.energy.ca.gov/assessments/petroleum_market/2016-04-22/presentations/Consumer_Watchdog_April_PMAC_Presentation.pdf)

"Four oil refiners control 80% of the state's gasoline production and the inside information they know about each others' supplies and prices allow them to rig the

market to keep gas supplies low, prices high, and drive out competition," said Jamie Court, president of Consumer Watchdog. "California oil refiners had their most profitable year from refining ever last year because they kept California running on empty and Californians in the dark."

He testified the transparency measures would ease volatile California gas prices disconnected from crude oil and production costs; stop 'what the market will bear' pricing, and stir competition.

Consumer Watchdog said that oil refiners already have insider information that is denied smaller traders, the public, anti-trust regulators and station owners, who have the potential to take steps to drive down prices in times of tight supply or when refiners make anti-competitive moves.

Court noted that California's extraordinary gap with US gas prices in 2015 and record oil refining profits in the state last year were driven by the fact that Exxon's Torrance refinery, which supplies 20% of Southern California's gasoline, was offline almost the year. Its competitors knew this fact and were able to take advantage of it because of production agreements they had with Exxon to make up for lost supplies, but the rest of the market was in the dark. As a result, imports of gasoline were tiny and refiners kept the state running on empty, commanding outrageously high pump prices given low production costs.

"If the true state of Exxon Torrance was publicly known, oil refiners could not have shorted California's gasoline market all year long," said Court.

Court pointed out refiners know who conduct trades through their relationships and shared consultants, refinery maintenance schedules through shared maintenance teams, the duration of outages and production delays through secret production and exchange agreements with each other to compensate for lost supply. They also know the wholesale prices their competitors charge their branded stations corner by corner through the Lundberg Survey, which only refiners appear to be able to have access to.

Consumer Watchdog showed how even in times of ample supply oil refiners in Southern California, where 80% of the stations are branded and refiners determine the prices, set artificially high prices at their branded stations to keep street prices higher than they should have been.

In addition, Court pointed out that the Exxon increased its gasoline sales by 4% in 2015 despite the fact that its only refinery in Torrance was out for 11 months of the year. Exxon did this through production agreements with its competitors to use their refineries, including Tesoro, that signaled to the other refiners that Torrance would not be online for a long period of time. Meanwhile misinformation about Torrance led the market to believe that the refinery would be back online throughout the year, because Exxon had no duty to report its actual condition or true estimated uptime, sparking shortages and price spikes.

"Misinformation about Exxon Torrance led the market to stop imports in the summer of 2015 and cost consumers billions of dollars extra at the pump in 2015," said Court. "A simple filing with the state about the true condition of the refinery would have opened this market to exports and saved consumers as much as $10 billion at the pump, which is how much more Californians paid in 2015 than US drivers for gasoline."

"All imports of gasoline stopped in July of 2015 because of misinformation about Exxon's Torrance refinery coming online and that drove gas prices in LA over $4 per gallon when the rest of America was hovering in the $2 range," said Court. "Chevron and Tesoro knew the state of the refinery and bought up all available supplies on the spot market, sending prices up like a rocket over night. In real time, however, there was no record of these actions. A little sunlight would have deterred these refiners from cornering the market."

Court also called into question the independence of the only source of market information, the Oil Price Information Service or OPIS, a private subscription service that was purchased this year by I H S, a company among whose owners also are the largest investors in the state's big oil refiners. Vanguard Group owns 6% of OPIS (IHS) and is the largest shareholder in Exxon, Chevron, Tesoro, and second largest shareholder in Valero. Blackrock owns 4% of OPIS and is the second largest shareholder in Exxon, Chevron, Tesoro and the first largest in Valero.

"When the oligopoly of oil refiners in California also own the principal information service that sets the price of trades there's an even greater need for mandated

When the oligopoly of oil refiners in California also own the principal information service that sets the price of trades there's an even greater need for mandated disclosure of information so that oil refiners are honest with the market," said Court.

Consumer Watchdog said among the benefits of transparency are that it will:

- Create more opportunities for additional traders and importers to participate in the market;
- Empower branded retailers to demand competitive pricing from refiners;
- Guard against predatory exports that short a short supplied gasoline market
- Give regulators and anti-trust enforcement officials tools to understand anti-competitive pricing in real time.

-30-

Related Focus Areas:

Dirty Money Watch (/focusarea/dirty-money-watch)

Holding Big Oil Accountable (/focusarea/holding-big-oil-accountable)

Reforming Politics (/focusarea/reforming-politics)

Tags:

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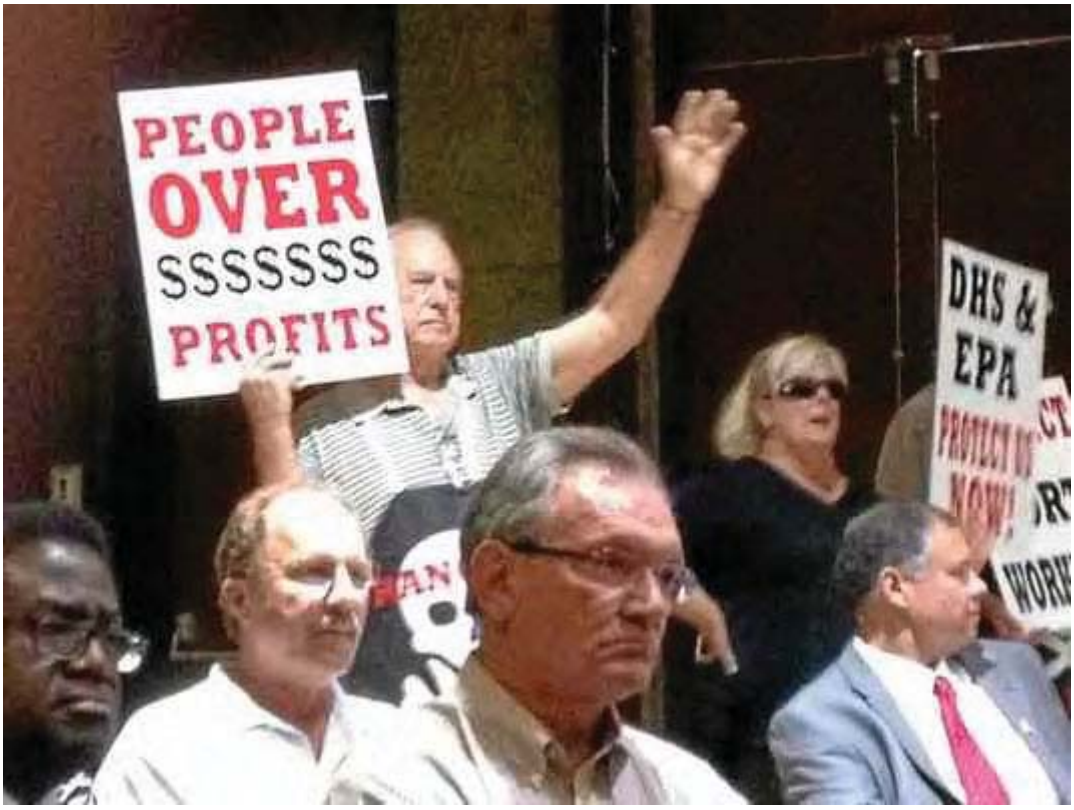
http://www.dailybreeze.com/business/20140911/critics-not-satisfied-by-assurances-that-rancho-lpg-storage-tanks-in-san-pedro-meets-all-federal-standards

Critics not satisfied by assurances that Rancho LPG storage tanks in San Pedro meets all federal standards



Chuck Hart of San Pedro was among residents objecting to the Rancho LPG chemical tanks at this week's community meeting with federal officials. (Photo by Donna Littlejohn / Daily Breeze)

By **Donna Littlejohn**, *Daily Breeze*

POSTED: 09/11/14, 6:15 PM PDT | UPDATED: ON 09/11/2014
5 COMMENTS

Tanks at the Plains LPG (formerly Amerigas) site loom in the background of the North San Pedro neighborhood near Mary Star High School. October 2010 file photo. (Scott Varley / Staff Photographer)

Federal officials from anti-terrorism and environmental protection departments assured about 200 San Pedro residents this week that Rancho LPG, a chemical storage tank facility on North Gaffey Street, was in full compliance with U.S. regulations.

But it's not what most in the crowd wanted to hear.

The two-hour meeting Wednesday, on the eve of the 13th anniversary of 9/11, was punctuated by outbursts as several impassioned, sign-toting attendees objected to speakers who said that thorough inspections — followed by more than $7 million in upgrades made by the facility — have determined that Rancho meets government safety standards.

When the meeting was over, Janet Gunter, the San Pedro resident who has been at the forefront of the battle to force the tanks to move, said the fight would go on.

"This is not over," she said. "This is wrong. It's nine kinds of wrong."

The forum was organized by U.S. Rep. Henry Waxman, D-Manhattan Beach.

Rancho, long a target of residents who believe it poses a grave danger to the surrounding community, has been included among the nation's high-risk facilities being monitored by the U.S. Department of Homeland Security, subjecting it to more stringent regulations and oversight, according to David Wulf, compliance division

director for the department established after the 9/11 terrorist attacks on the World Trade Center in New York.

As part that program, Rancho is required to develop and implement a site security plan, which it has done, Wulf said.

“It’s not a program that can eliminate all risks, but it can reduce risks,” Wulf told the audience of the federal anti-terrorism oversight.

Meanwhile, Kay Lawrence of the Environmental Protection Agency said that agency had spent three years investigating the facility, beginning in April 2010, and settled a claim for risk management violations with the company this summer. She said the company spent $7.2 million in upgrades and improvements to satisfy the agency’s concerns, in addition to paying $260,000 in civil penalties.

“I can’t overemphasize to you enough that we have taken this very seriously and we’ve invested a lot of time and resources into it,” she said of the lengthy investigations that included participation of one of the agency’s top investigators.

But many who attended the meeting at Peck Park Recreation Center were in no mood for reassurances, shouting over the speakers several times.

“It’s practically a fuse waiting to be lit,” said one audience member. “It’s only safe if it’s in an isolated area.”

“Something’s going to happen, it’s just a matter of time,” another man called out from the back of the room. “This is just crazy. Do something!”

Standing in a line, several demonstrators either wore or waved signs that included slogans like “ISIS + RANCHO = DEATH,” “Protect Port Workers!” and “People over $$$$ Profits.”

Lawrence and other federal officials said they are bound by government standards and, in Rancho’s case, the facility meets those standards. But they encouraged audience members to submit concerns going beyond that to the federal government.

Some critics said the government could do more, adding that more specifics need to be required of the company including copies of its liability insurance documents and a specific seismic figure that the plant could survive.

“Between your two agencies you could make life miserable for Rancho,” said one man. “Make life miserable for Rancho.”

“Shut the damn thing down,” called out Chuck Hart of San Pedro.

Central to opponents’ concerns is that the facility, which was established at 2110 N. Gaffey St. under a different operator in the 1970s, is simply in the wrong place.

In case of an earthquake or terrorist attack, opponents argue, much of the area surrounding the volatile butane/propane storage tanks — for miles around — would be vaporized.

Surrounded by homes with several nearby schools, the site should be rezoned by the city of Los Angeles, critics said, which could finally force the business to move to a more remote area.

“Please, understand my limits as a federal regulator,” Lawrence told the crowd.

Wulf agreed that chemical plants such as Rancho are “attractive targets” for terrorists, but said the facility is in full compliance with what the government requires.

“We work within the parameters of the regulatory authority given by Congress and we do this to the best of our ability,” Wulf said.

Minding the Climate Gap

EXECUTIVE SUMMARY

What's at Stake if California's Climate Law isn't Done Right and Right Away

Manuel Pastor, Ph.D. | Rachel Morello-Frosch, Ph.D., MPH | James Sadd, Ph.D. | Justin Scoggins, M.S.

Acknowledgments

The research work for this project was supported by a grant from the William and Flora Hewlett Foundation. The conclusions and opinions in this document are those of the authors and do not necessarily reflect the views of the funder or our respective institutions.

Introduction

With the passage of the bipartisan Global Warming Solutions Act (AB 32) in 2006, California demonstrated its leadership on environmental issues by committing to the reduction of greenhouse gas (GHG) emissions. What is often overlooked when evaluating the impacts of climate change policy like AB 32 is that beyond large-scale impacts – like decreasing global carbon counts, tempering the rise in global temperature, and staving off countless natural disasters – GHG reductions can have related local impacts.

When regulations prompted by AB 32 take effect in early 2012, Californians will not only see a reduction in GHG emissions, they are also likely to see a reduction in harmful chemical compounds that are emitted alongside GHGs – pollutants such as particulate matter, sulfates, and volatile organic compounds.

That's good news for all Californians. Too few Californians are aware of this opportunity for potential health gains and the fact that many economists predict that AB 32 will also produce long-term net growth in jobs. California lawmakers and regulators should better broadcast these facts – and they could also build more public support for policies that will prevent climate change by ensuring that mitigation strategies also lead to cleaner air where it is needed most: in poor neighborhoods and communities of color.

Why are these neighborhoods and communities overburdened? In a recent report entitled *The Climate Gap* (Morello-Frosch, et al. 2009), we showed that climate change does not affect all Americans equally. Communities of color and low-income neighborhoods suffer the greatest health and economic consequences. Among the many disparate impacts, these Americans are more likely

Why The Other Pollutants Matter

Consider the La Paloma power plant and the Exxon Mobil refinery in Torrance. The La Paloma power plant sits about 35 miles west of Bakersfield in an abandoned oil field just outside of the small town of McKittrick (population 160) with fewer than 600 residents in the surrounding 6 miles, and no other facilities in the immediate vicinity. The Exxon Mobil refinery, on the other hand, has nearly 800,000 people in the encircling 6 miles and is one of many facilities in its surrounding area.

While these two facilities seem quite different, they share one similarity – according to recently released 2008 GHG emissions data from the California Air Resources Board, they both emit between 2.5 and 3 million tons of carbon dioxide each year. However, La Paloma releases 48.6 tons of particulate matter per year while Exxon Mobil emits 352.2 tons. This staggering emissions burden is important to people who live in Torrance's dense neighborhoods, yet this fact is often ignored in the debates about how we might best implement AB32.

Why is the difference between reducing emissions at La Paloma and in Torrance overlooked in the discussion about mitigating climate change? Part of the reason is that too much of the discussion stays at the macro-level: climate change is imagined as major weather events and sea level rise. While the catastrophic potential of climate change is well documented, the story of the climate gap – the often hidden and unequal impacts on people of color and the poor in the United States, ranging from increased air pollution and higher prices for basic necessities to job loss – unfolds at the neighborhood level and is just being understood.

Partly because of this, systemic efforts to combat climate change have focused primarily on reducing carbon with little, if any, regard for how these efforts might also worsen or ameliorate the climate gap. Shining a light on the gap is no excuse for forgetting the health concerns of the much smaller population near the La Paloma power plant – or for backing away from the shared global goals of legislation like AB 32 – but it does provide yet another prism for our work and another way to generate widespread support for tackling the challenge of climate change.

to be exposed to dirtier air, more vulnerable to extreme weather events, and suffer more than others by the rising costs of basic necessities and economic dislocations caused by climate change.

This report examines one aspect of this "climate gap" in the context of market-based strategies to limit greenhouse gas emissions. Such market strategies tend to come in two types: either charging a fee on carbon emitters to encourage reduction or placing emitters within a cap-and-trade system in which firms receive or purchase emissions allowances and are allowed to buy or sell allowances depending on their ability or desire to reduce their own pollution versus paying someone else to reduce theirs.

It is argued that such market-based strategies make little difference with regard to GHGs – reducing carbon emissions anywhere has the same global impact. But what are the potential benefits from targeting the reductions in greenhouse gases from sources that also emit high levels of other dangerous pollutants that have localized health impacts? This report looks at the consequences of a "blind" market strategy that ignores these toxic chemicals or co-pollutants – and the climate gap with regard to who they affect and where. We argue that such an approach could waste an opportunity to further enhance the positive health impact of AB 32 at the local level.

Think of it this way. Imagine a factory whose pollution caused drinking water in a city to become unsafe. Would it make sense to allow the factory to pay for clean up at a remote lake across the state instead of cleaning up their local pollution where residents live to address the human health risks it has caused? While it could be argued that cleaning up polluted water anywhere is good policy, the public health benefits of one choice could vastly outweigh the public health benefits of the other.

It is exactly this kind of scenario – forgone benefits and lost opportunities – that "blind" carbon markets could create when the consideration of hazardous pollutants that are emitted alongside greenhouses gases are left out of the policy equation.

Why California Must Mind the Climate Gap

While reducing greenhouse gases will help to counter global climate change and in turn benefit all Californians, a carbon market that does not prioritize reductions at sources that also emit hazardous air pollution in populated neighborhoods is likely to result in significant lost public health opportunities – especially for California's most vulnerable populations.

Not all greenhouse gas emitting facilities pollute equally, nor are they evenly distributed statewide. A relatively small number, clustered in densely populated low-income communities and communities of color, are responsible for the vast majority of the combined toxic air pollution from these facilities in such neighborhoods. They account for virtually all of the pollution disparity, under a measure developed in this report, from facilities that will be first to enter the carbon market. This means that increases in emissions among this small group of facilities, or a failure to reduce pollution in step with the declining greenhouse gas emissions cap, could widen the climate gap and weaken the public health goals of California's climate policies.

Fearing this scenario, advocates from impacted neighborhoods have raised significant concerns about the potential results of what seems to be California's likely adoption of a cap-and-trade approach. This report provides evidence to justify these concerns, and also offers a menu of solutions for developing an equitable system that could provide the most long-term benefits to the greatest number of Californians.

Maximizing Benefits for All Californians

Ensuring that California gets the maximum benefit for its carbon reduction efforts is important for public health, our struggling economy, and the reduction of healthcare costs. Although we do not quantify here

the economic impact of health problems caused by toxic air pollution in California, other research has demonstrated that such costs are externalized by major polluters who shift the burden onto California taxpayers and insurance companies. Recent studies suggest that a greenhouse gas reduction strategy that also prioritizes reducing toxic air pollution would result in improved air quality that enhances the overall benefits, compared to a plan that considers only carbon emissions.

This report presents a menu of policy options for how California can implement climate policy in such a way that Californians get more for their initial taxpayer investments. Stressing how to maximize gains is important given that there are some political and economic actors calling for delays in the implementation of AB 32. Out-of-state oil companies, for example, have already begun bankrolling efforts to halt the recent progress California has made on its climate legislation. Two large funders of the anti-AB 32 initiative, Texas-based companies Valero Energy Corp. and Tesoro Corp., both operate facilities which, out of those that will be regulated under AB 32, are among the most responsible for both overall potential health impacts and disproportionately polluting neighborhoods of color and the poor.

Amid industry cries for postponing implementation of California's climate legislation, taking account of the total added economic and health rewards for Californians should be a top regulatory priority.

Closing the climate gap is also key. AB 32 requires consideration of "direct, indirect, and cumulative emission impacts from these GHG reduction mechanisms, including localized impacts in communities that are already adversely impacted by air pollution." It further requires that measures to reduce emisions are designated in a way that "maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to

Tesoro Wilmington Refinery, September 25, 2009

AB 32 and Its Discontents

The current efforts to suspend AB 32, if successful, may create lost opportunities to clean up California's dirty air. Two of the major contributors to that campaign, Texas oil companies Valero and Tesoro, together operate four major refineries in the state – the sector found in this study to pose the greatest local pollution burden on all communities, but particularly low-income communities and communities of color.

Further analysis reveals that these two oil companies are leading contributors to pollution-induced health problems and the state's dirty air disparity. Both operate facilities that are among the worst ten percent of all facility-level health impacts using a health impacts index that was calculated for all facilities following the measure indicated in Bailey et al. (2008) and are on the top ten list of worst contributors to the disparity index developed in this study. If we group refineries in California by company, Tesoro ranks worst in health impacts among all companies with refining operations in the state.

Tesoro also ranks second among the seven major refining companies in California in the ratio of particulate matter that accompanies their GHG emissions, and the ratio of potential health consequences to GHG emissions. This suggests that reducing GHG emissions at these sort of facilities could do more to clean up California's air than reducing the same amount of GHG emissions at other facilities.

The current approach to implementation of AB 32 may need some tweaks to better protect the most vulnerable communities. If, however, implementation of AB 32 is blocked or delayed, all Californians and particularly low-income communities and communities of color will lose out on potential health benefits.

improve air quality." If regulators meet such legal obligations of AB 32 and implement the legislations as intended, more Californians are likely to support taking action now and all Californians will receive the benefits of these investments.

Analyzing Major Polluters to Prevent Unintended Consequences

This report looks at the most significant GHG-emitting facilities (power plants, petroleum refineries and cement kilns) in California and identifies the local burden to people from the accompanying hazardous pollution. While the analysis builds on earlier research by the Natural Resources Defense Council on the overall burden from these facilities, this is the first report of its kind to explicitly consider the demographic disparity in that burden and the implications for carbon market strategies. To do this, we use maps and geographic analysis of the racial, ethnic, and economic character of the surrounding neighborhoods to quantify which populations are currently suffering the most from these facilities' harmful emissions, and therefore have the most to gain from a smarter approach to reducing carbon.

Without knowing how many allowances will be auctioned, at what price, and to which sectors, it is not possible to forecast exactly what trades could occur. Similarly, it is hard to estimate cost curves for every facility to be regulated and use those estimates to predict whether a firm will choose to pay a carbon fee or instead reduce production or engage in technological improvements. And even if all such information were known, any prediction would be error prone given the level of flexibility that would be required of any market that is likely to take effect, making it especially important to include measures to guard against inequitable outcomes.

Given the uncertainty, this report instead identifies the contribution to air pollution from these facilities in surrounding neighborhoods and uses the demographics of the neighborhoods to calculate

disparities in those emissions; it examines the potential negative outcomes that could result from trading among these facilities; and it proposes policy options for an efficient greenhouse gas reduction strategy that would maximize public health and provide the greatest overall benefits to California.

The analytics to do this are complex in their details but relatively straightforward to explain.

First, we identified the most significant facilities by looking at the California Air Resource Board's (CARB) first annual data release under the state's mandatory GHG Reporting Program and combining this information with data on other pollutant emissions, such as PM_{10}. Second, we undertook an extensive process to locate the facilities by cross-referencing several databases and then conducting visual checks with satellite imagery (see Figure 1 for the resulting map and the appendix for more on the method). Third, we used a series of proximity analyses based on a range of distances from half a mile to six miles (the latter distance is perhaps too generous but it is the benchmark used by the California Energy Commission in its environmental justice analysis of any proposed location for a power plant) around each facility. The proximity analyses were used to determine which communities might be affected by emissions and to consider the varying demographics of the communities. Finally, we calculated a pollution disparity index for each facility – a measure of the extent to which a facility disproportionately pollutes people of color as compared to non-Hispanic whites – based on both its pollution level and the local demographics (see

Figure 1: Major GHG-Emitting Facilities in California

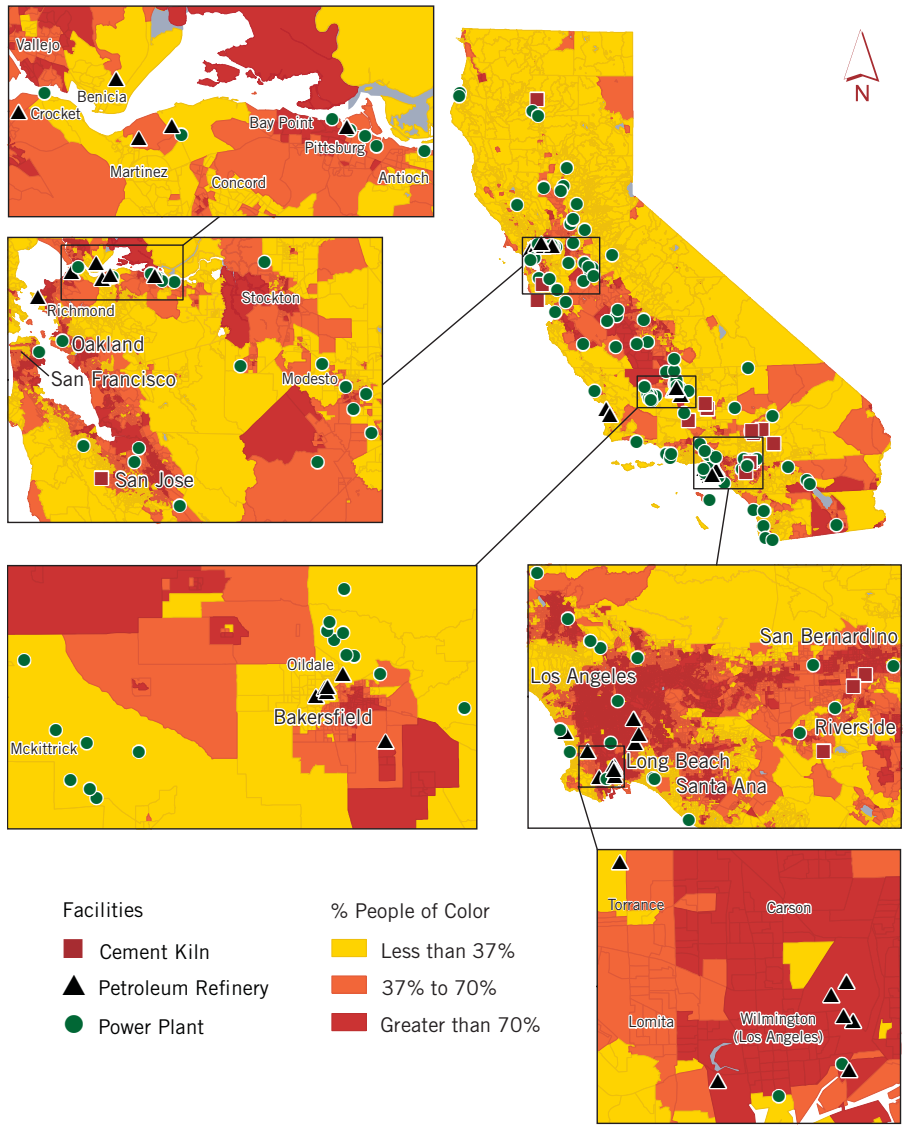


Figure 5 for a description of the pollution disparity index).

The resulting dataset allowed us to examine several issues. In particular, the individual disparity indices could be added up to calculate the statewide disparity score to assess the overall statewide gap in proximity to pollution. And because we had the individual facility data, we could also ascertain the contribution to that overall gap of any particular facility as well as the relative contribution of the major sectors to be regulated.

Figure 2: Percentage Households Within 2.5 Miles of any Facility by Income and Race/Ethnicity in California

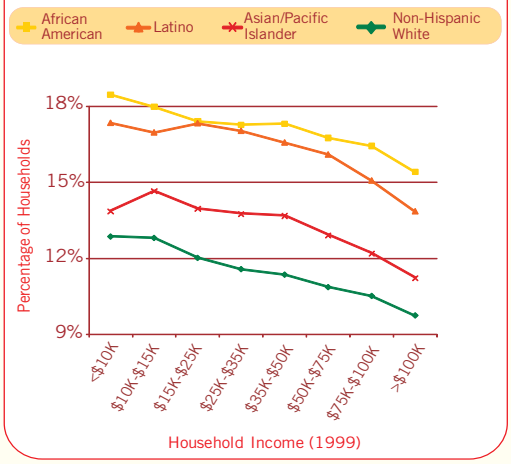


Figure 3: Population-Weighted Average Annual Particulate (PM_{10}) Emissions Burden (Tons) by Race/Ethnicity for Facilities within 2.5 Miles

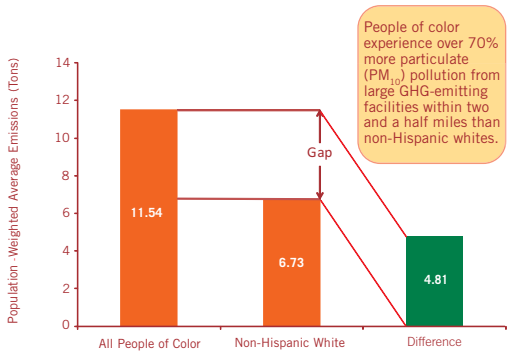
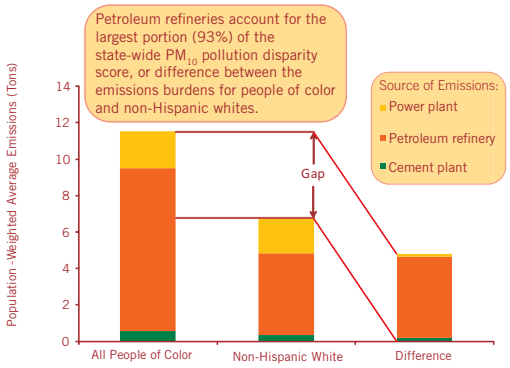


Figure 4: Population-Weighted Average Annual Particulate (PM_{10}) Emissions Burden (Tons) by Facility Category and Race/Ethnicity for Facilities within 2.5 Miles



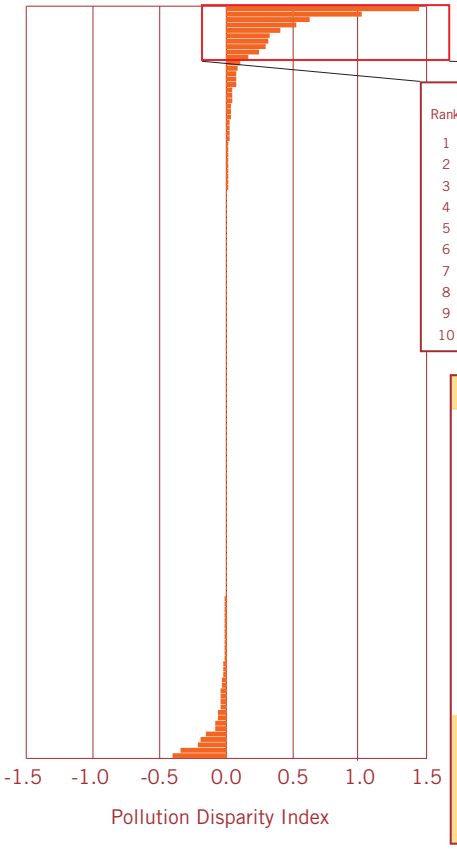
We find the following:

- While the composition of neighborhoods more than six miles away from any large GHG-emitting facility is 54 percent non-Hispanic white and 46 percent people of color, neighborhoods that are closer – within various distance bands such as six miles, two and a half miles, or one mile – are about 40 percent non-Hispanic white and 60 percent people of color.
- Children in poverty, along with all people in poverty, are also disproportionately near major GHG-emitting facilities. However, it's not just this income factor driving the apparent racial disparity: people of color are more likely to live near these facilities than their white peers in the same income bracket (see Figure 2).
- Within California, people of color are more likely to be near those large GHG-emitting facilities with the highest emissions of other pollutants such as particulate matter and/or clusters of facilities where such pollutants accumulate to high levels. Overall people of color experience over 70 percent more particulate matter emissions within two and a half miles from the facilities listed as major GHG emitters as non-Hispanic whites, and the disparity is particularly sharp for African Americans.
- As noted, to quantify the gap more exactly in terms of sectors and individual facilities, we created a pollution disparity index to capture racial disparity in PM_{10} emissions at the facility level based on combining particulate matter emissions with an analysis of the population living within certain distances of the facilities in question. Figure 3 provides one visual representation of the overall gap (or statewide disparity score), which can be derived by adding up the pollution disparity index across all facilities and is equal to the difference in emissions burden borne by people of color and non-Hispanic whites

in California. While we focus on racial disparities here, the same sort of analysis of income disparities leads to similar conclusions.

- Petroleum refineries, a major source of greenhouse gases, are also a leading contributor of other pollutants, such as PM_{10}. Figure 4 breaks the burdens and difference in burdens by source type for people of color and non-Hispanic whites in California; as can be seen, refineries account for a large portion of the pollution burden faced by all people statewide, and contribute even more to the racial disparity in pollution burden – or the difference in PM_{10} emissions burden by race/ethnicity.
- The relative importance of refineries in this pattern may be surprising given that there are more electrical power plants statewide, and cement kilns (which are the fewest in number) generate the most pollution per facility. However, petroleum refineries contribute most to the disproportionate burden partly because they are most likely to be sited in densely populated communities of color.
- If we rank all the facilities in California by their individual pollution disparity indices, we find that the top ten facilities (eight refineries, one power plant, and one cement kiln) are responsible for the vast majority of the air pollution disparity by race/ethnicity (see Figure 5) , due in part to their location proximate to communities of color (see Figure 6).
- What this means is that if facilities in this top ten are allowed to avoid actual emissions reductions by procuring an inordinate share of allowances

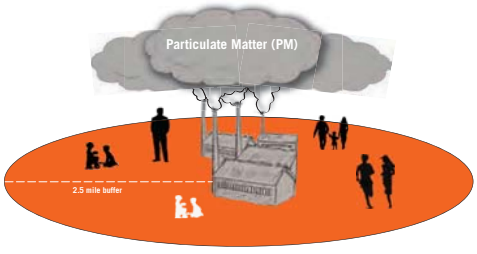
Figure 5: Distribution of the Pollution Disparity Index for PM_{10} at 2.5 Miles Across All Major GHG-Emitting Facilities



Top 10 Facilities Polluting Disproportionately in Communities of Color

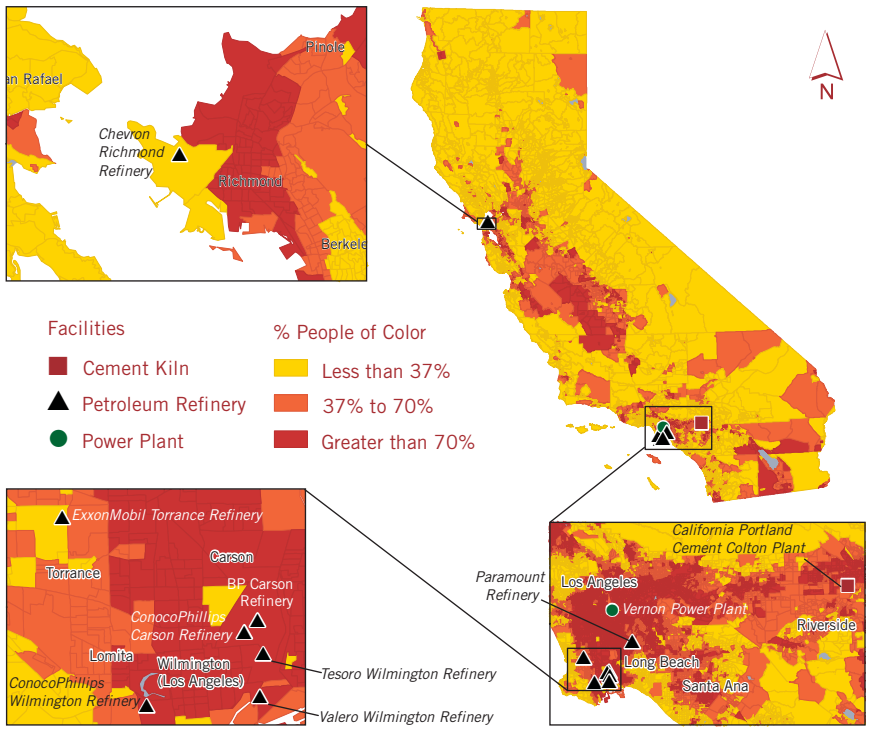
Rank	Facility Name	City	Pollution Disparity Index
1	BP Carson Refinery	Carson	1.44
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)	1.01
3	Paramount Refinery	Paramount	0.62
4	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)	0.52
5	ExxonMobil Torrance Refinery	Torrance	0.40
6	Chevron Richmond Refinery	Richmond	0.32
7	Malburg Generating Station (Vernon Power Plant)	Vernon	0.31
8	ConocoPhillips Carson Refinery	Carson	0.29
9	Valero Wilmington Refinery	Wilmington (Los Angeles)	0.24
10	California Portland Cement Company Colton Plant	Colton	0.16

Calculation of the Pollution Disparity Index



The pollution disparity index measures the extent to which a facility disproportionately pollutes people of color as compared to non-Hispanic whites. It is calculated by considering total pollutants produced by the facility (tons of particulate matter), the number of people within a certain distance of the facility, and the demographics of that population. The resulting disparity index can be added up across all facilities to get the state-wide disparity score – or gap – in pollution burden by race/ethnicity.

Figure 6: Map of Top Ten Facilities in Pollution Disparity



during allowance allocations, paying fees, or trading their way out of reductions, the current pattern of inequity could worsen. On the other hand, minimizing allocations and purchases of allowances and incentivizing actual reductions among these particular facilities could go a long way towards erasing pollution disparities and maximizing the public health benefits of AB 32.

- While there are legitimate concerns about outcomes resulting from allowance distribution and trading *within* a sector – such as when a power plant located near a large population in a low-income community of color eschews GHG reductions in favor of buying credits from another power plant located in an unpopulated area – the most harmful impacts on public health and fairness are more likely to result from the distribution of allowances and trades *between* sectors.
- In particular, because much of the pollution disparity we identify is due to refinery emissions, allowing such refineries to trade or pay their way out of local GHG emissions reductions could leave potential equalizing benefits on the ground.

The Policy Opportunities: Closing the Climate Gap

How do we turn this problem of unequal pollution burden into an opportunity for improving environmental equity and public health? How could a GHG reduction strategy maximize opportunities to

clean up dirty air, reduce healthcare costs, decrease pollution burden disparities, and build support among more Californians for taking action on climate change without delay?

When thinking through policy opportunities, it is important to realize that the potential disparities we discovered would be part of any market system, including the carbon fee strategy favored by some opponents of cap-and-trade. While fees may be better than cap-and-trade for other reasons, one system allows polluters to *pay* their way out of local GHG emissions reductions while the other allows them to *trade* their way out – thus, the disparity and health issues we raise are important for advocates from various sides of the regulatory debate over how to incentivize real greenhouse gas reductions where they are most needed.

The menu of market-based and regulatory approaches below outlines strategies to prevent the concentration of more air pollution in climate gap neighborhoods *and* maximize the health benefits for all Californians.

Necessary Components for Any Market System

A crucial prerequisite to adopting any GHG reduction system is the need for the California Air Resources Board to create a mechanism for monitoring allowance allocations and trades or fee payments. Any framework developed to reduce each facility's carbon output below a target level should also assess the impact of associated pollutants emitted from those same smokestacks.

Policy Options

One solution would be assigning a price to co-pollutants. By raising carbon fees (or making emissions allowances more expensive) in areas with the greatest concentrations of both co-pollutants and people, polluters would have a financial incentive to reduce emissions where health benefits could be maximized. The challenge here is the added complexity in developing a trading or fee system in which allowances or fees must factor in co-pollutants and population densities instead of just homogenous units of carbon. A simpler approach might be to vary permit prices (or fees) by the average relationship between co-pollutants and GHGs in different sectors, but this is would be highly inefficient due to not considering the substantial variation in marginal health co-benefits from GHG reduction that appears to exist at the facility level.

The four options described below might be easier to implement.

Option 1: Restrict Allowance Allocations and Trading or Fee Options Among the Worst Offenders

The full report summarized here identifies the facilities that emit the most significant amount of GHGs along with the air pollution that contributes significantly to California's pattern of environmental disparity. This small number of facilities could be required to reduce emissions locally to meet their contribution to achieving the statewide carbon cap, rather than essentially paying others to reduce through either purchasing (or otherwise acquiring) allowances at allowance auctions (or other forms of allowance allocation), buying them from other facilities through trading, or relying on what are known as "offsets" – basically projects or activities that yield a net GHG emissions reduction for which the ownership of the reduction can be transferred (e.g. slowing deforestation somewhere across the globe). In a fee system, these facilities could be restricted in their capacity to pay fees rather than change operations.

Option 2: Create Trading Zones

Drawing zones that limit trading based on whether the surrounding neighborhoods are currently suffering from extremely poor air quality is a strategy that has already been tested in California. As Kaswan (2009) suggests, certainty in achieving actual reductions in prioritized areas would also largely depend on how allowances were distributed with trading playing a small role, for example, if facilities are able to purchase all the allowances they need for any compliance period at auction or if they are able to rely on offsets to make up the difference between allowance holdings and emissions. While geographic restrictions on trading, allowances, and offsets do impose a layer of complexity, they are an objective and evidenced-based mechanism to create incentives for facilities located in dirtier air zones to reduce emissions, thus maximizing local benefits.

Option 3: Use Surcharges to Improve Highly Impacted Areas

A third strategy involves the imposition of surcharges on allowances in highly polluted neighborhoods, with the funds being returned for environmental and other mitigations in those same areas. This establishes a tight connection or "nexus" between the pollution sources and payments for affected areas. It also lifts up the principle of "cumulative impacts" – that is, that special efforts should be made in areas with multiple sources of pollution.

Option 4: Create a Climate Gap Neighborhoods Fund (also known as a Community Benefits Fund)

In this scenario, neighborhoods with the dirtiest air and/or significant socio-economic challenges would have access to a share of any revenue generated from a carbon fee or carbon allowances to reduce air pollution and invest in other climate mitigation strategies. While the geographic nexus between the emitters and the communities receiving benefits is somewhat looser in this scheme than in the surcharge approach, it may be a more efficient and more widely accepted path to protecting the people already breathing the dirtiest air in California's most impacted and vulnerable neighborhoods.

Avoiding Unintended Consequences and Seizing Opportunities

While it is not possible to predict the exact outcome of any market system for carbon reduction in California, it is likely that one based solely on decreasing greenhouse gas emissions will, at a minimum, fail to realize the full benefits of reduced air pollution and, at a maximum, worsen current patterns of inequality.

It is essential to ensure that any market-oriented regulatory system – either cap-and-trade or fees – avoids concentrating more air pollution sources in communities already breathing the dirtiest air. This report identifies four relatively simple and easy-to-implement policy strategies to avoid unintended health consequences and take advantage of the hidden opportunities:

1. Restrict allowance allocations, trading and offset use – or fee options – among facilities responsible for the worst health impacts.
2. Create trading zones to incentivize pollution reduction in the areas with the dirtiest air.
3. Use revenues to improve air quality in highly polluted areas and enhance the ability of local residents to adapt to climate change impacts.

4. Create a climate gap neighborhoods fund to protect California's most vulnerable neighborhoods.

Most important will be the development of a monitoring system that tracks allocations and trading of allowances and use of offsets (or fee payments) to ensure that such a system does not exacerbate the inequities depicted here, and to enable other mitigation policies to be triggered as needed. This system could also incorporate the impacts from other facilities and sources and allow for the analysis of the "direct, indirect, and cumulative impacts…on communities that are already adversely impacted by air pollution" as called for in the legislation.

In order to successfully confront the climate change challenge, policymakers need to develop a system that will work and that Californians will support. As *Minding the Climate Gap* demonstrates, GHG reduction policies that maximize public health and economic benefits are not only efficient and sensible, but could be relatively simple to implement.

California faces a big challenge but also a big opportunity. We are poised to lead not only in curbing climate change, but also in closing the climate gap. As other states and the nation move forward, the impact of this work will multiply. We should get this right – and fair – from the beginning.

Methodology

This report builds on earlier work by Diane Bailey, Kim Knowlton, and Miriam Rotkin-Ellman (in a 2008 report entitled *Boosting the Benefits: Improving Air Quality and Health by Reducing Global Warming Pollution in California* that was released by the Natural Resources Defense Council). Their report sought to understand the aggregate health impacts of facilities likely to be regulated under AB 32; we sought to look at disparate impacts, which required highly accurate locational data as well as up-to-date emissions data.

We used 2008 GHG emissions data from CARB's first annual release under the state's mandatory GHG Reporting Program and PM_{10} and NO_x data from the 2006 CARB Emissions Inventory for stationary sources. Facility locations were determined by cross-referencing the facility names and addresses given by CARB Emissions Inventory with data from the GHG Reporting Program, a power plants database maintained by the California Energy Commission, and a dataset of facility locations from the U.S. Environmental Protection Agency (EPA), which provided geographic coordinates in addition to addresses. We followed this with a visual locational check using aerial imagery in Google Earth, and, in some cases, following up with web-research on location, including official documentation (reading permit history, for example) and phone calls to parent companies.

Because in-depth emissions modeling was beyond the scope of this effort, we determined affected communities by drawing buffers of different sizes from the facility's point location. We started with the smallest unit of Census geography, the block, and considered whether the center of that block fell into a designated buffer; we then population-averaged up to the block group (a geographic unit that is smaller than the a census tract) because this was the most geographically compact level at which detailed income information was available. Multiple buffers were used to ensure that the patterns we found were not being distorted by buffer size choices. We then developed a series of pollution disparity indices that took into account both population and pollution; in the full report and in the discussion in this summary, we confine our attention to PM_{10} because the results for NOx are similar and we focus on a 2.5 mile buffer because those results were most correlated with the results from an air basin wide health impacts index developed by Bailey and her colleagues and also used here.

References

References are available in the full report which is available at:

http://college.usc.edu/pere/publications

About the Research Team

DR. RACHEL MORELLO-FROSCH is Associate Professor in the Department of Environmental Science, Policy and Management and the School of Public Health at the University of California, Berkeley. Dr. Morello-Frosch's research examines race and class determinants of environmental health among diverse communities in the United States. A focus of her work is the relationship between segregation and environmental health inequalities associated with air pollution, children's environmental health, and the intersection between economic restructuring and community environmental health. Currently, Dr. Morello-Frosch collaborates with colleagues and environmental justice organizations to research and address climate justice issues, including the social equity implications of proposed greenhouse gas reduction strategies in California associated with the AB 32 Scoping Plan; and disparities in community capacity to adapt to environmental impacts of climate change. Her work is funded by the National Institutes of Health, the National Science Foundation, the California Environmental Protection Agency, the California Wellness Foundation, and the California Endowment, among others. Dr. Morello-Frosch currently serves on the Health Impacts Assessment Advisory Committee for the implementation of the AB 32 Scoping Plan.

DR. MANUEL PASTOR is Professor of Geography and American Studies & Ethnicity at the University of Southern California where he also serves as Director of the Program for Environmental and Regional Equity (PERE) and co-Director of USC's Center for the Study of Immigrant Integration (CSII). Pastor holds an economics Ph.D. from the University of Massachusetts, Amherst, and has received fellowships from the Danforth, Guggenheim, and Kellogg foundations and grants from the Irvine Foundation, the Rockefeller Foundation, the Ford Foundation, the National Science Foundation, the Hewlett Foundation, the MacArthur Foundation, the California Environmental Protection Agency, the California Wellness Foundation, and many others. His most recent book, co-authored with Chris Benner and Martha Matsuoka, is *This Could Be the Start of Something Big: How Social Movements for Regional Equity are Reshaping Metropolitan America* (Cornell University Press, 2009). Dr. Pastor served on the Regional Targets Advisory Committee, a group advising the California Air Resources Board on methods to set goals for the reduction of greenhouse gas emissions through better land use planning.

DR. JAMES L. SADD is Professor of Environmental Science at Occidental College, Los Angeles, California. He earned his doctorate in geology at the University of South Carolina, Columbia. His research includes spatial analysis using geographic information systems and remote sensing tools, particularly to evaluate questions related to environmental exposure. His recent research is supported by contracts and grants from the Andrew W. Mellon Foundation, US Army Corps of Engineers, US Navy Office of Naval Research, NOAA SeaGrant. Dr. Sadd served on the Nationally Consistent Environmental Justice Screening Approaches Work Group, advising on the EPA's Environmental Justice Strategic Enforcement Screening Tool (EJSEAT).

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Minding the Climate Gap Report

EXCERPT CHEVRON RDEIR – Community Greenhouse Gas Reduction Program

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RICHMOND, CA 94804

4.8.4.1.2.3.1 *Chevron Facility Greenhouse Gas Reductions*

Chevron would implement several Project Design Features within the Facility and related Chevron operations to reduce greenhouse gas emissions. The measures include water conservation, light-emitting diode (LED) lighting retrofits, Marin Clean Energy participation, and fluid catalytic cracker cooling water tower motor upgrades. The minimum amount of greenhouse gas reductions to be achieved by these Project Design Features is 1,312 MT CO_2e/year. All reductions would be monitored for verification.

The water conservation measures would reuse stripped sour water in the distillation and reforming area and the South Isomax area. The reuse of water in these areas would result in greenhouse gas emission reductions of 109 MT CO_2e per year. LED lighting retrofits of approximately 6,000 lighting fixtures would result in greenhouse gas emission reductions of 339 MT CO_2e per year. Participation in Marin Clean Energy would reduce greenhouse gas emissions by 0.3 MT CO_2e per year for commercial accounts and 288 MT CO_2e per year for industrial accounts (assuming industrial account participation in the Marin Clean Energy Program is practicable). Upgrading the motors that drive the fluid catalytic cracker cooling water tower to be more energy efficient would reduce greenhouse gas emissions by 576 MT CO_2e per year. *Appendix 4.8-COP* has more details on how the conservative greenhouse gas emission reductions were estimated.

Air quality impacts of construction of the water conservation measures, LED installations and fluid catalytic cracker motor upgrades are discussed in *Appendix 4.3-CST*. The aesthetic impact of LED lighting is discussed in Section *4.1, Aesthetics, Visual Quality, Light, and Glare*, and the water impact of the water conservation measures is discussed in the *Section 4.9, Hydrology and Water Quality*. Participation in Marin Clean Energy would not result in any direct physical impacts to the environment.

4.8.4.1.2.3.2 *Funding for Community-Based Greenhouse Gas Reduction Programs*

Chevron would fund community-based greenhouse gas reduction programs (CGRPs) to be selected and administered by the City of Richmond, with input from community stakeholders in the City and North Richmond, and Chevron, as described below. Potential CGRPs are identified below and further described in *Appendix 4.8-CGRP*. Further CGRPs may also be identified in the future. For

planning purposes, reductions of 5,500 MT CO_2e per year for a period of 10 years, commencing at the start of Project operations, are evaluated.[9] Should greenhouse gas annual reductions from the CGRP fall short of this planning level, Chevron has agreed to purchase additional cap and trade allowances as needed to achieve its NNI Project objective.

To fund the selected CGRPs, Chevron would deposit $3 million annually for 10 years with the City, with the initial payment due at the commencement of Modernization Project construction. The City would draw upon this amount to administer and fund the implementation of the CGRPs. City administrative costs would not exceed 15% of the cost of the CGRPs implemented on an annual basis.

Several criteria were considered in evaluating the CGRPs from which the City may select for implementation:

- **Cost effectiveness** – The cost effectiveness of measure in terms of cost per MT of greenhouse gas emission reductions. Certain measures are more cost effective (i.e., require less money to achieve a certain amount of greenhouse gas reductions) while other measures can be less cost effective (i.e., require more money to achieve a certain amount of greenhouse gas reductions).
- **Local job creation** – The potential for a measure to create or maintain quality local jobs. Jobs are created from construction activities (e.g., energy efficiency retrofit work, installation of solar systems), increased recycling and composting activities, and tree planting and park maintenance activities. In addition, when residents save on energy costs this could translate into additional money to be spent in the community and the creation of additional local jobs.
- **Local greenhouse gas emission reductions** – The magnitude of greenhouse gas emission reductions to be achieved locally through implementation of the measure. Local greenhouse gas emission reductions tend to bring co-benefits to the community compared to greenhouse gas emission reductions that occur remotely.
- **Community health co-benefits** – The potential for a measure to improve community health by improving outdoor and indoor air quality (e.g., from reduced criteria air or toxic air pollutant emissions) and by promoting increased physical activity (e.g., walking or biking).

[9] 5,500 MT CO_2e per year corresponds to the increase in indirect, shipping, rail, and on-road emissions at the 93% Utilization Scenario from Baseline as these emissions are not covered under the cap-and-trade regulation.

- **Community wealth and resilience** – The potential for a measure to create community wealth and resilience (e.g., by reducing energy costs for residents, or enhancing the value of homes or other structures).
- **Other environmental sustainability enhancements** – The potential for a measure to enhance other types of environmental sustainability (e.g., waste diversion to recycling and compost bins, reduced fuel consumption, reduced energy consumption) or provide other environmental co-benefits (e.g., urban greening, habitat creation, improved groundwater quality).
- **Accurate Metric/Verifiable** – The availability of accurate metrics to measure and verify greenhouse gas reductions achieved through implementation of the measure.
- **Magnitude of greenhouse gas reductions available** – The magnitude of local greenhouse gas emissions available to be reduced through implementation of the measure.
- **Leveraging potential** – The potential for leveraging of additional resources (e.g., funds, labor, etc.) for further greenhouse gas emission reductions through program enhancements or expansions.

The CGRPs considered include:

- **Urban Forestry** – Enhance tree planting programs on private property, City parks and City streets. Environmental program benefits include improved air quality and prevention of heat island impacts. Greenhouse gas emissions are reduced through sequestering CO_2 and decreased building energy use due to shading impacts.
- **Zero Waste Programs** – The City has an opportunity to increase the waste diversion percentage from its current 52% to 75% by 2020. This could be achieved by implementing cost effective programs such as free recycling bins to businesses and residents, and providing technical assistance and outreach services to facilitate recycling and composting. Benefits include local job creation and enhanced environmental sustainability.
- **Residential Energy Efficiency Rebate** – Provide home weatherization services and other home performance energy efficiency rebates to incentivize homeowners to improve the energy efficiency on their homes by the state's goal of 40%. Benefits include creating community wealth and resilience through less spending on utilities, local job creation, improved public health, and enhanced environmental sustainability.
- **Commercial Energy Efficiency Rebate** – Provide energy efficiency rebates to Richmond businesses to incentivize energy efficiency upgrades. The rebates would be structured to increase proportionally with greater energy

reductions. Benefits include local job creation and decreased dependence on non-renewable sources of energy.

- **Residential Solar Rebate** – Provide solar rebates to incentivize homeowners to install photovoltaic (PV) panels on rooftops. Residents may leverage rebates from the state and the Marin Clean Energy program to make solar more cost competitive. Benefits include local job creation and decreased dependence on non-renewable sources of energy.
- **Commercial Solar Rebate** – Provide solar rebates to incentivize Richmond businesses to install PV panels. The rebates would be structured to increase proportionally with greater PV installation. Benefits include local job creation and decreased dependence on non-renewable sources of energy.
- **Pedestrian Plan and Bicycle Master Plan Implementation** – Implement bicycle and pedestrian improvements identified in the Pedestrian Plan and Bicycle Master Plan to encourage transportation via bicycle or walking rather than by car. Special attention would be made to focus these improvements in Priority Development Areas, areas expected to accommodate growth, near public transit. Benefits include improved public health through physical activity, contribution to community wealth and resilience through less spending on vehicle fuel, improved public health through fewer vehicle emissions, and decreased dependence on non-renewable sources of energy.
- **Electric Vehicles** – Encourage the purchase of electric vehicles by providing rebates to residents and businesses that install electric vehicles charging stations and/or provide direct rebates for the purchase of electric vehicles. Benefits include contribution to community wealth and resilience through less spending on vehicle fuel, improved community health through fewer vehicle emissions, and decreased dependence on non-renewable sources of energy.
- **Ride Share/Green Transportation** – Encourage the availability of low-greenhouse gas transportation alternatives, such as acquiring an electric bus and charging station for the City, and providing funding to support car-share and shuttle services. Benefits include contribution to community wealth and resilience through less spending on vehicle fuel, improved community health through fewer vehicle emissions, and decreased dependence on non-renewable sources of energy.
- **Bicycle Program** – Develop a bicycle share program that allows for residents to rent bicycles by the hour. Bicycles could be picked up and dropped off at designated secure stations. Benefits include improved public health through physical activity, contribution to community wealth and resilience through less spending on vehicle fuel, improved air quality through fewer vehicle emissions, and decreased dependence on non-renewable sources of energy.

- **Transit Access** – Encourage participation in reduced cost, group purchased, monthly public transportation access (e.g., reduced cost Clipper Card). Benefits include contribution to community wealth and resilience through less spending on vehicle fuel, improved community health through fewer vehicle emissions, and decreased dependence on non-renewable sources of energy. Fund transit stop improvements.
- **Wetlands Creation** – Purchase and restoration of tidal wetlands in Richmond. Benefits include creation of habitats for plant and animal species, stormwater runoff mitigation, erosion control, and improved aesthetics.
- **Chevron Solar Project (2 megawatts [MW])** – Construct a 2-MW ground-mounted PV solar facility on approximately 13 acres of Chevron property, comprised of approximately 7,800 PV solar panels, each rated at 295 Watts. It would be located adjacent to Castro Street near the intersection with Richmond Parkway (Chevron Data Transmittal #43, 2013), as shown in Figure 4.8-1. The use of this property for solar power generation would constitute a beneficial re-use of a brown field site. The projected energy output would be 3,800 megawatt-hours per year, which would supply the northern California electrical grid (Chevron Data Transmittal #69, 2014). This would constitute a reduction of approximately 644 MT CO_2e per year from non-renewable power generation using conservative emission factors.[10] Greenhouse gas emission reductions could be as high as 1,629 MT CO_2e per year depending on how PG&E reduces its greenhouse gas intensity to meet the Renewables Portfolio standard. This would be partially funded by the CGRP. The difference would be funded directly by Chevron.
- **Climate Action Plan Implementation** - Additional reduction measures identified in the City of Richmond Climate Action Plan when the plan is finalized, consistent with the prioritization criteria.

Table 4.8-5 provides estimates of reductions from the CGRPs given an illustrative distribution of $30,000,000 across the programs over time. A description of all CGRPs along with a corresponding quantification of emission reduction estimates, is included in *Appendix 4.8-CGRP*.

4.8.4.1.2.3.2.1 *Environmental Impacts of CGRP Implementation*

CEQA requires that the potentially significant adverse environmental impacts of Project Design Features, as well as mitigation measures, also be considered, and

[10] This was conservatively calculated using an emission factor projected for 2016 (370 pounds per megawatt-hour) and the CH_4 and N_2O emission factors reported by CARB (PG&E, 2013; CARB, 2010).

TABLE 4.8-6 CGRP MEASURES AND PRIORITIZATION CRITERIA

	Measure	Cost Effectiveness ($/MT CO2e)	Create Local Jobs	Reduce Local Greenhouse Gas Emissions	Improve Community Health	Create Community Wealth & Resilience	Enhance Other Environmental Sustainability	Accurate Metric/ Verifiable	Magnitude of Greenhouse Gas Reduction Available	Leveraging
Urban Greening	*Urban Forestry:* Plant trees to help sequester CO_2.	$58	✓	✓	✓	✓	+	✓	✓	—
	Pedestrian and Bicycle Master Plan implementation: Development of bicycle and pedestrian networks.	$22	—	✓	✓	✓	✓	—	✓	—
	Zero Waste Programs: Increase the waste diversion by implementing programs to encourage recycling and compost.	$4	✓	✓	—	—	✓	✓	✓	—
Energy Efficiency	*Healthy Homes/Residential Energy Efficiency (Any Income):* Provide home performance energy efficiency (weatherization) rebates.	$35	9.7 jobs /$1M[1]	✓	✓	✓	✓	✓	+	✓
	Healthy Homes/Residential Energy Efficiency (Low Income): Provide home performance energy efficiency (weatherization) rebates for low income households.	$71	9.7 jobs /$1M[1]	✓	✓	+	✓	✓	✓	✓
	Residential Solar Rebate: Incentivize homeowners to install PV panels through rebates.	$278	9.7 jobs /$1M[1]	—	—	✓	✓	✓	✓	✓
	Commercial Energy Efficiency: Incentivize business owners to increase energy efficiency.	$7	9.7 jobs /$1M[1]	✓	—	✓	✓	✓	+	—
	Commercial Solar Rebate: Incentivize business owners to install PV panels through rebates.	$69	9.7 jobs /$1M[1]	—	—	✓	✓	✓	✓	✓

TABLE 4.8-6 CGRP MEASURES AND PRIORITIZATION CRITERIA

	Measure	Cost Effectiveness ($/MT CO2e)	Create Local Jobs	Reduce Local Greenhouse Gas Emissions	Improve Community Health	Create Community Wealth & Resilience	Enhance Other Environmental Sustainability	Accurate Metric/ Verifiable	Magnitude of Greenhouse Gas Reduction Available	Leveraging
Transportation Greenhouse Gas Reduction Measures	*Electric Vehicle Purchase Rebates:* Encourage purchasing of electric vehicles by providing rebates to residents purchasing electric vehicles.	$15	—	✓	✓	✓	✓	✓	+	✓
	Electric Vehicle Charging Stations Rebates: Encourage use of electric vehicles by providing rebates to businesses that install electric vehicle charging stations.	$85	—	✓	✓	✓	✓	✓	✓	—
	Ride Share/Creen Transportation: Encourage the availability of low-greenhouse gas transportation alternatives, such as local shuttle circular and van service, and the acquisition of an electric bus.	$358 - $2,788	✓	✓	✓	✓	✓	—	+	✓
	Bicycle Program: Develop a public bicycle sharing system.	$611	—	✓	✓	✓	✓	—	✓	—
	Transit Access: Encourage participation in reduced cost monthly public transportation access (e.g., reduced cost Clipper Card).	$521	—	✓	✓	✓	✓	—	✓	✓
Other	*Wetlands:* Create wetlands in the City of Richmond for carbon sequestration.	$7K - $45K	—	✓	—	—	+	✓	✓	—
	2-MW Solar Project: Construct a 2-MW PV solar facility on the Project site that supplies the electric grid.	$328	✓	✓	✓	✓	✓	+	✓	✓

• Jobs per million dollars metric obtained from RIMS 2010 Data for Construction Industry in Contra Costa County.

Comments on the Chevron RDEIR:

A Feasible Alternative to the Project would provide firm, specific, local Greenhouse Gas Reductions, and this would be Environmentally Superior

Regarding the Chevron Richmond Refinery Proposed Revised Project City of Richmond Planning Department File PLN11–089

Revised Draft Environmental Impact Report (RDEIR)
State Clearinghouse No. 2011062042
Released March 2014

Submitted on behalf of
Communities for a Better Environment (CBE)
By Julia May, Senior Scientist

May 2, 2014

CONTENTS:

The Project Must Provide Firm, Specific, Local Greenhouse Gas Reductions

This comment identifies alternative local, community-based solar and related clean energy projects that are feasible, achieve higher reductions, and would result in an environmentally superior project.

A. Good potential programs are identified in the RDEIR, but there is currently no commitment to any local Community-Based Greenhouse Gas Reduction Program, and the main proposal using carbon trading has many potential impacts that cannot be mitigated

The Chevron Revised Draft Environmental Impact Report (RDEIR) provides a fair amount of good information on innovative Community-Based Greenhouse Gas Reduction Programs (CGRPs), in line with ideas proposed by the community during the earlier Chevron EIR process. Unfortunately, there is no commitment made in the RDEIR to carry out any of these proposals. The RDEIR states that CGRP reductions are examples, and if not carried out, they will be replaced with cap-and-trade allowances. An environmentally superior alternative project would provide firm, specific, local reduction commitments at higher levels while improving the local economy.

A major caveat, as described below, however, is that even these CGRPs cannot entirely mitigate the negative impacts of the Project. Even if all the CGRPs were implemented using an example case in the RDEIR (for 5,500 metric tonnes of CO2 equivalent reduction (MTCO2e)), this is a very small program sum compared to the total increased Greenhouse Gases (GHGs) identified for the Project (725,579 MTCO2e).

At the outset, it should be noted that the project is fundamentally problematic. The expansion of fossil fuel production proposed at the refinery uses worsening feedstocks such as higher sulfur crude and gas oils, resulting in major increases in greenhouse gases and other impacts. Chevron's GHG emissions are already very high.

Therefore, this Project proposes a worse than business-as-usual scenario, counter to our need to transform the energy sector away from harmful fossil fuels. It is necessary due to approaching catastrophic climate change to avoid these increases, and this is counter to California's goals. It is also necessary to avoid increasing dangerous conditions such as corrosion caused by sulfur contamination in feedstocks that was a cause of the August 2012 Chevron explosion found by the U.S. Chemical Safety Board. To the extent that laws *allow* this worsening of energy production in oil refineries, this comment attempts to *mitigate* a portion of it, but cannot entirely prevent such harms.

<u>Negative impacts of the current proposal to offset greenhouse gas increases</u>

The Project will have direct negative greenhouse gas-related impacts not identified in the RDEIR, and many characteristics of the CGRP program render it ineffective:

- **The Project CGRPs are listed as only *potential* measures**, with details to be

determined later, and no firm commitment to *any* CGRPs, which may be replaced with cap-and-trade allowances.

- **The Project relies on cap-and-trade allowances not required to be local for at least 99% of GHG reductions.** While the RDEIR states that the CGRPs should support local jobs and GHG reductions, relying on at least 99% cap-and-trade allowances is counter to this.
- **A regional urban CO_2 dome to which the Project will contribute is not mitigated by using cap-and-trade allowances.** The CO2 dome has the potential to increase death rates caused by smog, and these impacts would not be offset by global cap-and-trade credits or offsets. A Stanford study[1]reported that increased CO2 concentrations (long known to exist over cities) can locally increase smog formation and cause local temperature increases, leading to higher death rates. The RDEIR found that the Project GHG emissions before mitigation are significant, so offsetting emissions that contribute to the regional CO2 dome effect by purchasing cap-and-trade allowances, means that the local dome effect should be considered an unmitigated potential significant impact.
- **Cap-and-trade allowances and offsets themselves can cause direct impacts that have been widely documented, on forests, industrial sites, etc.** These include potential impacts from replacing old growth forest with monoculture plantations, incentivizing coal mining through mining methane capture offsets, and others. (See below)
- **Chevron's plan to use cap-and-trade exports jobs out of Richmond and the country, counter to a City of Richmond resolution.** The RDEIR states that the City of Richmond earlier asked that the Chevron Project support local jobs to *"Increase economic welfare in the Richmond area by creating construction jobs and employing local residents."*[2] The RDEIR also states that Chevron modified the Project in response to this resolution. But Chevron's proposal to mitigate almost 100% contradicts this resolution, because allowances are allowed to be generated across international geographic locations (thus outside the local area). A specific commitment to local projects to offset GHG emissions would instead support the local economy's welfare, and would be located in the area where the Project impacts occur.
- **Local measures are far more verifiable, enforceable, and amenable to meet local community needs** compared to cap-and-trade credits and offsets, which are vulnerable to fraud, and have indirect and unverifiable emissions reduction estimation methods.
- **Chevron's Greenhouse Gas mitigation funding proposal is spread too thin across too many different programs.** This reduces the effectiveness of any of the measures. It would be environmentally superior to have fewer programs with sufficient funding, rather than too many programs with insufficient individual funding to produce results.
- **Local reductions must be evaluated and adopted if feasible under CEQA**. Under CEQA Chevron must identify the significant impacts of the Project, mitigate them if feasible, and adopt the environmentally superior alternative. Chevron must consider an

[1] *Environ. Sci. Technol.* 2010, *44,* 2497–2502, Enhancement of Local Air Pollution by Urban CO2 Domes, Mark Jacobsen, *Stanford University, Accepted March 2, 2010.*
http://www.sciencedaily.com/releases/2010/03/100316101705.htm
[2] DEIR Volume 1 at p. 4.0-7 to 4.0-8

alternative that directly reduces impacts of the Project, increases local offsets, and reduces or avoids using allowances outside of Richmond.

The potential CGRP example includes only a tiny amount of solar and other clean energy generation

The Project discusses an assumption where Chevron operates at an average annual rate of 93% of maximum permitted capacity, under post-Project revised air permit limits,[3] although it also evaluates at a 100% utilization rate, and under other conditions. The RDEIR identifies the GHG emission reductions proposed at the 93% utilization level in Table 4.8-5 as follows, with the local CGRPs providing reductions at 5,500 MTCO2e out of the total 725,579 MTCO2e the RDEIR states is needed:

TABLE 4.8-7 FACILITY PROJECT DESIGN FEATURE EMISSION REDUCTIONS AT 93% UTILIZATION PROJECT SCENARIO

Project	Annual Greenhouse Gas Emission Reduction (MT CO_2e)
Water Conservation	109
LED Lighting Retrofits	339
Marin Clean Energy Participation	288
Fluid Catalytic Cracker Cooling Water Tower Motor Upgrade	576
CGRPs (provided for illustrative purposes only)*	5,500
Cap-and-Trade Allowances	718,767
Total	**725,579**

* Actual greenhouse gas reductions from the CGRP program will vary over time. Chevron is required to purchase additional cap and trade allowances for years in which CGRP program implementation results in less than 5,500 MT of CO2e.

However, the table identifies the CGRP reductions as "for illustrative purposes only," and the asterisk at the bottom of the table states that actual reductions from CGRPs might be less than 5,500 MTCO2e, with the remainder coming from cap-and-trade allowances. So, in fact, there is no commitment in the RDEIR to any portion of even the small commitment of 5,500 MTCO2e reduction through local CGRPs. Instead, the commitment is made to fulfill 99.8%[4] through cap-and-trade alone, plus a small commitment to the 725,579 MTCO2e total (0.07%) through water conservation, LED lighting replacement, and participation in Marin Clean Energy.

[3] DEIR at p. 2-5

[4] 718,767 MTCO2e Cap & Trade allowances + 5,500 MTCO2 potential CGRPs that can be replaced with Cap & Trade allowances= 724,267 / 725,579 = 99.8%

Another table excerpted below (4.8-5) estimates CGRP emissions reductions that might be achieved in the first year of a ten-year potential program, with a higher but still modest reduction level at 9,367 MTCO2e (about 1% of the total greenhouse gas reduction need identified). Local solar included is a very small, token part of this total, with 27 MTCO2e provided through a Residential Solar Rebate, 108 MTCO2e through a Commercial Solar Rebate, and 299 MTCO2e through an onsite Chevron 2 megawatt (MW) solar installation, totaling only 434 MTCO2e solar out of 725,579 MTCO2e, (0.06% of the total GHG reductions needed). Far higher levels of local solar generation are feasible than reflected in the RDEIR CGRP proposal above, and this clean energy generation source will be a major replacement for fossil fuels in the future, and should be promoted (see below). The small reduction levels in the example represent a very low-end extreme in the RDEIR.

TABLE 4.8-5 ESTIMATED EMISSION REDUCTIONS FROM CGRPS IN THE FIRST YEAR (HYPOTHETICAL BUDGET SPREAD)

Program	Annual Greenhouse Gas Emission Reduction (MT CO_2e)[1]
Urban Forestry	130
Zero Waste Programs	2,047
Residential Energy Efficiency Rebate	265
Commercial Energy Efficiency Rebate	903
Residential Solar Rebate	27
Commercial Solar Rebate	108
Pedestrian and Bicycle Master Plan Implementation	3,351
Electric Vehicles	1,039
Ride Share/Green Transportation	590
Bicycle Program	307
Transit Access	360
Wetlands Creation	11
Chevron Solar Projects	229
Total	**9,367**

Note: The emission reductions shown in this table are estimated emissions in the first year assuming funds are spread evenly across all programs. Emission reductions in subsequent years are expected to increase.
Source: *Appendix 4.8-CGRP*.

The RDEIR also chose not to evaluate, dismissing as infeasible, a set of extremely large local solar projects that would cover major tracts of land with panels:

A) Solar Alternative 1: 460 MW over 4.3 square miles of land to displace 100% of the facility's electricity generation by the facility's cogeneration units,[5] and

B) Solar Alternative 2: 2,477 MW over 23.2 square miles to offset 100% of the Project's GHG emissions.[6]

Such massive projects might be extreme, but the RDEIR never evaluated reasonable levels of offsite solar energy in between these low and high extremes, or how to maximize reasonable levels of local solar generation. Evaluating only extremes doesn't fulfill the requirement that the RDEIR seriously evaluate feasible alternatives.

The RDEIR did however evaluate an 8-MW onsite solar facility at Chevron (the "Renewable Energy Alternative"). It was found to be feasible, technologically and commercially viable,[7] but it was illogically dismissed.

Richmond, the Bay Area, and California are nowhere near capacity for solar electricity generation. Although the RDEIR states that Richmond is not ideal for siting solar, many examples of high concentrations of solar installations in places like Germany and parts of the U.S. Midwest contradict this idea.

California's population is 37.7 million. It has only 1,627 MW solar installed (2010)[8] Germany's population is more than double that (81.5 million), but has 15 times the solar installed capacity (about 25,000 MW in 2011).[9] The German government estimated a $5 billion electricity market price reduction caused by renewable energy in 2009.[10] Germany was able to quickly increase solar capacity (installing 7,000 MW/year) at lower average system cost than California, through a carefully devised Feed-In-Tariff program.[11] California rooftops could site 80 GW solar

[5] DEIR at 6-14
[6] DEIR at 6-15
[7] DEIR at 6-14
[8] From CEC - *Renewable Power in California 2010, from Dec 2011 report,* CEC, *Renewable Power in California: Status and Issues,* December 2011, p. 3, http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-150-2011-002-LCF-REV1
[9] *Development of Renewable Energy in Germany in 2011,* Based on Statistical Data of the Working Group on Renewable Energy Statistics (translated from slides: *Entwicklung der erneuerbaren, Energien in Deutschland im Jahr 2011,* Grafiken und Tabellen Stand: März 2012, unter Verwendung aktueller Daten der Arbeitsgruppe Erneuerbare Energien-Statistik (AGEEStat), Erneuerbare Energien in Deutschland, 2011) , Slide 11 – **Contribution of renewable energy to the electricity supply** (Beitrag erneuerbarer Energien zur Strombereitstellung), 2011,Total electricity generation (Summe Stromerzeugung) is 121,939 GWh, Photovoltaik: 19,000 GWh = 15% of total, 2011, Slide 12 - **Installed capacity for electricity from renewable,** Installierte Leistung zur Strombereitstellung aus erneuerbaren, Total Performance: 65,483 MW, Photovoltaik: 24,820 MW, 2011, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CDEQFjAA&url=http%3A%2F%2Fwww.erneuerbareenergien.de%2Ffiles%2Fpdfs%2Fallgemein%2Fapplication%2Fpdf%2Fee_in_deutschland_graf_tab.pdf&ei=RG69UOe7F8LTiwK9u4DoDA&usg=AFQjCNGWfrVXZgEvzGdFOQKXkPVDw4zWuA,
[10] *Prepared Direct Testimony of Bill Powers on Behalf of The California Environmental Justice Alliance Before the Public Utilities Commission of the State of California*, June 25, 2012, R.12-03-014, at p. 24
[11] *Bay Area Smart Energy 2020* (BASE 2020), Bill Powers, P.E., Pacific Environment, March 2012, http://pacificenvironment.org/-1-87, at pp. 2-3.

capacity (or 80,000 MW, which is much more than our peak electricity need), according to an Environment California 2012 report.[12]

It is clear that photovoltaic installations in Richmond can make a far higher contribution to clean energy than is currently the case.

B. An environmentally superior alternative that includes local greenhouse gas reductions and solar should be evaluated and adopted

To address the flaws and impacts identified above, an environmentally superior alternative would:

- Increase local CGRPs, and make a firm commitment to them.
- Add the 8MW solar facility on the Chevron site which the RDEIR identified, but which it inappropriately dismissed simply because it couldn't provide all Chevron's electricity needs, all the time.
- Concentrate funding on fewer types of local green energy GHG projects out of the CGRP list in order to result in reliable emissions reductions with a greater advancement of individual programs rather than tiny improvements to many different programs, or add significant funding.
- Support local jobs and the local economy, consistent with aforementioned the City of Richmond resolution.
- Reduce or avoid a significant increased contribution to the local CO2 dome.
- Avoid the significant potential impacts of cap-and-trade allowances.
- Be locally verifiable and enforceable.
- Bolster a permanent change to the local energy infrastructure that will replace fossil fuel use in the long term.
- Provide benefits of Distributed Generation.
- More fully apply the CGRP criteria[13] identified in the RDEIR (which are now only applied to 0-1% of proposed GHG reductions):
    - Local job creation
    - Local greenhouse gas emission reductions
    - Community health co-benefits
    - Community wealth and resilience
    - Other environmental sustainability enhancements
    - Accurate Metric/Verifiable

[12] CalFinder – Nationwide Home Solar Power Contractors and Information, C*alifornia Reaches 1 Gigawatt of Installed Rooftop Solar Power,* 2011, http://solar.calfinder.com/blog/news/california-reaches-1-gigawatt-of-installed-rooftop-solarpower/

[13] DEIR at p. 4.8-40 to 4.8-41

- Magnitude of greenhouse gas reductions available
- Leveraging potential
- Cost effectiveness

A feasible local solar and electric vehicle combination would bolster permanent energy change

According to the RDEIR, Chevron purchases a net average of 2 MW of *electricity* from PG&E (although it self-generates a much larger amount).[14] However, the purpose of the refinery is to use crude oil and intermediate products to produce transportation and lube oil fuels, so the overall energy use for analysis at Chevron goes far higher than its electricity use.

Furthermore, energy use is trending more and more toward a blending between transportation fuels and electricity generation and use. An important and rigorous study out of UC Berkeley found that in order to meet the State of California's existing goal of 80% GHG reduction by 2050,[15] California must 1) completely phase out fossil-fueled *electricity*, and 2) electrify *transportation*. The study found that this means that oil refineries will need to be phased out over time, electric vehicles will replace gas and diesel powered vehicles, and electricity will need to be generated without fossil fuels. That goal is a long way out, but planning a step-by-step process to meet that goal needs to start now, to be consistent with goals of the State of California. Moving Richmond toward clean electricity and electric transportation in substantial but feasible steps will minimize the disruption during this necessary energy transformation.

Instead of $30 million over 10 years spread between 16 programs, the Chevron funding would be better spent concentrated in fewer areas, or by greatly increasing the funding of all of these programs.

Volume 2 of the RDEIR provided assumptions it used to determine the cost-effectiveness and greenhouse gas reductions of these programs. For the potential solar rebate program, the RDEIR identified the following:

- Potential Chevron rebate of $2000 per kilowatt (KW) of residential rooftop solar.

[14] DEIR at 6-13

[15] *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity*, p. 9, James H. Williams, 1,2, Andrew DeBenedictis,1, Rebecca Ghanadan,1,3, Amber Mahone,1, Jack Moore,1, William R. Morrow III,4, Snuller Price,1, Margaret S. Torn, 3,* 1) Energy and Environmental Economics, 2) Monterey Institute of International Studies, 3) Energy and Resources Group, University of California, Berkeley, 4) Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, Berkeley, CA. Published Online, November 24 2011, Science, 6 January 2012: Vol. 335 no. 6064, available at http://www.sciencemag.org/content/335/6064/53

- Up to $6000 for a typical 3KW system.[16]
- A total of $187,500 per year for this example program for 10 years, and $1,875,000 for ten years.[17]
- 4,932 KWH (kilowatt hours) of energy per year.
- Emissions reductions of 0.39 lbs of CO2e per KWH.
- Each home installation would cost almost $18 thousand or about $6/watt.
- This would generate almost 10 job-years per million dollars spent.
- RDEIR Volume 2 Table 4.8-5 identified 27 MTCO2e of reductions resulting from these assumptions in the first year, and 270 MTCO2e total in ten years.[18]
- Applying these assumptions, the calculation would result in about 31 homes/year retrofitted, about 312 in 10 years.[19]

This would build a capacity of about 93.8 kW in one year, and about 938 KW in ten years[20] if this was actually carried out. That provides small emission reductions, which could be significantly beefed up in a superior alternative.

Using the RDEIR assumptions but instead concentrating the $30 million on a specific solar and electric vehicle program would result in far more substantial local energy transformation:

[16] DEIR Volume 2, Table A4.8-CGRP-6, at 2667th and 2668th unnumbered page of pdf.
[17] This is 1/16th of the total of $30 million dollars over ten years, since the DEIR describes an assumption that the money would be spread evenly over the 16 programs, and identifies these levels
[18] DEIR Volume 2, Table A4.8-CGRP-18, Summary of Programs Community GHG Reduction Program, at 2686th page of pdf.
[19] $187,500/year, divided by $6000 rebate /home = 31.25 homes/year
[20] 31.25 homes /year X 3KW/home = 93.8KW/year, times 10 years = 938KWs

A Specific Energy Transformation Scenario that instead concentrates Chevron's $30 million funding on Solar Electric & Electric Vehicles

Specific Project	Cost	GHG Reduction (MTCO2e)	Local Jobs
Offsite Residential Solar: Same $6000 rebate/ home for 3KW installation, use local labor	**$15 million for 2,500 homes, 7.5 MW over 10 years**	**2150[21]avoided emissions in 10 yrs**	**150 job-years according to RDEIR assumption of 10 jobs-years /million dollars for solar**
Electric Vehicle (EV) rebate –Double the RDEIR assumption for a rebate from $1000 per EV to $2000	**$7.5 million for 3,750 vehicles total over 10 years**	**16,500[22] in 10 years**	**More complicated – this was not evaluated in the RDEIR - see below**
Install EV Charging Stations*	**$7.5 million for 250 stations over 10 years**	**8,750[23]**	**More complicated – this was not evaluated in the RDEIR - see below**
Chevron onsite Solar: 8MW	**(Separate from CGRP fund)**	**2664[24]**	**RDEIR should add analysis of jobs generated**
Adding Energy Storage to the onsite Chevron 8 MW proposal addresses the RDEIR's comment about not providing energy 24 hrs per day	**(Separate from CGRP fund)**	**Evaluation of appropriate local system should be performed**	**The RDEIR should add calculations on jobs generated through energy storage**
TOTAL	**$30 million CGRP fund**	**28,462 + Energy Storage benefit**	

[21] At 0.86 MTCO2e saved per 3kw system (according to Chevron RDEIR Volume 2, Table A4.8-CGRP-6 – Residential Solar Rebate) times 2500 homes = 2150 MTCO2e
[22] At 4.4 MTCO2e saved per average vehicle (according to Chevron RDEIR Volume 2, Table A4.8-CGRP-9 –EV Purchase Rebates) times 3,750 vehicles = 16,500 MTCO2e
[23] At 35 MTCO2e saved per charging station (according to Chevron RDEIR Volume 2, Table A4.8-CGRP-10 –EV Station) times 3,750 vehicles = MTCO2e
[24] At 666 MTCO2e saved per year for a 2KW system (according to Chevron RDEIR Volume 2, Table A4.8-CGRP-16 –2 MW Solar Project) X 4 (to scale up for 8MW system) = MTCO2e

* Charging stations would preferably be solar. Examples are listed in the footnote.[25]

This specific program provides over 5 times the GHG emissions reductions (28,462 MTCO2e), not including the Energy Storage benefits, compared to the Chevron example for the 93% facility utilization scenario (5500 MTCO2e). However, this is still far lower than the total increase from the proposed Project, because the increase is extremely large (725,579 MTCO2e).

For the 8 MW onsite Chevron project, this was found to be feasible, but rejected presumably because it would not provide electricity all the time. While this is not a reason to reject the emissions reductions that would be achieved by this onsite solar project, the off-hours problem can be rectified by adding Energy Storage to the Project. Energy Storage provides many well-known benefits, briefly discussed later.

None of the above numbers included avoided emissions from drilling operations that produce natural gas, which can be enormous, and which can greatly increase the cradle to grave emissions associated with using gas-fired electricity. Taking these emissions into account would increase the emissions reduction estimate from this specific CGRP program.

Energy Storage is a clean energy game-changer, because currently, electricity is planned for the hottest peak hour in ten years. But with storage, renewable energy can be generated off-peak, and saved for peak use. This can drastically reduce fossil-fueled power plants and greatly increase the effectiveness of renewable energy including solar, wind, and others.

Duke Energy reported installation of a 153 MW wind plus energy storage facility in Texas, which it called the world's largest.[26] Such storage could also be paired with solar. The Duke system demonstrates the feasibility of large energy storage systems. This system provides far more energy than the 8MW proposed Chevron onsite solar facility, which would be modest by comparison.

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[25] Examples of literature on solar charging for EVs include: The Business Model for Solar-Powered Electric Car Charging (A. Tesla Supercharger, B. Netherlands Fastned, C. GM Onstar examples), http://www.plugincars.com/solar-powered-electric-car-charging-business-model-127710.html
Argonne National Laboratory's Pilot Solar Electric Vehicle Charging Project, http://www.transportation.anl.gov/smart_grid/ev_pilot.html , and The World's First Portable Self-Contained Solar EV Charging Station, http://www.plugincars.com/here-now-worlds-first-portable-self-contained-solar-ev-charging-station-128015.html

[26] World's Largest Wind Energy Storage System Launches in Texas, 01/24/13, Inhabitat.com, Energy section, http://inhabitat.com/worlds-largest-wind-energy-storage-system-launches-in-texas/ [*"North Carolina-based Duke Energy [2] just flipped the switch on what the company claims is the world's largest battery power storage system. Situated at their Notrees wind farm [3] in western Texas, the $44 million, 36-megawatt facility utilizes cutting-edge technologies to provide storage for—and therefore a steady supply of power from—the 153-megawatt renewable energy plant which supplies electricity to Walmart"*]

Market Watch[27] (from the Wall Street Journal) recently reported on small Energy Storage models, including a Southern California Edison solar / car charger / battery storage example:

> Southern California Edison recently installed stacks of lithium-ion batteries at an Irvine, Calif., parking garage that has solar panels on the roof and a row of electric-car chargers on a lower floor. The panels generate electricity for the car chargers and the batteries, which help power the chargers after sunset.

Many different Energy Storage types are now viable, including molten salt, ice storage, batteries, flywheels, and more.

Chevron's proposed 10-year funding should be extended to 20 years--more in line with the Project life, allowing for added funding for energy efficiency, public transit, and bicycle projects

Project lifetime like the Chevron proposal is typically decades (at least two, likely much longer). The CGRP program to provide local GHG offsets for the Project should likewise be extended for at least two decades. This is especially true since the cap-and-trade program, (where most of the GHG emissions reductions are proposed for offsetting the Project) is currently planned only through 2020 (5 years). So the CGRP funding should continue for 20 years instead of 10, (doubling the total to $60 million). Furthermore, Richmond would substantially benefit by front-loading the funding, to facilitate a faster transformation toward clean energy. Such funding would support an Expanded Energy Transformation Scenario.

This scenario would build on the Specific Energy Scenario (Solar + EV + Storage measures) on the previous page. Excellent candidates to add would be local energy efficiency plus public transit and bicycle programs, which could make much more progress with this concentrated level of funding. Such programs were listed in Chevron's potential list of CGRPs, but the example scenario provided spread the funding too thin to make much progress. With increased funding, these become more viable.

Promoting local jobs generation and other local economic advantages by concentrating Green Energy in Richmond

Increasing the concentration of local green energy in Richmond builds the local economy toward one most likely to succeed in the future, thus providing security and increasing sustainability for Richmond residents away from the fossil fueled economy, which must be phased out. If substantial funding was firmly committed by Chevron to offset a portion of its major greenhouse

[27] Feb. 27, 2014, For Storing Electricity, Utilities Push New Technologies, http://www.marketwatch.com/story/for-storing-electricity-utilities-push-new-technologies-2014-02-27-194493214

gas emission for local green energy projects, this can increase the long term economic security of Richmond.

For example, unlike other sectors, solar jobs are expanding. According to the RDEIR, ten solar jobs would be created per million dollars spent. A report (*Sharing Solar's Promise: Harnessing LA's FIT to Create Jobs and Build Social Equity*) by the Los Angeles Business Council, USC, and UCLA found that solar job growth within California (8.1 percent in 2013) outpaced overall job growth (1.7 percent),[28] but also found much more work can be done to further such jobs growth. While this report focuses on Los Angeles, it contains much information relevant to Richmond, highlighting solar as a key sector to support (also described in the equity section below.

The report also found that a spatial mismatch exists between jobs and job seekers. Many workers in the solar industry have a hard time finding employment. Workers face a choice between traveling far distances for work or decreased job prospects. While traveling long distances for construction jobs is somewhat of an industry norm, even for low-income workers, the additional expenses for transportation and childcare, can make the cost of work particularly high. This is true in many geographic locations. Bolstering available solar jobs in Richmond will help to provide jobs for individuals who are *already* trained (and adding training programs would help the local workforce to gain access to new solar jobs generated).

Adding substantial rooftop solar also provides benefits of Distributed Generation, including the following potential benefits identified by a FERC study (the Federal Electrical Reliability Council) on Distributed Generation:[29]

- Increased electric system reliability
- Reduction of peak power requirements
- Provision of ancillary services, including reactive power
- Improvements in power quality
- Reductions in land-use effects and rights-of-way acquisition costs
- Reduction in vulnerability to terrorism and improvements in infrastructure resilience

For electric vehicle-related jobs, it is difficult to separate jobs generated due to purchases of electric vehicles from jobs from installation of charging stations, and from maintenance activites, but studies are available on economic advantages of EV incentives. The RDEIR did not provide specific jobs estimates for EVs. A 2013 report on jobs and economic impacts due to the EV

[28] By the LABC Institute (Los Angeles Business Council), UCLA School of Public Affairs (the Luskin Center for Innovation), and USC's Program for Environmental and Regional Equity (PERE) (2014, at p. 3, http://labcinstitute.org/files/LABC_Sustainability_Report_Only_2014_FINAL.pdf

[29] https://www.ferc.gov/legal/fed-sta/exp-study.pdf

industry by the International Economic Development Council[30] found that most money spent on gasoline leaves local communities, in contrast to measures that reduce gasoline use (such as transportation electrification) which increase dollars kept in the local community:

> According to the U.S. Energy Information Administration, over 80 percent of the cost of a gallon of gas immediately leaves the local economy. . . .
>
> A study by the California Electric Transportation Coalition found that each dollar saved from gas spending and spent on other household goods and services generates 16 jobs in the state. [citation omitted] A few specific examples underscore how significant the import substitution effect of electric vehicles can be. New Yorkers drive much less than the average U.S. metro resident, which keeps $19 billion each year flowing within the local economy. [citation omitted] In Portland, Oregon, residents drive only four miles less per day than the national urban average, but the fuel savings still result in $2.6 billion dollars each year staying local. . . .
>
> Electric vehicles prevent local wealth from being literally pumped away and, as these examples make clear, the gains to local economies can be significant.

The report also found that communities that had early-adoption of programs for EV incentives act as magnets for more people interested in transportation electrification:[31]

> Before charging infrastructure becomes widespread, communities that can offer adequate charging locations and PEV purchase incentives will have an advantage in attracting and retaining workers who want to make the switch to electrified transportation.

EVs can reduce utility rates especially when coordinated to charge at night when power is cheap:

> The reason that electric vehicles may actually decrease utility rates lies in daily oscillations in power consumption. Electric vehicles typically charge at night, when electricity is cheapest to generate. By balancing the demand for electricity between day and night, electric vehicles decrease the average cost of electricity.

EVs can also provide energy storage capacity to the grid called "vehicle to grid" (V2G) can increase use of clean energy, and earn vehicle owners $300 to $500 per year by providing electricity back to the grid. Such programs could also earn owners far more (many thousands of dollars per year) by providing "spinning reserves" and "frequency regulation" needed by the grid, normally supplied by fossil-fueled power plants:

> Peak hours of electricity demand generally occur in the early to mid-afternoon, when most commuter vehicles are sitting idle and can feed power back into the grid. [citation omitted] Conversely, electric vehicles are generally charging in the later-evening, overnight, and in the early morning, when there is excess generation capacity in the grid.

[30] Creating the Clean Energy Economy, Analysis of the Electric Vehicle Industry, 2013, International Economic Development Council, at pp. 6-7 http://www.iedconline.org/clientuploads/Downloads/edrp/IEDC_Electric_Vehicle_Industry.pdf

[31]

> **As a result, large-scale deployment of electric vehicles will allow utilities to dispense with power plants that are currently only needed to satisfy peak demand, a prospect that could substantially decrease operating costs and therefore utility rates.** Further, V2G can accommodate greater use of clean energy. Electric vehicles primarily charge from late afternoon to early morning, a period during which a greater portion of energy is generated from clean energy resources such as wind.
>
> Initial studies estimate that electric vehicle owners can make $300 to $500 per year through V2G. However, this may differ from grid to grid. Electric vehicles may earn more by providing a backup power source for quick-response utility markets. These markets include "spinning reserves" generation, which provide immediate backup power for 10 minute spurts, and frequency regulation, which balances generation to ensure an even electricity flow through outlets at all times. . . .
>
> Frequency regulation requires adjusting output about 400 times a day, and electric vehicles can respond within seconds to this need. It is possible that electric vehicles can earn up to $5,000 a year in frequency regulation markets. [citation omitted] Nuuve Corporation, a leading V2G pilot program, is currently testing 30 electric vehicles for the frequency regulation market in Denmark and expects to pay electric vehicle owners up to $10,000 over the lifetime of the car.

There can also be a synergy between solar and EV installations; once upfront costs are covered, since the combination is like having free gasoline. While jobs from electric vehicle *manufacture* would not necessarily be local, charging installation and maintenance jobs can be, as well as the other local economic advantages from promoting EVs identified above.

Training programs are key to ensure that local Richmond residents can provide the services needed to begin the transformation to clean energy. Such programs can help low income residents, and help oil industry workers who are exiting the oil industry and looking to transition to green jobs. Examples described in the *Sharing Solar's Promise* report (cited above):

> **Training the Next Workforce: LA IBEW 11 / NECA and ELASC**
>
> Programs by the Los Angeles International Brotherhood of Electrical Workers Local 11 and National Electrical Contractors Association (LA IBEW 11/NECA) and the East Los Angeles Skills Center (ELASC) provide models for solar-focused workforce development. Graduates of LA IBEW 11/NECA's five-year Apprenticeship Program and Journeyman Training are highly-skilled electricians and often work on complex commercial and industrial solar projects. ELASC offers a series of photovoltaic installer courses to the clients of Homeboy Industries, which serves former gang members, as well as to East Los Angeles residents. In addition to preparing students for the NABCEP entry-level certification exam, ELASC equips students with English and math skills that are essential for the job; similarly, LA IBEW 11/NECA provides access to an online technical math course for applicants who might have difficulty meeting IBEW's algebra requirement. (p. 7)

> **Training programs are connecting with workers from disadvantaged areas, but the need is high.** Training programs are scattered across Los Angeles, and many are located in low-income, struggling areas in the San Fernando Valley, Downtown and East Los Angeles. [citation omitted] Several programs specifically target disadvantaged workers and at-risk youth, including Homeboy Industries' Solar Installation Training and Certification Program, which works with ex-offenders and former gang members, and the Los Angeles Conversation Corps' (LACC) Green Job Training Program, which serves low-income and at-risk youth. They focus on recruitment, soft skills development, social service provision and job placement and partner with adult skills centers and technical colleges for hard skills training. (p. 8)

Equity is needed in Green Energy Incentives

While moving toward Green Energy in Richmond provides the best likelihood of an economically secure and healthy future, clean energy is frequently only available to upper income folks, because even though clean energy is cost-effective over a period of years, upfront costs are higher than low income people can afford. But setting up rebate programs to address equity issues can address this problem.

The Charge Ahead campaign (which seeks to increase electric vehicles in California by 1 million by 2020), identified these economic benefits of electric vehicles for communities, especially for low income families:[32]

> The average household spends $2,756 on gasoline and motor oil annually, straining family budgets and hitting lower income households especially hard.[5] Between 2005 and 2010, the average per capita expenditure on transportation fuels doubled relative to the previous six years, as the price of a barrel of oil jumped. [Citation omitted.] Unlike gasoline prices, which fluctuate with the global oil market, the price of electricity is stable because it comes from a diverse, largely domestic supply and is carefully regulated by the state's Public Utilities Commission. Driving on electricity in California is equivalent to paying only one dollar-per-gallon in a gasoline vehicle. [Citation omitted.] If the average American household were to drive on electricity, it would save over $2,000 annually, reducing its fuel bill by more than two thirds

The Charge Ahead campaign also identified the following methods for increasing equity in access:

- Vouchers for Transit and Electric Car Sharing
- Charging stations in Multi-Unit Dwellings & City Municipal buildings
- Partnerships with Community based organizations for Implementation, including appropriate locations
- Combining incentives for clunker scrapping with modified incentives for purchasing/leasing New or Used EV's (This piece needs to be administered by a state agency)

[32] Charge Ahead – One Million Cars, Trucks, and Buses, Fact Sheet.

- Enhancing Financing Options for EVs for people with limited credit (This piece also needs to be administered or in concert with a state agency)

There are existing programs to increase equity in access to solar and energy efficiency, and additional money could be added by the Chevron funding to increase low-income access:

- **Virtual Net Energy Metering for Multifamily Affordable Housing** (NEMVMASH) (MASH/NSHP) with Solar Generators[33] -- Tenants are eligible for PG&E's Virtual Net Energy Metering (NEMVMASH) tariff. This program allows all tenants in an affordable housing complex to benefit from energy generation credits derived from the building's solar system. If the building meter configuration qualifies, tenants in buildings participating in the MASH program will automatically be enrolled in this tariff, which does not change their existing rate schedule.
- **Add funding to Marin Energy Efficiency** programs for low income families[34]
- **Funding could be made available to pay for low income families who want to participate in Marin Clean Energy,** for exit fees from PG&E

These are examples – a fuller analysis should be carried out on equity in access to clean energy, and measures promoting access for all should be adopted when dispersing funds for a CGRP. It would be unfair for community members who are heavily burdened by local air pollution to be excluded from a funding program for clean energy. Higher levels of rebates should be available to low income communities.

According to the *Sharing Solar's Promise* (cited above) an increasing body of research including from organizations such as the Federal Reserve and the International Monetary Fund, show that economic growth strategies that advance social equity can also result in long-term, general economic growth. (p. 7)

Adopting local CGRPs is environmentally superior because it reduces problems related to almost exclusive use of cap-and-trade allowances to meet GHG reductions

CEQA requirements go beyond the requirements of other laws, and require that all feasible mitigation measures and an environmentally superior alternative be evaluated and adopted. Therefore, the Chevron RDEIR should evaluate potential impacts associated with the use of cap-and-trade allowances to offset over 99% of Chevron's proposed increases. The RDEIR should adopt locally verifiable emissions reductions instead.

The potential impacts and potential for ineffectiveness in achieving reductions from carbon trading programs have been repeatedly documented, and need to be evaluated in the RDEIR:

[33] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_NEMVMASH.pdf
[34] http://www.marincleanenergy.org/PDF/03B_Blackline_of_MEA_PIP_Corrected.pdf

- **California Assembly member Nancy Skinner found cap-and-trade's new offsets program will actually incentivize coal mining.** She serves on the State's committee on natural resources and public safety, and wrote to the California Air Resources Board (CARB) requesting it postpone indefinitely the adoption of the mining methane offsets protocol. According to Skinner, "The protocol, as written, will subsidize coal mining, likely for export … Mine Methane Capture [offsets] could actually increase carbon emissions … We cannot have a policy that directly incentivizes coal mining. The best way to reach our AB 32 goals is to keep coal in the ground."[35] It would be especially ironic if, after the only part of California that uses substantial imported coal-fired electricity has made a commitment to divest from coal, that Richmond would then rely on carbon offsets that could pay money to coal mining operations, effectively subsidizing them.
- **Columbia University found a failure to achieve reductions in all carbon trading programs in early years, or in all years:** A Columbia University study evaluated several U.S. trading programs (EPA's Acid Rain trading, Los Angeles's RECLAIM, the Chicago ERMs program), and the European carbon trading program, and found that every program suffered from overallocation of allowances either in the early years or in all years. This resulted in the failure to meet emission reduction goals for many years, because with too many credits available, allowance prices were too cheap to push investment in low carbon technologies.[36]
- **The International Energy Agency found that free allocations of credits and banking (allowed in California's cap-and-trade Program) can delay reductions, and lock in a high carbon infrastructure, resulting in no long term emission reduction progress:**[37] This agency found that standard features such as free allocations (a major feature of California's cap-and-trade program) caused delays in achieving reductions. The investigation found that free allocation slows progress toward low-carbon technologies, and that overallocation and banking of credits (both allowed in California's cap-and-trade) caused delays. It found that extensive offsets (generously allowed in California's cap-and-trade at 8%) could result in locking in a high carbon infrastructure in the short term so that no progress would be made in the long term. In addition to the delays in achieving environmental improvements, this study also found that the standard approaches of cap-and-trade providing free allocation were not shown to be in the public's economic interest. It found these lead to windfall profits, do not prevent price increases to consumers, and that there are alternatives for offsetting consumer prices.
- **Widespread fraud in international carbon trading programs has been reported** by the Times World Business Editor,[38] the Guardian business news,[39] the BBC,[40] which

[35] http://ecowatch.com/2014/04/27/countries-criticize-californias-carbon-offsets/
[36] Colum. J. Envtl. L. 395 (July 17, 2009), Overallocation Problem in Cap-and-Trade: Moving toward Stringency, The; McAllister, Lesley K., http://www.columbiaenvironmentallaw.org/assets/pdfs/34.2/7._McAllister_34.2.pdf
[37] Reviewing Existing and Proposed Emissions Trading Systems, Nov. 2010, International Energy Agency, http://www.iea.org/papers/2010/ets_paper2010.pdf (Ellerman, 2010; European Commission, 2010)
[38] Carl Mortished: World Business Editor, The Times, (Attached as CBE Exhibit F Times carbon trading fraud) http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article7066315.ece
[39] Terry Macalister, guardian.co.uk, 20 February 2011, http://www.guardian.co.uk/business/2011/feb/20/carbon-emissions-trading-market-eu
[40] BBC News, published 2010/02/03, http://news.bbc.co.uk/go/pr/fr/-/2/hi/technology/8497129.stm

found that at least large volumes of invalid credits were manufactured, and large volumes stolen. Such fraud was so rife that it crashed the entire program, forcing closure of the program due to panicked investors.

- **Economist Hazel Henderson found cap-and-trade allowances are almost impossible to verify.** (She was previously advisor to the U.S. Office of Technology Assessment and the National Science Foundation, and with the Calvert Group of investors.) She also found that pollution trading programs were ineffective and vulnerable to fraud.[41]
- **A USC / UC Berkeley study, Minding the Climate Gap[42] found that some trades or allowance allocations could widen the climate gap by deepening disparities in emissions burdens by race/ethnicity**. The report found that refineries made up the greatest part of the emissions burden and risk of increased impacts. It also found that targeting these facilities for direct cleanup would benefit everyone, and that the opportunity to do this would be lost if cap-and-trade credits were used instead. (p. 21) The report states: "The research reviewed here suggests that the concerns of environmental justice advocates about the unequal impacts of cap-and-trade are not misplaced. The major facilities that will be regulated under any carbon reduction program are more frequently located near people of color and lower-income communities, with a handful of petroleum refineries making a significant contribution to the pattern of inequity." (p.25) **International carbon trading forest offsets programs have been found to result in destruction of old growth forest in favor of monoculture plantations.** The REDD program (Reducing Emission from Deforestation and Forest Degradation)[43] has been criticized because "The United Nations definition of "forest" does not distinguish between a tropical old-growth forest and an industrial monoculture tree plantation. . . . This means that if someone is able to demonstrate that a plantation can store more carbon than an existing forest, the conversion of this forest into a plantation will receive the blessing of the U.N. and the forest's destruction will be subsidized through REDD." Although planting commercial forests may balance carbon emissions, native forests offer natural diversity, delicate ecosystems, home to a variety of species which can't be restored by planting commercial forests. Indigenous people are also harmed by such forest destruction. Impacts of California's forest offsets programs should also be evaluated.

Local CGRPs in Richmond avoid potential environmental impacts caused by inappropriate forest offsets programs, incentivizing coal mining, other carbon trading programs, and avoid the impacts associated with ineffective carbon credits described above (which means that greenhouse gases will not truly be offset).

[41] *As Kyoto Expiration Nears, Emissions Trading Shown Ineffective,* by Hazel Henderson, Monday, May 23, 2011, Inter Press Service, Hazel Henderson, author, president of Ethical Markets Media (USA and Brazil), co-developed with the Calvert Group the Calvert-Henderson Quality of Life Indicators and co-authored "Qualitative Growth" (2009), Institute for Chartered Accountants of England and Wales, http://www.globalissues.org/news/2011/05/23/9757

[42] *Minding the Climate Gap, What's at Stake if California's Climate Law isn't Done Right and Right Away*, Pastor, Morello-Frosch, Sadd, Scoggins, April 16, 2010, http://dornsife.usc.edu/pere/documents/mindingthegap.pdf

[43] http://www.theinternational.org/articles/487-un-redd-program-criticized-for-negative

Adopting local CGRPs is environmentally superior because directly reduces local emissions

In addition to the reduction in greenhouse gases identified earlier, a firm commitment to specific CGRPs including solar, electric vehicles, and energy storage (as well as reductions that would be achieved through a 20-year funding including energy efficiency, public transit funding, and bicycle programs), CGRPs would reduce co-pollutants. A specific set of local reductions achieved should be provided in the CEQA process.

For example, the aforementioned Charge Ahead campaign literature found the following regarding benefits of electric vehicles[44] -- four in ten Californians live close enough to a freeway or busy road to put them at increased risk of asthma, cancer and other health hazards, providing another reason for promoting Electric Vehicles. Exhaust from cars, trucks and buses pollute the air and contribute to climate change. Dirty air from vehicles makes tens of thousands of Californians sick, and costs billions in avoidable health costs. Dependence on oil means Californians have no place to turn when gas prices rise. Transitioning to cleaner and more efficient cars, trucks and buses, and reducing oil refining over time will benefit every Californian, and in particular Richmond by improving local air quality.

Additionally, roughly a third of the nation's 140,000 electric cars have been purchased in California, largely to the Clean Vehicle Rebate Project. While California leads the market nationally, plug-in electric vehicles still only account for less than two percent of new vehicle sales in the state. That number needs to increase to at least 15 percent by 2025 to put us on track to meet the state's longer-term air quality and climate goals. It also found that making such progress would accelerate a mainstream, self-sustaining market for electric vehicles and reduce air pollution by extending the Clean Vehicle Rebate Project.

This would result in significant co-pollutant reductions as well as greenhouse gas reductions. Such potential co-pollutant benefits for a specific and firmly committed CGRP program should be evaluated in the EIR process.

[44] Charge Ahead – One Million Cars, Trucks, and Buses, Fact Sheet.

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Experience

1989-present **Energy and Industrial Air Pollution Engineering Evaluation**

- Oil Refinery, industrial air pollution source evaluation including criteria pollutants, toxics, greenhouse gases, pollution prevention methods and engineering solutions.
- Research best and worst industrial practices, chemical and fossil fuel phaseout methods, policy, and technologies.
- Evaluation of energy issues including electricity planning, natural gas and coal-fired power plant permitting and impacts, transmission and reliability issues, alternative energy and policy options.
- Analyzing permit language, conditions, emissions and air monitoring data; compiling health and environmental impacts data. Evaluation regulatory compliance with environmental laws. Negotiating practical issues of regulation with industry and government agencies to craft health-protective policy and regulatory language.
- Translating inaccessible technical information into lay language and educational materials. Providing technical assistance and cumulative impacts analyses to communities facing severe pollution burdens. Assisting communities and workers in achieving environmental health protections in permitting and policy.
- Managed science department for statewide environmental organization (CBE). Hired by regulatory agency as technical advisor to identify feasible air pollution control methods not previously adopted, and to assist communities submitting comments during regulatory proceedings.

Education

1981 **B.S. Electrical Engineering**, University of Michigan, Ann Arbor

Project examples:

- Evaluation of various proposed refinery, permitting, regulations, oil extraction and pipeline permitting in California since 1989, including Northern and Southern California refineries. Also emissions and solutions relating to feedstock switches to Canadian tar sands crude oil nationally. Oil drilling operations, air impacts, in residential Los Angeles neighborhood. Pipeline transport impacts of crude oil, hydrogen, and other oil industry feedstocks in California and Midwest. Evaluation of coal gasification plant emissions
- Evaluation of California Long Term Procurement Planning in 2010-2014 (electricity planning) and California power plant permitting, reliability requirements and low carbon solutions, transmission issues, environmental impacts, local and system capacity needs, quantification of available renewable and energy storage resources
- Development of model California oil industry criteria pollutant regulation, and proposed greenhouse gas regulation and alternatives analysis, including flares, pressure relief devices, storage tanks, fugitive components, marine loading, and others. (1990s to present)

Positions

2004- present	**Senior Scientist, Communities for Better Environment and Independent Environmental Consultant –** Energy Use / Industrial pollution quantification / Alternatives analysis, engineering analysis of proposed and existing industrial permits, analysis of statewide goals and energy planning, as well as policy analysis. Analysis of impacts and solutions to environmental problems including trends in fossil fuel use, renewable energy, oil industry feedstocks, associated equipment changes, emissions of criteria pollutants, toxic emissions, and greenhouse gases. Technical consultant in community campaigns on industrial regulation. Geographic areas including Southern California and Northern California, and multiple U.S. states and tribal areas.
2001-2003	**Statewide CBE Lead Scientist, CBE,** Oakland, CA Responsible for team providing technical evaluations within community and environmental law enforcement campaigns. Also evaluation of electric power plant expansion air emissions in community of color with high asthma rates: identification of alternatives to fossil fueled plants, including conservation, renewables generation, improved transmission, in California Energy Commission proceeding. Analysis of and recommendations for regulation in Bay Area Ozone Attainment Plan (flares, pressure relief devices, wastewater ponds, storage tanks, others) which were ultimately adopted. Evaluation of Environmental Impact Reports and Title V permits for refineries and chemical plants, including emissions, community impacts, alternatives. Successfully assisted negotiating Good Neighbor Agreements by identifying technical solutions to environmental violations to bring facilities into compliance.
1990-2001	**Clean Air Program Director, Northern California Region, CBE** Analysis of permits, regulation, air pollution inventories and other emissions information for oil refinery, power plant, cement kiln, smelter, dry cleaner, consumer product, lawn mower, mobile source, and other air pollution sources, neighbor and worker health impacts, with pollution prevention policy development. Successfully advocated for national models of oil refinery regulation. Evaluation and documentation of root causes of industrial chemical accidents as part of community campaigns for industrial safety. Technical assistance to community members negotiating Good Neighbor Agreements with refineries. Evaluations towards adoption of policies eliminating ozone depletors in favor of alternatives.
1987-1990	**Research Associate, CBE** Campaign with maritime workers and refinery neighbors for adoption of strict oil refinery marine loading vapor recovery regulation, which became statewide and national model. Member of technical working group at BAAQMD evaluating emissions, controls, safety, and costs. Also school pesticide analysis, successful policy campaign for integrated pest management on school grounds.
1986	**Assistant Editor of appropriate technology publication, Rain Magazine**, Portland, OR Production of publication on innovative energy and environmental success models around the U.S. and the world. Compiled, co-edited, wrote, and provided production for non-profit publication.
1981-1985	**Electrical Engineer, National Semiconductor Corp., Santa Clara, CA** Electronics engineering design team member for analog-to-digital automotive engine controls for reducing air emissions. Troubleshooting hardware and evaluating fault-analysis software efficacy.

Response to Comment Letter No. G1-81

Communities for a Better Environment

Comment G1-81.1

I. Introduction and Summary –Tesoro LARIC DEIR and Title V permit deficiencies need correction

This report provides my expert opinion of the Tesoro Los Angeles Refinery Integration and Compliance Project (the "Project") Draft Environmental Impact Report (DEIR) and Draft Title V Permit, distributed by the South Coast Air Quality Management District (AQMD) in March 2016 for public comment.[1] I am a Senior Scientist at Communities for a Better Environment (CBE). For over 25 years I have provided engineering evaluation of oil refinery and oil industry permitting and regulatory development, impacts, and pollution prevention options and alternatives, on projects in California, Michigan, Illinois, Indiana, Oregon, N. Dakota, Texas, and Washington, as a consultant to various organizations and agencies, and as a CBE staff member. I have also evaluated impacts and causes of dozens of oil refinery accidents and releases and personally witnessed many.

[1] South Coast Air Quality Management District (AQMD), available at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---year-2016

G1-81.1

Response G1-81.1

The comment is introductory to the comment letter and summarizes the background of the commenter. No response is required under CEQA.

Comment G1-81.2

This Project is one of the most extensive seen in the South Coast, merging Tesoro's Wilmington and Carson California refineries into the largest refinery on the West Coast (380,000 barrel per day),[2] including the following (see sections later for details and citations):

- Expansion of the Carson FCCU (Fluid Catalytic Cracking Unit) and Hydrocracking Unit to accommodate feed from shutting down the Wilmington FCCU as part of integration, and increased utilization of regenerators, cogeneration units, and incinerators;
- New Propane Storage and Treatment Unit, expanded rail for LPG delivery (Liquefied Petroleum Gas), Sulfuric Acid Regeneration Plant, Wet Jet Treater, and many hydrotreaters (for removing hazardous sulfur contamination);
- At least a dozen new pressure relief device connections to refinery flares;
- New or increased use of at least 22 heaters and boilers (which are major drivers of oil refinery processes, air pollution sources, and energy use), and shutdown of 6 Wilmington FCCU heaters;

  Construction of an unprecedented volume of 8 new crude oil storage tanks totaling 3.4 million barrels (bbls) of volume, with about 420,000 bbls/day in increased throughput, plus expanded use of many existing tanks. The new tank throughput alone is greater than the current daily crude oil use at the entire Tesoro LA refinery complex.[3]

Photo of part of a 500,000-bbl tank
http://www.bloomberg.com/news/articles/2012-09-27/the-oil-hub-where-traders-are-making-millions

[2] 380,000 bpd is Tesoro's figure of maximum capacity: http://tsocorp.com/refining/los-angelescalif/; the DEIR differs in calling it a 363,000 bpd refinery, for example at p. 2-17.
[3] (153 million bbls/year)/365 days/year=~419,000 bbls/day on average, compared to the Tesoro Wilmington and Carson Refineries (LA refinery complex), which Tesoro states has a full capacity of 380,000 bbls/day crude oil.

G1-81.2

Response G1-81.2

The comment describes the proposed project as extensive and then lists various elements of the proposed project. The complete description of the proposed project is provided in Section 2.7 of the DEIR. SCAQMD agrees that the items listed are elements of the proposed project with the clarifications listed below:

The comment includes a footnote which highlights a difference in the Refinery capacity of 363,000 bbl/day listed in the DEIR versus the 380,000 bbl/day, which is listed on Tesoro's website. Master Response 5 explains the difference in the 363,000 bbl/day Refinery crude oil capacity stated in the DEIR and the 380,000 bbl/day capacity recently reported in SEC filings and on Tesoro's website.

The comment suggests that the proposed project "merges" the Tesoro's Carson and Wilmington Operations into the largest refinery on the West Coast. As explained in detail in Master Response 7, Tesoro's acquisition of the BP's West Coast Value Chain, including the Carson Operations, was approved by the Federal Trade Commission and the California Attorney General and occurred in June of 2013. The Carson and Wilmington Operations have already merged; the two pre-existing refinery operations have been operating as one Refinery since the acquisition. As described in Section 2.1 of the DEIR, the proposed project is designed to better integrate the Carson and Wilmington Operations, and will result in less emissions locally.

The comment incorrectly refers to "expansion" of the Carson Operations FCCU. No physical modifications are proposed at the Carson Operations FCCU; as noted in the DEIR, the throughput capability of the Carson Operations FCCU will remain unchanged (see Section 2.7.2.2). However, as noted in Section 4.1.2.3 of the DEIR, the Carson Operations FCCU is expected to operate more consistently at its demonstrated capacity of 102,500 bbl/day.

The comment refers to new or increased use of 22 Refinery heaters and boilers. The DEIR provides a thorough evaluation of potential project impacts; including direct and indirect impacts (see Section 4.1.2.1 of the FEIR). Seven heaters would be installed or modified as part of the proposed project resulting in direct project impacts. In addition to these direct impacts associated with the proposed project, "…the proposed project may have indirect impacts on downstream equipment by causing increased utilization from operational changes, even though the equipment is not part of the proposed project, that is, it is not modified in any way, is operating within existing permit limits and no permit modification would be required." The majority of the 22 heaters referenced in the comment are currently permitted to operate at the levels analyzed in the DEIR.

The comment refers to eight "new" crude oil storage tanks. It should be noted that two of the proposed 300,000 barrel tanks would replace two existing 80,000 barrel storage tanks. Additional comments are made regarding the proposed throughput for the new and replacement storage tanks which are addressed in detail in Response G1-81.39. Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's

Carson and Wilmington Operations. Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the proposed permit revision of the DCU H-100 heater. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR.

Comment G1-81.3

According to the DEIR, the Project would:

- **Have mostly neutral impacts on air emissions** but increase VOCs and decrease CO (it would be neutral for GHGs, NOx, SOx, and Particulate Matter,[4] due to both use and generation of air pollution credits to be later used by Tesoro or others companies to offset expansions), and
- **Significantly increased risk of explosion and toxic release** (from LPG rail unloading, the Hydrocracker, Catalytic Reforming Unit (CRU), Propane Sales Treating Unit (PSTU), and Sulfuric Acid Recovery Plant (SARP)[5]).

[4] DEIR, for example at p. 4-17 to 4-18
[5] DEIR, for example, pp. 4-45 to 4-47

G1-81.3

Response G1-81.3

The comment describes the proposed project air quality impacts and risks associated with several elements of the proposed project.

Contrary to the comment, there is no increase in the hazards associated with LPG rail unloading, the Hydrocracker, the CRU, and the PSTU (see Section 4.3.2.1, pages 4-45 through 4-54 of the FEIR). The worst-case consequence analyses in the DEIR show that the potential impacts from a release at the LPG rail unloading facilities and the Hydrocrackers do not change as a result of the proposed project. The worst-case consequences impact from the PSTU are contained within the existing CRU-3 potential impact zone, and therefore, do not change as a result of the proposed project. The DEIR found that hazards associated with the SARP are potentially significant based on worst-case release scenarios (see Section 4.3.2.1 of the FEIR).

Comment G1-81.4

This report finds DEIR deficiencies requiring correction including added impacts:

- **2016 Tesoro investor statements and other expert reports contradict the DEIR, and identify a broader project purpose** to increase the Tesoro LA refinery competitive advantage, connect West Coast assets, bring cheap crude to LA through the Tesoro Savage Vancouver Washington rail to ship terminal, in addition to increase flexibility between gas and distillate production and integrate the Wilmington and Tesoro refineries

- **Tesoro's baseline crude oil slate was undisclosed and can change substantially due to this Project,** especially through the import of N. Dakota Bakken crude oil emphasized in Tesoro's plans. Tesoro also has options to transport substantial Canadian crude oil, and to blend Bakken and Canadian crude to replace Alaska North Slope and California crude oil

- **The Project would include transporting new crudes from the N. Dakota Bakken and potentially Canadian tar sands by rail to Vancouver Washington, then by ship to the massive new storage tanks,** and could involve third party business and exports, as well as use within the two refineries making up the LA refinery complex.
- **Plans for introduction of large imports of Bakken crude oil to the refinery, cause new risks** starting with extraction by fracking, rail transport, ship transport, storage, blending, and refining, including GHGs, toxic and criteria pollutant emissions and harms to underground water supplies during extraction, explosions during transport, waxy deposits in railcars, ships, storage tanks, pipes, and refinery vessels requiring chemical dispersants and hazardous waste requiring disposal, coking during processing and when blended with heavier crudes, and introducing additional volatile toxic air contaminants including benzene.

http://www.kgw.com/news/photos-train-derailment-in-the-gorge/230445267

G1-81.4

G1-81.4 cont'd.

Response G1-81.4

The comment summarizes DEIR "deficiencies" and suggests additional analysis of the proposed project is required.

Response G1-81.22 through G1-81.24 clarify that Tesoro's corporate statements to investors and other reports do not identify a broader purpose of the proposed project of providing "advantaged crude oil," i.e., any economically advantaged crude oil capable of being processed at Tesoro's refineries, to its U.S. refineries (as that term is used by Tesoro) as claimed in the comment.

There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery.

Responses G1-81.28, G1-81.29, G1-81.34, and G1-81.36 address claims that baseline crude oil data was undisclosed. Additionally, Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94 clarify that the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

Responses G1-81.37 and G1-78.150 explain in detail why a blend of Bakken and heavy Canadian crude oil does not mimic ANS crude oil and is not suitable for processing in the Refinery without adding additional crude oils into the blend.

The proposed project does not include transporting new crude oils by rail to Vancouver, Washington and then by ship to the Refinery as claimed in the comment. Master Response 8, Response G1-81.30, and Response G1-78.139 explain in detail that the Vancouver Energy Project is unrelated to the proposed project.

Response G1-81.52 addresses the assumption that new and replacement crude oil storage tanks will be used for third-party business.

The other issues raised in the comment regarding importing Bakken crude oil causes new risks and are responded to in detail in subsequent responses as noted in Table 81.4-1.

The issues raised in the comment regarding increased Refinery impacts (GHG, TAC, and criteria pollutant emissions) from processing are not applicable because all crude oil purchased is blended and the proposed project does not change the crude oil operating envelope (acceptable ranges of several properties) or the crude oil blend.

No crude oil extraction impacts are associated with the proposed project. Responses G1-81.65 and G1-81.67 specifically address GHG impacts associated with crude oil production; however, the responses apply to other potential impacts, such as potential groundwater contamination. Crude oil production impacts will occur with or without implementation of the proposed project.

Table 81.4-1

Topics Raised in Comment and Location of Responses

Topic	Response	
	Master Response Number	Specific Cite or Response Number
Crude Oil Extraction Impacts are Not a Result of the Proposed Project	-	G1-81.55, G1-81.65 and G1-81.67
No Refinery Import of Crude Oil via Rail	-	DEIR Sections 2.6.1 and 2.6.2
Marine Transport Impacts are Included in the DEIR	6	DEIR pp. 4-26 and 4-27, G1-81.117
Storage Impacts were Based on Worst-Case Crude Oil Properties	6	G1-81.39, G1-78.114 and G1-78.157
Blending and Refining Impacts will not Change	4	DEIR Sections 2.5.3 and 2.5.4, G1-81.34, and G1-78.94
Bakken Crude Oil not Classified as Explosive	-	G1-81.57 and G1-78.160
No Impacts from Waxy Deposit in Bakken Crude Oil	-	G1-81.54, G1-81.55, and G1-78.162
No Coke Deposits from Bakken Blending or Processing	-	G1-81.56 and G1-78.170
Additional TACs were Analyzed in the DEIR	-	G1-81.39, G1-78.114 and G1-78.157

Note: - = No Master Response prepared on this topic.

Comment G1-81.5

- **Potential substantial additions of Canadian crude oil to the refinery, introduces additional new risks,** starting with extraction, transport, storage, blending, and then refining, including strip mining land and generation of toxic lakes, addition of volatile diluents during transport, crude by rail transport risk, extremely heavy and high sulfur content producing heavy sludge in storage vessels and requiring additional energy to desulfurize, crack, and coke, causing additional GHG, criteria, and toxic emissions.

G1-81.5

Response G1-81.5

Response G1-81.4 addresses most of the issues summarized in the comment.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the

Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Therefore, the issues raised in the comment regarding increased Refinery impacts (energy needs and GHG, TAC, and criteria pollutant emissions) from processing are not applicable because any crude oil purchased is blended and the proposed project does not change the crude oil operating envelope or the crude oil blend.

The only part of the comment potentially related to the proposed project involves management of sludge generated in storage tank vessels. The comment claims, without providing facts or supporting evidence, that heavy Canadian crude oil will result in heavy sludge in storage tanks. Section 4.6.3 of the DEIR addresses management of sludge generated from storage tanks. The DEIR explains that peak day activities for tank sludge management will remain the same before and after the proposed project. Additionally, the DEIR explains that the sludge will remain on-site to be processed as DCU feed (i.e., recycled on-site), therefore no increase in waste disposal would be expected from the proposed project. Response G1-78.146 compares various heavy crude oils processed by the Refinery and illustrates that the properties of heavy Canadian crude oil are similar to those of other heavy crude oils purchased, stored, and blended for processing by the Refinery. Therefore, heavy crude oil storage tank sludge generated from various existing and new or replacement storage tanks is expected to be similar.

And, it is important to keep in mind that the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery. Future changes in the Refinery's crude oil slate, if any, will occur independently of the proposed project, and will be based on factors that cannot be predicted, such as the relative cost and availability of different crude oils in the future.

Comment G1-81.6

- **Project elements have the potential for much higher emissions and impacts** due to the extraordinary storage tank expansion, expansion of desulfurization equipment, extensive heater, boiler, and incinerator expansion (about 22), at least a dozen new connections of equipment to flares, new railcar imports of liquefied petroleum gas, and more.] G1-81.6

Response G1-81.6

The comment claims that the proposed project has potentially higher emissions and impacts than evaluated in the DEIR. Subsequent comments and responses address these issues in more detail. Response G1-81.39 addresses storage tank emissions. Response G1-81.38 addresses desulfurization equipment expansion. Response G1-81.79 addresses heaters, boilers, and incinerators. Response G1-81.69 addresses the new connections of pressure relief valves to the flare system. Response G1-81.94 addresses how the hazard consequences, including those of LPG, are addressed in the DEIR.

Comment G1-81.7

- **Tesoro flaring emissions are already large and could substantially increase,** due to new pressure relief connections to the flares which have the potential to increase emissions from hundreds to thousands of pounds per day in VOC, SOX, and other criteria pollutant emissions, but which were counted as zero, despite permits directing burning gases in flares, and since gases have no place to go during planned and unplanned shutdowns.

G1-81.7

Response G1-81.7

Response G1-81.69 addresses the new connections of pressure relief valves to the flare system. As explained in Master Response 15, data for the Refinery shows that flaring events happen independently of the number of PRVs or the amount of crude oil processed. Between 2007 and 2015, approximately 90 PRVs were newly connected to the Refinery flare and flare gas recovery system. As further described in Mater Response 15, the emissions from flaring have decreased over the same time period and have no correlation to increasing number of PRVs connected to the flare and flare gas recovery system. Responses G1-81.69 through G1-81.78, Master Response 15, and Response G1.78.207 explain in detail that the proposed project is not expected to result in increased flaring emissions.

Comment G1-81.8

- **Heater and Boiler use would be greatly expanded, but was found in some cases to *decrease* emissions despite maximum heat input limits increasing,** without a clear basis, sometimes leaving out best technology assessment.

G1-81.8

Response G1-81.8

Response G1-81.79 addresses the increases and decreases in the use of heaters, boilers, and incinerators and notes that the proposed project results in overall reduction of 451.6 mmBtu/hr of heater duty. Responses G1-81.81 and G1-78.204 explain the proposed permit modifications increasing the described duty of the DCU H-100 heater and imposing conditions to ensure that emissions after the proposed project is implemented will not increase above recent operating levels.

Comment G1-81.9

- **Pipeline spills have a greater potential and the DEIR should add evaluation**, and the status of the pipeline expansion from 12 to 42 inches proposed in 2014, and connections of miles of pipelines of Tesoro acquisitions to the airport and other locations should be disclosed and evaluated.

G1-81.9

Response G1-81.9

Response G1-81.89 provides the status of the pipeline replacement associated with the proposed project which will be from 12 to 24 inches.

The rest of the comment refers to Tesoro Logistics acquisitions, which are the transfer of assets from one Tesoro entity to another. Response G1-81.96 explains the asset transfer, which also includes the pipeline to the airport. No pipeline connections were required or made as part of the asset transfer. The asset transfer has no impact on the physical environment or potential operation of the existing storage tanks and pipelines.

Comment G1-81.10

- **The Project should not take credit for the FCCU shutdown,** because the State of California approved the Tesoro purchase of BP Carson despite anti-competitive concerns based on this and other environmental improvements] G1-81.10

Response G1-81.10

As described in Master Response 13, the comment incorrectly claims that the shutdown of the Wilmington Operations FCCU was a condition of approval for Tesoro's acquisition of the BP Carson Refinery and ARCO branded service stations, and therefore, the baseline for air quality impacts should not include emissions from the Wilmington Operations FCCU. Consistent with applicable law, the District properly concluded that the baseline includes the existing operation of the Wilmington Operations FCCU. The Federal Trade Commission and the California Attorney General both reviewed Tesoro's proposed acquisition to ensure that the acquisition would not violate federal and state antitrust laws. After a nine-month review, on May 17, 2013, the agencies announced that they had resolved any potential antitrust concerns with the proposed acquisition.

During the antitrust review process, Tesoro submitted documents to the FTC and the California Attorney General stating that Tesoro intended to make certain modifications at the combined Refinery that would allow Tesoro to achieve specified "synergies" between the Wilmington and Carson Operations. Among other changes, Tesoro explained, Tesoro planned to replace some of the combined Refinery's fluid catalytic cracking unit ("FCCU") capacity with additional hydrotreater capacity.

In connection with her approval of the acquisition, the Attorney General entered into an agreement with Tesoro. In this agreement Tesoro agreed to maintain CARBOB capacity for three years, maintain the ARCO brand, and not eliminate jobs for a period of two years. Tesoro also agreed to provide an annual report on the actions taken to achieve the specified synergies, including actions designed to replace FCCU capacity with hydrotreater capacity.[247]

[247]See Attachment E, Kathleen Foote for Kamala Harris, letter to Robert Weisenmiller, May 17, 2013. In the letter, the Attorney General uses the term "distillate desulfurization unit" to refer to additional hydrotreating capacity.

Thus, it is not accurate to say that the Attorney General required Tesoro to shut down the Wilmington Operations FCCU as a condition of approval. Rather, the Attorney General required Tesoro to provide an annual report on the implementation of Tesoro's existing plans to modify the combined Refinery by, among other things, replacing FCCU capacity with hydrotreater capacity. Moreover, operation of the Wilmington Operations FCCU is part of the baseline environmental conditions and the proposed project enables the Wilmington Operations FCCU to be shutdown.

As explained in Section 4.2.2.2 and Table 4.2-4 of the DEIR and Master Response 13, emission reductions are appropriately credited to the proposed project. Further information about the purchase of the BP Carson Refinery by Tesoro can be found on Page 2-1 of the DEIR. Section 4.2.2.2 of the DEIR explains that the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. The proposed project will result in local reductions in GHG emissions as discussed in Section 5.2 of the DEIR and as summarized in Table 5.2-8 (see page 5-26 of the DEIR).

Comment G1-81.11

- **Special attention is needed for earthquake and related fire risks due to the Project** because of the large new storage tanks, pipeline expansions, LPG by rail, increased risk of hazardous chemical release. G1-81.11

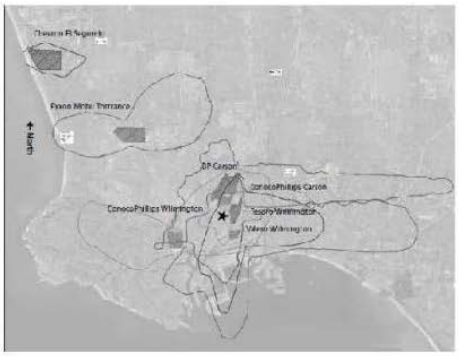
Response G1-81.11

Response G1-81.94 explains in detail that the DEIR thoroughly evaluated hazardous material releases and that the consequence of a hazardous materials release would be the same irrespective of the cause (i.e., including earthquakes) of the release. It should be noted that the DEIR assumed that releases of flammable materials would be ignited, as a worst-case scenario (see Sections 4.3.1 and 4.3.2.1 of the DEIR that explain significance criteria including flash fire and radiant heat from a pool fire). Also see Master Response 9 for additional information regarding ignition of releases of flammable materials.

The letter notes that replacing FCCU capacity with "desulfurization" capacity will benefit the environment by reducing emissions and greenhouse gases.

Comment G1-81.12

- **Cumulative Impacts should be changed to significant because the DEIR impermissibly took credit for large emissions reductions from the SCIG** (Southern California International Gateway) project even though the AQMD won a challenge that resulted in the SCIG EIR being invalidated in court. The AQMD website also describes this project as having increased emissions that impact many communities, rather than providing emissions reductions.



Cumulative or piecemealed impacts of extensive interrelated projects and issues in the region and additional issues should be identified and evaluated including:

- 16 miles of pipelines, storage, and export of fuels to Los Angeles International Airport,
- Modifications and interrelation with Tesoro Logistics operations (since Tesoro sold many facilities for gathering, moving, storing, and distributing petroleum inputs and products to Tesoro Logistics, and since company literature identified synergies between Tesoro refining and Tesoro Logistics),
- Hydrogen production from companies such as Air Products that sell to Tesoro,
- Evaluation of San Pedro butane tanks relation to the Tesoro Project.

G1-81.12

Response G1-81.12

Response G1-81.95 explains in detail that the conclusion in the DEIR that the operational emission impacts of the proposed project are not cumulatively significant and did not rely upon the emission reductions reported in the SCIG EIR.

The suggestion in the comment that former Tesoro activities were cumulative or piecemealed projects is duplicated with additional detail in Comment G1-81.96. None of the activities are cumulative or piecemealed projects as explained in detail in Response G1-81.96.

Comment G1-81.13

- **The Environmental Justice (EJ) setting and implications of all the above Project and Cumulative impacts require much more attention and compliance with AQMD and EPA EJ policies,** given the disproportionate burden due to the heavy industrialization in the area and the high levels of asthma and other health impacts

Minding the Climate Gap - Top 10 Facilities Polluting Disproportionately in Communities of Color

Rank	Facility Name	City
1	BP Carson Refinery	Carson
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)
3	Paramount Refinery	Paramount
4	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)
5	ExxonMobil Torrance Refinery	Torrance
6	Chevron Richmond Refinery	Richmond
7	Malburg Generating Station (Vernon Power Plant)	Vernon
8	ConocoPhillips Carson Refinery	Carson
9	Valero Wilmington Refinery	Wilmington (Los Angeles)
10	California Portland Cement Company Colton Plant	Colton

G1-81.13

Response G1-81.13

Master Response 14 and Response G1-81.97 address the issue of environmental justice in detail.

Comment G1-81.14

Summary of recommendations for necessary DEIR additions (detailed in this Report):

The DEIR should provide baseline data and projected changes including:

- The crude oil slate (specific crude oil use and characteristics), throughput, and storage in specific tanks, including Bakken and Canadian crudes,
- The total refinery, distillation unit, and coker daily throughput,
- Sales of Tesoro LA refinery fuels inside and outside California, and outside the U.S.,
- Desulfurization capability and sulfur mass,
- DCU Heater H-100 and other project heaters daily and annual heat input and emissions,
- Third party transfers including Tesoro LA refinery products ultimately stored in San Pedro butane tanks, hydrogen purchases by Tesoro (Air Products and other), Tesoro product exchanges with Tesoro logistics, the Los Angeles Airport, and others.
- Marine terminal crude delivery by ship volume, characteristics, and projected changes

G1-81.14

Response G1-81.14

The comment includes a summary of claims that baseline data and projected changes for the topics listed in Table 81.14-1 are required in the DEIR. The topics raised in the comment and responses are detailed in subsequent comments and responses as indicated in Table 81.14-1.

Table 81.14-1

Topics Raised in Comment and Location of Responses

Topic	Response	
	Master Response Number	Specific Cite or Response Number
Details on Crude Oil Stored and Processed	4, 6, and 12	G1-81.42, and G1-81.101 through G1-81.103
Refinery, Distillation Unit and DCU Throughput	4, 6, 12, and 17	DEIR Section 2.5.4.1 and G1-81.101
Product Sales Information (CA, U.S., International)	12	DEIR Section 2.2, G1-81.38, and G1-81.104
Desulfurization Capacity	4 and 12	G1-81.31, G1-81.38, G1-81.105
Proposed Project Heater Data	12	DEIR Sections 4.1.1 and 4.1.2, G1-81.79, G1-81.81, G1-81.83, and G1-81.85 through G1-81.87
Third-Party Transfers Including: Hydrogen Purchases, Product Exchanges with Tesoro Logistics, Including LAX	-	G1-81.96, G1-81.118, G1-78.171, and G1-78.176
No Refinery Storage at Rancho LPG	10	G1-81.96
Marine Delivery Details	6 and 12	G1-81.28 and G1-78.176

Note: - = No Master Response prepared on this topic.

Comment G1-81.15

The DEIR should also evaluate the following and make corrections:

- A complete Environmental Justice evaluation of the human and environmental setting, and potential increased burden due to the additional impacts listed below
- The full potential to emit due to flare emissions during planned and unplanned shutdowns, maintenance, "essential operating needs" allowed by the AQMD Rule 1118.
- Corrected heater emissions showing increased emissions with increased utilization.
- Corrected Project emissions by subtracting FCCU shutdown emissions, previously required by the State of California.
- Evaluation of potential local impacts due to use of Bakken and Canadian crudes in the refinery including increased corrosion, explosion risk, benzene, hydrogen sulfide, other toxic components and byproducts of processing crude oil, increased processing hazards due to increased paraffin introduction, and increased GHGs.
- Potential out of state cumulative impacts due to importing Bakken crude oil and potentially Canadian tar sands crude, including extraction impacts such as GHGs, land, air, and water impacts, and transportation risks.
- GHG emissions due to third parties importing additional hydrogen to the refinery, potential for additional hazards at the San Pedro storage tanks, due to increased use of LPG at the refinery, and hazards due to spills from potential increased ship size
- Interconnection and cumulative impacts of the Tesoro LA refinery with other Tesoro facilities that transfer petroleum materials, including Tesoro Logistics and others

G1-81.15

Response G1-81.15

The comment includes a summary of claims that the DEIR requires revision to address the topics listed in Table 81.15-1. The topics raised in the comment and responses are detailed in subsequent comments and responses as indicated in Table 81.15-1.

The comment raises a general comment regarding potential local impacts including byproducts of processing Bakken and heavy Canadian crude oil. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery processes a crude oil blend and the proposed project does not modify the crude oil operating envelope of the Refinery. Therefore, no additional byproducts or substantial change in the amounts of byproducts produced are expected as a result of implementing the proposed project.

And, it is important to keep in mind that the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery. Future changes in the Refinery's crude oil slate, if any, will occur independently of the proposed project, and will be based on factors that cannot be predicted, such as the relative cost and availability of different crude oils in the future.

Table 81.15-1

Topics Raised in Comment and Location of Responses

Topic	Response	
	Master Response Number	**Specific Cite or Response Number**
Environmental Justice	14	G1-81.97
Flaring	15	G1-81.69 through G1-81.78
Heater Emissions	12	G1-81.79 through G1-81.88
Shutdown of the Wilmington FCCU	13	G1-81.92
Bakken and Heavy Canadian Crude Oil Properties	12	
Corrosion		G1-78.111
Explosion Risk		G1-81.57
Benzene and other TACs		G1-81.39, G1-78.114, and G1-78.157
Paraffins (i.e., Waxy Deposits)		G1-81.54, G1-81.55, and G1-78.162
Bakken and Heavy Canadian Crude Oil GHG Emissions	-	G1-81.65 and G1-81.67
GHG Emissions from Hydrogen Production	-	G1-81.96 and G1-78.171
Rancho LPG	10	G1-81.96
Marine Vessel Size	6	G1-81.110
Cumulative Tesoro Projects	16	G1-81.118 and G1-81.120

Note: - means no Master Response on the topic.

Comment G1-81.16

Additional Alternatives to the Project pooling at least the following public recommendations on safety and lower emissions should be evaluated, including:

- No increased refinery crude throughput
- No storage tank expansions,
- No Bakken or Canadian crude oil in the refinery, set by a permit condition,
- No increased hazards (including from LPG, railcars, H2S, Sulfuric Acid Regeneration Plant, Wet Jet Treater, and many hydrotreaters),
- Additional emissions reductions in the refinery to offset potential increases from flaring, heaters, other sources, and the crude switch.

G1-81.16

- Evaluation of zero carbon alternative energy mitigation measures included to some extent in the 2014 Chevron Modernization Project Revised DEIR, and others

G1-81.16 cont'd.

Response G1-81.16

The suggestion in the comment that specific alternatives to the proposed project should be evaluated is duplicated with additional detail in Comment G1-81.121 and addressed in detail in Response G1-81.121.

Comment G1-81.17

Draft Title V Permit comment summary:

I reviewed the Draft Title V Permit, attached AQMD calculations, and many associated permit applications. In this case the draft permit covers only a subset of the many DEIR Project components, with more pieces of the DEIR Project to be submitted for permits by Tesoro later. For instance, the DEIR tank expansion is not currently part of the Draft Title V Permit, and the District has explained that it has not yet received an application for permits for them.

The Title V permit must await approval until the environmental review (EIR process) is completed, because, for example, the DEIR looks at alternatives to the Project, and the Project could change after the DEIR process.

G1-81.17

Much of this report describes Project deficiencies in terms of DEIR issues, however, because many of these issues are cross-cutting with the draft Title V components, I am submitting this report as comments on the Draft Title V permit as well as on the DEIR. For example, I discussed the Draft Title V Permit covers heater expansions and additional pressure relief device connections in the DEIR context. These should also be considered comments on the Title V Draft Permit, because additional emissions are not fully identified, and permit conditions are not set to preclude these emissions. **Emissions reductions and permit conditions should be added addressing these missing emissions increases.**

Response G1-81.17

The comment correctly notes that the draft Title V Permit covers only a subset of the proposed project components, because permit applications have not yet been submitted for all the proposed project components. The comment further correctly states that approval of the Title V permit must wait certification of the FEIR by the SCAQMD.

The comment additionally states that the comment letter serves as comments to the draft Title V permit as well as the DEIR. The comment letter contains no specific comments with respect to

the Title V permit equipment descriptions, conditions, or evaluations conducted pursuant to SCAQMD's Regulation XXX, and therefore, specific responses to Title V issues are provided in the following Responses. The comment simply suggests that there are additional emissions associated with equipment modifications and that permit conditions should be added to address the additional emissions.

Subsequent comments and responses address in detail the heater and flare issues raised with respect to the DEIR analysis. See Comments and Responses G1-81.68 through G1-81.88 for the detailed claims and descriptions that the DEIR appropriately analyzed emission changes associated with the proposed project. Therefore, no additional Title V permit conditions are required.

Comment G1-81.18

In addition, the switch to different crude oils (Bakken, and potentially Canadian Tar Sands) is not acknowledged as part of the Project in either the DEIR or the Title V discussion. This is a far reaching change, so impacts of this switch which would impact equipment throughout the refinery are missing from the Title V evaluation. **If the Title V changes leave out discussion of the crude oil switch, then permit conditions should be set prohibiting increased use of Bakken or Canadian crude oil above baseline levels, with data provided establishing this baseline.**] G1-81.18

Response G1-81.18

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing blends of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Therefore, no additional Title V permit conditions are required.

Comment G1-81.19

Furthermore, because much baseline data is missing and the increases above the baseline have a large potential for significant increased emissions due to this project, the Title V permit conditions cannot be considered sufficient to prevent these increases.] G1-81.19

Response G1-81.19

The comment is not specific to which baseline data would need to be considered in Title V permit conditions. The DEIR fully evaluated potential impacts of the proposed project compared to baseline. The draft Title V permits correctly evaluated the post-project PTE compared to the pre-project PTE. To the extent baseline issues were identified in the comment letter, Response G1-81.14 identifies where detailed responses on the various issues are located.

Comment G1-81.20

II. Tesoro's stated purpose to investors is competitive advantage, connecting West Coast assets, bringing price-advantaged crude to LA through Vancouver Washington, and increasing flexibility for gasoline and distillate tradeoff

This section identifies inconsistencies and flaws in the DEIR regarding the fundamental nature of the Project, showing conflicts between Tesoro officials' statements, and DEIR statements, in the refinery size, especially regarding a switch to different crude oils that have many new impacts, and other Project Description flaws that relate to significant impacts.

Because of clear, and stated connections and plans of the Tesoro corporation regarding the switch to bring a large portion of N. Dakota Bakken (and potentially a substantial volume of Canadian crude) to the Tesoro LA refinery, both Tesoro and the environmental review process (first the Negative Declaration, now the DEIR), lose credibility in continuing to deny any connection to the Project. This reality needs to be simply stated, and evaluated. Mitigation, alternatives, and permit conditions should be proposed. If not, permit conditions should be set requiring that no Bakken crude oil or Canadian crude oil will be allowed in the new tanks or freed up capacity in existing tanks.

G1-81.20

G1-81.20 cont'd.

Response G1-81.20

This is a summary comment of the specific comments to follow in this section of Comment Letter 81. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Response G1-78.94 also clarifies that it is correct to say that Tesoro makes ongoing efforts, evidenced by its corporate statements, to provide "advantaged crude oil" to each of Tesoro's U.S. refineries (see Master Response 4 for a description of "advantaged crude oil" as that term is used by Tesoro).

Comment G1-81.21

A. Even the size of the refinery is in question, and has major undisclosed impacts

The DEIR states:

> *"The total crude oil rate capacity for the Los Angeles Refinery is **363,000 bbl/day.**"*[6]

Tesoro on the other hand states:

> *"The Los Angeles refinery is the largest refinery on the West Coast and is a major producer of clean fuels. At full capacity, it operates at **380,000** barrels per day (bpd)."*[7]

This is a major difference in description of a basic and fundamental refinery characteristic – its size. This impacts all aspects of the Project, since the refinery takes the crude oil, separates components in the distillation units, then cracks a portion of this, sends a portion to the cokers, alkylates portions, reforms portions, hydrotreats high sulfur portions, blends portions, etc. This means that everything in the refinery could be processing larger volumes than the DEIR has evaluated, and it begs the questions:

- Has the refinery already increased its throughput before it received approval?
- Why does the DEIR identify a potential increase from 363,000 bpd, plus 6,000 bpd (ostensibly to 369,000 bpd identified in the DEIR), when Tesoro has aims to reach a higher refinery throughput level of 380,000 bpd
- If Tesoro will be increasing from 363,000 bpd to 380,000 bpd, what other changes will occur in the refinery?
- Are there intermediate products imported to the refinery, where do they come from, what are they, and are they part of this size discrepancy?

G1-81.21

Generally, oil refinery capacity is described in terms of the amount of crude oil processed first in distillation units at the refinery front end. Crude oil is the main source of inputs at the refinery, but it is also common for oil refineries to purchase some amount of intermediate product that can be input downstream of distillation units.

This could mean that the Project will increase from 363,000, to 380,000, which is 17,000 additional barrels per day, almost three times the described increase of 6,000 barrels (which is in itself a significant increase). The DEIR cannot proceed until the basic facts of refinery size are identified. The implications are numerous, and too far reaching to assess in the allotted comment period, so the DEIR needs to be corrected. This will require documentation of the baselines of the individual Wilmington and Carson crude and intermediate product inputs from before the purchase of BP Carson by Tesoro, to the present.

CBE asked Tesoro representatives about the difference between the discrepancy. Tesoro representatives stated that the refinery size has to do with the rated capacity and reporting to government entities, using the Solomon evaluation for sustained operating rate.[8] The DEIR should provide this data, and publicly establish the baseline used, and the potential increase in crude oil throughput for the Project.

G1-81.21 cont'd.

[6] DEIR at p. 2-17, emphasis added

[7] Los Angeles Refinery Fact Sheet 2016, Tesoro, https://tsocorpsite.files.wordpress.com/2016/04/tesoro-los-angeles-fact-sheet.pdf emphasis added, Attachment 1

[8] 6/1/2016 meeting of CBE and Tesoro by telephone and webex presentation of Tesoro LARIC project.

Response G1-81.21

The majority of the points in the comment regarding the crude oil capacity of the Refinery have been addressed in prior comments. Master Response 5 and Responses G1-78.142, G1-78.187, and G1-78.208 describe in detail that the rated capacity of the Refinery is 380,000 bbl/day. The proposed project does not enable the Refinery to achieve this capacity. The reported capacity of

380,000 bbl/day has already been achieved by the various individual crude processing units in the Refinery. The difference between the 363,000 bbl/day stated in the DEIR and the 380,000 bbl/day (a difference of 17,000 bbl/day) in the SEC 10K filing is not an increase due to the project but reflects two different time periods used to evaluate the Refinery's capacity that have already been achieved. The current Refinery capacity of 380,000 bbl/day is noted in the FEIR. Master Response 6 addresses the potential crude oil capacity increase of 6,000 bbl/day that was appropriately evaluated in the DEIR.

The comment raises the issue of intermediate feedstocks that are imported by the Refinery. As described in the DEIR (page 2-2), "The proposed project will have a small impact on crude oil and feedstock capacity. The crude oil and feedstock processing capability at the integrated Refinery will increase approximately two percent or 6,000 bbl/day as a result of the proposed project." The 6,000 bbl/day potential feed (crude oil and intermediate feedstocks) capacity increase is associated with the DCU H-100 heater permit revisions that were analyzed in the DEIR. Any increase in intermediate feedstock processing throughput that may be part of the 6,000 bbl/day increased feed processing capacity will displace additional crude oil capacity such that the total additional feed processing rate would not exceed 6,000 bbl/day. An increase of 6,000 bbl/day crude oil capacity was evaluated in the DEIR because the impacts from an increase in crude oil capacity will result in greater environmental impacts downstream of the DCU than any feedstock. Feedstocks are subject to the same downstream unit processing constraints as crude oil. Therefore, any impacts associated with a small, less than 6,000 bbl/day, increase in feedstock processing capacity have been evaluated in the DEIR.

The DEIR also addresses processing of intermediate feedstocks in downstream process units, particularly the Carson and Wilmington Operations FCCUs. By shutting down the Wilmington Operations FCCU, the proposed project will enable the Wilmington Operations to consistently provide gas oil feed to the Carson Operations FCCU. This enables the Refinery to discontinue or reduce purchasing gas oil from third-party sources in order to keep the FCCUs operating near capacity (see page 4-2 of the DEIR).

The comment also claims that the DEIR should provide data regarding the Carson and Wilmington Operations crude oil and intermediate feedstock data and Solomon evaluations. Master Response 2 addresses the fact that this is trade secret, confidential business information and further, the SCAQMD did not rely on any of this information in the required analysis pursuant to CEQA (see Response G1-78.94).[248] Therefore, the suggested information is not necessary to evaluate the proposed project's impacts, was not relied on or provided to the SCAQMD, and need not be provided.

[248] In order to perform his evaluation, Dr. McGovern, the SCAQMD's refinery expert consultant, was provided with trade secret, confidential business information related to the Refinery including process unit information, crude oil blend properties processed by the Refinery, Linear Program runs and data, and details on design of the proposed project.

Comment G1-81.22

Despite Tesoro's stated purpose to investors, the DEIR shows a disappointing avoidance of the overwhelming and straightforward evidence regarding this key Project element: -- the crude oil switch. This is a stated, fundamental basis for the Project, according to Tesoro's own consistent statements from 2013 to the present (when Tesoro officials speak outside the DEIR proceedings).

In contrast, *other* Tesoro officials, when speaking in the context of the DEIR process where Tesoro seeks Project approval, Tesoro describes the Project purpose as reducing emissions, and making the refinery more efficient (at the AQMD public hearing May 17th, in written Public Relations documents, and in community meetings).

Unfortunately, the DEIR description follows suit, and its conclusions are more in line with Tesoro's public relations descriptions, rather than providing an unbiased and independent investigation required by California environmental laws in the DEIR. It states: *"While the proposed project does not affect the types of crude oils processed at the Refinery and, thus, will not have impacts due to changes in crudes, the proposed project may increase downstream unit processing rates on a monthly or daily basis."* (for example at p. 4-2)

G1-81.22

Tesoro statements to investors, unlike the DEIR, describe the Los Angeles refinery Project, the crude oil switch, and the Vancouver Energy project as follows:

> "**When you think about formalizing competitive advantage and fully integrating our value chain, that is really what the Los Angeles Integration and Compliance Project is about.** And when we think about creating value, we are not just thinking about advantaged crude oils in front of our refineries, **but we're thinking about how that supply to the west coast of advantaged crude oils can change the shape of the crude oil supply/demand dynamics for the west coast. And that's what we are trying to accomplish through Vancouver Energy."**[9]

In contrast, the DEIR states: *"The type of crude oil and feedstocks will not change as part of the proposed project. Crude oil and oil feedstocks are currently obtained from a variety of sources based on factors such as product availability and market conditions."* (For example, DEIR at p. 2-2) The fact that crude oil and feedstocks are obtained from a variety of sources according to market conditions is true, but irrelevant to the fact that Tesoro has stated plans to change the crude, build large crude storage tanks, and make other changes as part of the Project which have major impacts.

Many Tesoro 2016 statements to investors directly connect the LA Refinery integration project with its West Coast crude oil supply project – the Vancouver Energy Project, and identify this as the most efficient route to the West Coast for Bakken crude oil, including these Tesoro slides:[10]

G1-81.22 cont'd.

[9] Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 09, 2015, p. 10, available at http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations Attachment 2
[10] Tesoro Presentations webpage, weblink: Morgan Stanley Corporate Access Day, 5/12/16, Slideshow entitled: *Driven to Create Value, Morgan Stanley Refining Corporate Access Day, May 2016*, Slide 13 &15, available at: http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations , Attachment 3

Response G1-81.22

The claims in the comment alleging that Tesoro's corporate statements to investors reflect a different project objective, i.e. to change the crude oil blend processed by the Refinery, use corporate statements that are taken out of context. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery. The comment pieces together unrelated statements and draws an incorrect conclusion. The quotation is from an Analyst and Investor Day presentation. As described in Attachment C, the Declaration of Douglas Miller,[249] it is important to note that analyst and investor discussions present a high level overview of strategic projects that Tesoro plans to implement at the time of the respective presentations. In fact, just prior to the selected quote, Keith Casey (Tesoro's Executive Vice President, Operations) stated, "Now, as I told you, I also get to update you on some strategic projects, and we have talked about a few of these for the last bit, but really give you some news on the exciting progress that we are making on each of these."[250] Clearly, Mr. Casey is talking about more than one strategic project. Simply because the projects are summarized together in an overview is not an indication that the projects are related. The quotation references two separate projects—the proposed project and the Vancouver Energy Project—as each helping Tesoro accomplish general corporate goals, but the speaker never links the two projects together or states that Tesoro has plans to change the crude oil slate at the Refinery. The proposed project will not result in a significant change in the crude oil blend processed by the Refinery except as analyzed in the DEIR.

Similarly, the slides cited in Footnote 10 are updates of several proposed investments planned by Tesoro Corporation. The planned investments (the proposed project, the Vancouver Energy Project, and the West Coast Mixed Xylenes and Anacortes Isomerization Projects) are not related simply because they are listed on the same "big picture" slide entitled "Strategic Investments for Distinctive Value." (This is slide 13 of the Morgan Stanley Refining Corporate Access Day Presentation.[251]) Each of the bullet items on slide 13 represent separate, unrelated strategic investments, and the subsequent 4 slides in the Presentation (slide numbers 14, 15, 16, and 17) dedicate a slide to each specific strategic investment to explain the strategy and value of each, independent investment. Providing only the two slides in the comment, without the context of the Presentation slides that immediately follow them, removes the context of the separate strategic investments presented at the Morgan Stanley conference. When reviewing the slides shown in the comment in context with the omitted Presentation slides (see Figure 81.22-1), it is clear that the presentation is describing four separate and distinct strategic investments. Master

[249] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.
[250] Thomson Reuters Streetevents Edited Transcript, TSO- Tesoro Corporation 2015 Analyst and Investor Day, December 9, 2015, 2:00PM, at page 10.
[251] Morgan Stanley Refining Corporate Access Day Presentation http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NjMzNDYwfENoaWxkSUQ9MzM4NDAyfFR5cGU9MQ==&t=1.

Response 8 and Response G1-78.139 describe in detail that the Vancouver Energy Project is unrelated to the proposed project.

Strategic Investments for Distinctive Value

- **Creating advantage through integration**
  - Los Angeles Refinery Integration and Compliance Project
- **Changing** the West Coast crude oil supply dynamics
  - Vancouver Energy Project
- **Capturing higher margins** in a high growth market
  - West Coast Mixed Xylenes Project
  - Anacortes Isomerization Project

13 | Tesoro

Creating Competitive Advantage at the Los Angeles Refinery

Los Angeles Integration and Compliance Project

- Completes full integration of Los Angeles Refinery
- Provides 30 to 40 MBD of **gasoline and distillate yield flexibility**
- Improves intermediate feedstock **flexibility**
- **CO_2 emissions reduced** over 300,000 tons annually[1]
- Reduces NOx, SOx and CO emissions

Estimated Project Details

- CAPEX $460 million
- EBITDA $100 million
- IRR 20%[2]

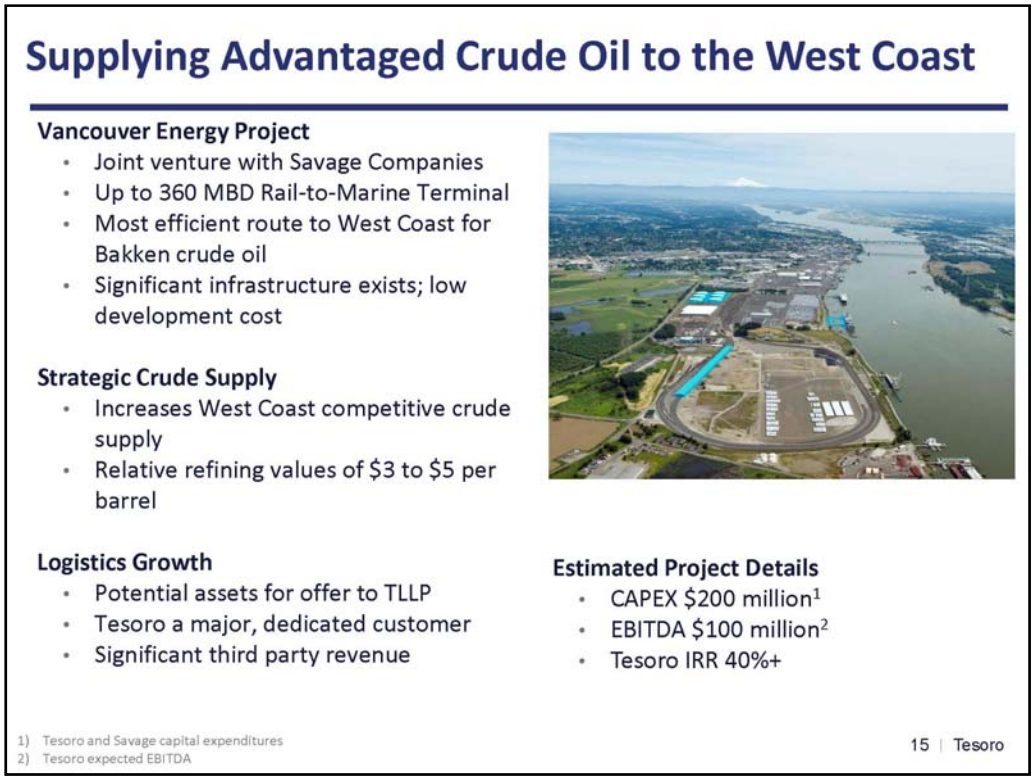
Enhancing West Coast competitive position

1) CO2 reduction associated with expected operations
2) Includes benefits from capital avoidance

14 | Tesoro

Figure 81.22-1a

May 12, 2016 Morgan Stanley Refining Corporate Access Day Slides 13 and 14



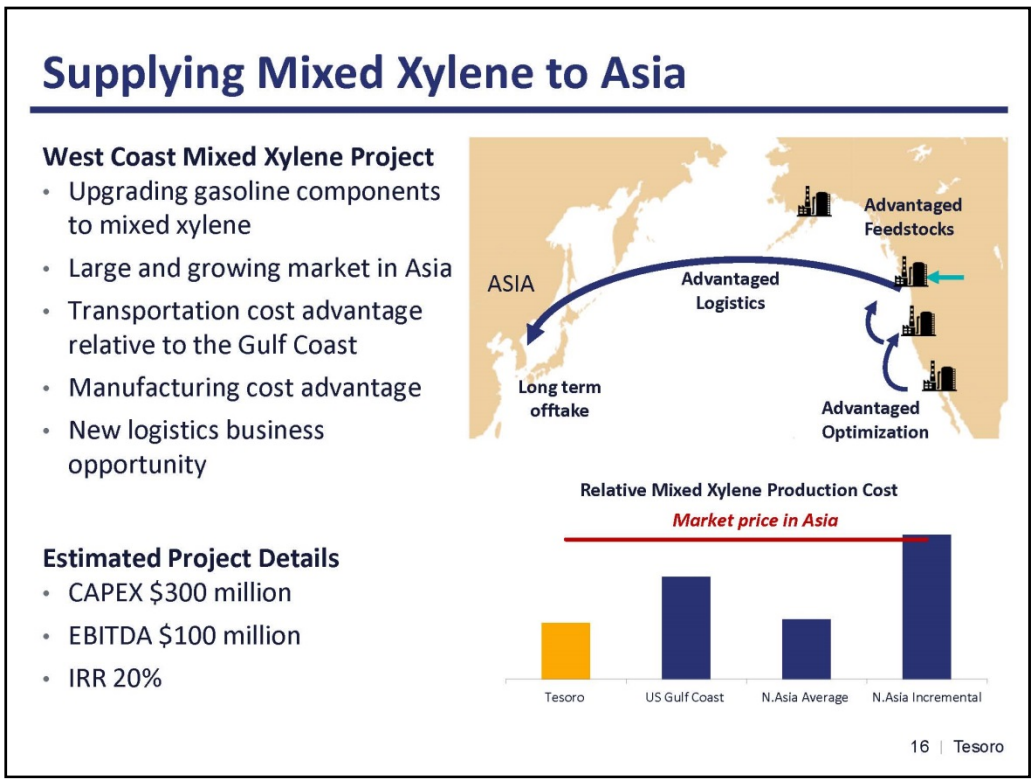


Figure 81.22-1b

May 12, 2016 Morgan Stanley Refining Corporate Access Day Slides 15 and 16

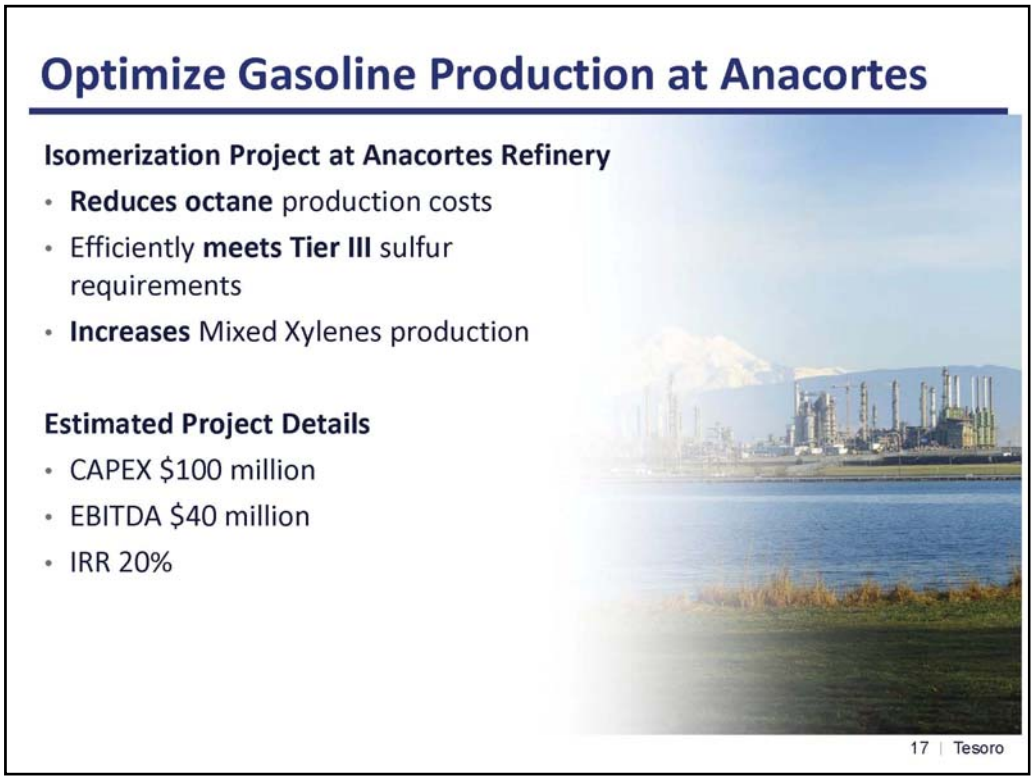


Figure 81.22-1c

May 12, 2016 Morgan Stanley Refining Corporate Access Day Slide 17

Comment G1-81.23

Other Tesoro Project Descriptions differ according to audience.

- **Tesoro's Public Description:** Emphasizes "Cleaner More Efficient Operations"[11]
- **Investors Description:** Emphasizes competitive advantage of connecting assets and moving crude oil on the West Coast

G1-81.23

Tesoro Public Relations Project Purpose description:[13]
"Tesoro plans to invest $460 million to physically connect, further integrate and upgrade our adjacent Carson and Wilmington facilities, so that our combined Los Angeles Refinery operates more cleanly and efficiently. "Pending permitting and approvals, the Los Angeles Refinery Integration and Compliance (LARIC) project will improve air quality, substantially reduce local emissions, upgrade refinery equipment and provide significant benefits to the local economy."
Contrasts with Tesoro description to investors regarding new crude oil access:[14]
"When you think about our portfolio, with almost 740,000 barrels a day of capacity on the west coast, we have a very large and competitive position . . . four excellent refineries with just absolutely superb waterborne logistics connectivity, **so not only for crude oil, advantaged crude oil access up and down the coast . . .** **"This is the Los Angeles Integration and Compliance Project, and, boy, it has been a pleasure. . . . this business is performing very, very well this year and it is going to contribute -- that region will contribute onwards of $2 billion of revenue to our 2015 results** ". . . And then, we do two large pipelines, 45-inch bores going under two major transportation corridors, and I think all totaled it is something like 18 miles of pipe that we are putting in in these projects that will formally connect and unleash the full power of a full integrated site, and that's the exciting thing about this project.

G1-81.23 cont'd.

[11] http://www.tesorolaproject.com/aboutlaric/
[13] http://www.tesorolaproject.com/aboutlaric/ In addition to multiple Tesoro community presentaitons in 2016
[14] Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 09, 2015, previously cited and attached, at p. 8, 11

Response G1-81.23

While Tesoro may emphasize certain aspects of the proposed project when addressing different audiences, none of Tesoro's corporate statements are contrary to the DEIR or to public presentations regarding the proposed project, and the DEIR provides a complete and accurate description of the proposed project, its objectives, and its impacts. The proposed project will enable the Refinery to operate more cleanly and efficiently. By operating more efficiently, the Refinery will also realize economic (competitive) advantages from further integrating the Carson and Wilmington Operations.

However, the corporate statements regarding crude oil access are unrelated to the proposed project. As stated in Response G1-78.94, it is correct to say that Tesoro makes ongoing efforts to provide "advantaged crude oil" to each of its U.S. refineries (see Master Response 4 for a description of "advantaged crude oil" as that term is used by Tesoro). Providing "advantaged crude oil" as used by Tesoro, through the Vancouver Energy Project, to Tesoro refineries, including the Los Angeles Refinery, would occur independent of the proposed project.

The comment puts several unrelated Tesoro corporate statements together and draws an incorrect conclusion. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery. Specifically, the quotes in the comment box titled "Contrasts with Tesoro description to investors regarding new crude oil access:" are taken out of context[252]:

- The first quote refers to existing capabilities and logistics connectivity on the west coast. It should be noted that Tesoro's west coast refineries include the Kenai Refinery in Alaska, the Anacortes Refinery in Washington, and the Martinez and Los Angeles Refineries in California.
- The second quote mixes several different thoughts regarding planning for the proposed project, and the performance of Tesoro's Southwestern Region in 2015.
- The third quote explains potential benefits of a portion of the proposed project scope, including approximately 18 miles of pipe that is associated with the proposed project Interconnecting Piping.

None of these statements are inconsistent or contrary to the DEIR or to public presentations regarding the proposed project. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

Comment G1-81.24

But the DEIR does not find the same air quality benefits as Tesoro: The DEIR finds the Project will also increase VOCs, and have no benefit for NOx, SOx, particulate matter, and Toxic Air Contaminants, but would cut CO emissions.[12] (Furthermore, this report finds that the DEIR has also underestimated true Project impacts.)

G1-81.24

The clear underlying reason for the Project is for the unsurprising purpose of increasing Tesoro profits, including access to cheaper crude oils to use in its integrated refinery. While reducing CO emissions, other emissions will increase (such as VOCs), and many impacts were not evaluated. It is important to clearly state the actual reason for the Project purpose and activities, in order to gain a clear understanding of actual impacts. The DEIR tends to skirt these issues or ignore Tesoro investor statements.

In my 2014 report on Tesoro's Negative Declaration, I quoted similar statements, by Tesoro, and available in oil industry literature, regarding Tesoro's plans. These include connecting its LA refineries to crude oil from the Bakken region and from Canadian tar sands, especially through the Tesoro Savage Washington crude-by-rail to ship terminal, because of the cost advantage:

G1-81.24 cont'd.

[252] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

Morningstar report, July 2013:[15]

Specifically, Tesoro can **dramatically improve the performance of Carson by optimizing its crude slate with light crude from the Bakken.** . . .

Tesoro should gain further advantages from integrating Carson with the Wilmington refinery.

Increasing throughput of light and heavy discount crude from the Mid-Continent and Canada via rail will likely benefit Tesoro more, though. To this end, Tesoro recently entered an agreement to develop a 120 mb/d crude by rail and marine facility in Washington. *[This was expanded to 360,000 bbls/day[16]]*

Tesoro February 2014 slideshow:[17]

"Extending the advantaged crude oil to the West Coast," and changing the Los Angeles operations crude oil feedstock from 15% California Heavy crude to **"Potentially up to 50% California Heavy and Bakken" crude oil** (Slide 13).

"Terminaling, Transportation, and Storage" will "Consolidate Tesoro volumes in Southern California distribution system" and "Open Southern California to third-party business" (Slide 13)

G1-81.24 cont'd.

My 2014 report is attached[18] for reference to additional Tesoro statements and information regarding these plans still relevant to the 2016 Project. While some details may have changed, Tesoro's strategy has not, and Tesoro has reiterated these plans. The plans for integrating the two refineries, shutting down the FCCU, and transporting and storing advantaged crudes, especially Bakken and Canadian crudes to the LA refinery complex, expanding pipelines, remain the same.

My 2014 report included Tesoro's map laying out its plans to transport Bakken crude oil to LA:

G1-81.24 cont'd.

(at p. 9)

Also attached is a separate document I compiled containing many Tesoro quotations about the Project and changes in crude oil (particularly to Bakken) in one place.[19]

[12] DEIR at pp. 4-17 to 4-18

[15] 7/24/2013 http://analysisreport.morningstar.com/stock/archive?t=TSO&region=USA&culture=en-US&productcode=MLE&docId=604033 , emphasis added throughout, Attachment 4

[16] Energy Facility Site Evaluation Council, State of Washington, Tesoro Savage Vancouver Energy Project Application No. 2013-01, DEIS, Chapter 1 excerpt: p. 1-1, *[Tesoro Savage Petroleum Terminal LLC (the Applicant) is proposing to construct and operate the Vancouver Energy Distribution Terminal Facility (the Facility, or the Project) at the Port of Vancouver (Port) in Vancouver, Washington, located on the Columbia River. The proposed Facility would be a crude oil terminal capable of receiving an average of 360,000 barrels of crude oil per day by train, storing it onsite, and loading it onto marine vessels.]* http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20Chapters/DEIS%20Ch%201%20Background-PurposeNeed.pdf Attachment 5

[17] Simmons Energy Conference, *Transformation through Distinctive Performance,* February 27, 2014, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations Attachment 6

[18] *The Proposed Negative Declaration by SCAQMD for the Tesoro Pipeline from its Long Beach Marine Terminal to New Wilmington Refinery Storage Tanks is Missing Major Expansion Plan Descriptions and Requires a Full EIR, Comments of Julia E. May,* Senior Scientist, CBE, June 10, 2014, Attachment 7, also available at: http://www.cbecal.org/wp-content/uploads/2014/08/JMay-CBE-Comments-Tesoro-storage-tank-ND-final.pdf

[19] Tesoro Quotations regarding plans to transport Bakken and potentially Canadian crude oil to West Coast and Los Angeles refinery, compiled by Julia May, June 2016, Attachment 8

Response G1-81.24

As explained in and Section 4.2.2.2 of the DEIR, upon completion, the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. In Table 4.2-4, the DEIR correctly presents the emissions from the proposed project. Tesoro's statements regarding local emission reductions are also accurate; local emissions will be reduced with implementation of the proposed project, including shutting down the Wilmington Operations FCCU. The DEIR evaluated all the impacts associated with the proposed project including the potential air quality impacts (see Section 4.2.2 of the FEIR).

The comment states that the underlying purpose of the proposed project is to increase Tesoro's profits, and the DEIR plainly discloses that improving the financial viability of the Refinery is one of the objectives of the proposed project (see DEIR, page 2-4). But there are multiple objectives that Tesoro seeks to accomplish by the proposed project, such as enabling shutdown of the Wilmington Operations FCCU while maintaining overall fuel production capacity, improving processing efficiency, complying with applicable federal, state, and local regulations, and improving efficiency of water-borne crude oil receipt and marine vessel unloading—those purposes are likewise identified and explained in the DEIR.

Claims in the comment that certain impacts were not evaluated appear to be based on the incorrect assumption that the proposed project will change the crude oil blend processed by the Refinery. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

The comment includes a slide of a map that the comment claims is ". . . Tesoro's map laying out its plans to transport Bakken crude oil to L.A." The map is titled "Rail Costs to Clear Bakken", and shows ranges of costs to transport Bakken crude oil to various locations on the West and East Coasts of the U.S. The map includes a clarifying subtitle "West and East Coasts clearing destinations for Bakken crude oil." There is no reference on the slide or map to any definitive plans to transport Bakken crude oil to any destination, or to any destination in particular or increased amounts.

The comment includes in Footnote 19, reference to Attachment 8 of the comment letter, which is characterized as ". . . containing many quotations from Tesoro about the Project and changes in crude oil . . ." Attachment 8 includes quotes from news articles and statements from Tesoro presentation slides as evidence of the "underlying" purpose of the project described in the comment. Attachment C, the Declaration of Douglas Miller addresses each of the statements and slides in Attachment 8 and explains that the materials do not support an undisclosed intention to increase transportation of Bakken and heavy Canadian crude oils to the Los Angeles Refinery as

a result of the proposed project.[253] Many of the "quotes" in the comment are statements by Tesoro that are taken out of context, use terms misinterpreted by the comments, or quote from news articles or other sources that are not statements by Tesoro. See the Miller Declaration paragraphs 10 through 21 for full responses and descriptions of each item in Attachment 8.

Comment G1-81.25

C. Tesoro Savage Vancouver Washington Terminal, recently given a two-year lease extension, is a key part of Tesoro West Coast plans to bring crude to its refineries, from the Bakken region, with options for Canadian crude

The Tesoro/Savage Vancouver, Washington[20] joint venture *Vancouver Energy Terminal* on the Columbia River is a crude-by-rail to oil tanker terminal. The Vancouver Energy website states:[21]

> Tesoro and Savage formed a joint venture to build and operate the Vancouver Energy terminal, which will accept and **ship crude oil that originates in the midcontinent of North America – including the Bakken formation – at the Port of Vancouver USA via rail.** The crude oil will be temporarily and safely stored in secure tanks, then transferred to customers' vessels, **shipped by customers to West Coast oil refineries,** and converted into transportation fuels and other products for U.S. consumption.

G1-81.25

The Draft Environmental Impact Statement (DEIS) for the Tesoro Savage terminal states:[22]

> The Applicant is proposing to construct and operate a Facility that would receive an average of 360,000 barrels (bbl) of crude oil per day by rail, temporarily store the oil onsite, **and then load the oil onto marine vessels for transport to existing refineries primarily located on the West Coast of the United States.**[2] (at p. ES-2)
>
> . . . While projecting future market conditions is nearly impossible, based on the strength of Bakken production and market conditions known at this time, **it is assumed that the Bakken would be the likely source of the mid-continent North American crude oil delivered to the proposed Facility.**

The DEIS also states:[23]

> **Starting in 2017, the proposed Facility could receive crude oil from any source with rail access to the Port; however, according to information provided by the Applicant, the most likely sources would be northern mid-continent crude oil produced in North Dakota and Montana, and in Canada.** An average of four unit trains per day would arrive at the proposed Facility.

G1-81.25 cont'd.

While Tesoro officials stated in an interview that California permits for the LARIC Project are delayed but expected by the end of this year, the CEO expects the Tesoro Savage Vancouver Energy Project will be ready to go this fall, according to CEO Greg Goff regarding the Vancouver project approval:[24]

> "The hearings are formally set for the end of June through about 30 days, so the latter part of July," he said. "**We expect a final Environmental Impact Statement to be issued this fall, followed by a recommendation to the Governor of Washington**," Goff added.

Despite widespread public opposition to the Project, the lease renewal was granted by the Commission unanimously in April (*Vancouver Port Gives Oil Companies What They Want — More Time*).[25]

(Tesoro also announced purchasing N. Dakota Bakken facilities allowing increased pumping of Bakken crude oil, so the chain of Tesoro acquisitions would extend from N. Dakota, by rail to the Tesoro Savage Terminal in Vancouver Washington, and by ship to the Los Angeles refineries, described later in this report.)

[253] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

[20] Not to be confused with Vancouver Canada, which also has oil terminals on the West Coast.
[21] https://www.vancouverenergyusa.com/
[22] Available at: http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20PAGE.shtml Excerpt as Attachment 9
[23] Tesoro Savage DEIS, Fact Sheet, http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20PAGE.shtml Attachment 10
[24] May 6, 2016, S&P Global: Tesoro cuts 2016 spending on project permitting delays, Attachment 11, ttps://www.linkedin.com/pulse/sp-global-tesoro-cuts-2016-spending-project-delays-janet-mcgurty
[25] Oregon Public Broadcasting (OPB), April 15, 2016, http://www.opb.org/news/article/vancouver-port-oil-terminal-lease-extension/ , Attachment 12

Response G1-81.25

Master Response 8 and Response G1-78.139 explain in detail that the Vancouver Energy Project is not related to the proposed project and the Vancouver Energy Project is proposed to transport crude oil to any West Coast refinery, not just Tesoro refineries and not just the Los Angeles Refinery. Neither SCAQMD nor Tesoro dispute the statements quoted from the Vancouver Energy Project website or the DEIS.

The comment notes a two year lease extension for the marine terminal in Vancouver, Washington. Tesoro reports that the lease for the site for the proposed Vancouver Energy Project was extended eight months, not two years, while the Vancouver Energy Project permitting process continues.

The comment also refers to Tesoro's announcement regarding the purchase of assets, including a pipeline and a storage and rail loading facility, in the Bakken region. Tesoro is a refining and marketing company that does not own or invest in crude oil production fields. Tesoro owns infrastructure and facilities to transfer and process crude oil produced by others. The acquisition of additional assets in the Bakken region is unrelated to the proposed project and was simply an addition to its logistics in the Bakken region. It should be noted that Tesoro owns two refineries, the Mandan Refinery and the Dickinson Refinery, in the Bakken region that refine Bakken crude oil.

Comment G1-81.26

D. A 2014 expert report on the Tesoro Negative Declaration contains still-valid data and analysis confirming Tesoro's Project as a crude switch with significant impacts

A report by Dr. Phyllis Fox, 2014 (attached in full[26]), provided extensive analysis that is still valid regarding the nature of Tesoro's storage tank project as part of a larger set of refinery modifications that would facilitate crude oil slate changes. G1-81.26

The Fox report found for instance that:

- Tesoro's proposed crude oil tank changes would accommodate a switch to North American crude oils including Bakken crude oil (due to the high tank vapor pressure, which would uniquely accommodate Bakken crude see Fox Report, Volatility of Commonly refined crudes:

  > *"Bakken crude oils are the only crude oils that I am aware in the market today that have a TVP of 11 psi. . . . This figure shows that all crude oils that are designated as "light" do not have the same vapor pressure and thus, the same environmental impacts when stored and transported. The more volatile the crude, the higher the VOCs, TACs, and greenhouse gas (GHG) emissions, the higher the flammability, and the greater the consequences in the event of an accident. The only "light"[23] crude oil that Tesoro has admitted to refining at its California refineries in its filings with the U.S. Security and Exchange Commission is in Basrah, an imported Iraqi light crude oil with a vapor pressure that is half that of Bakken."* (pp. 8-9)

- Tesoro's crude storage tank heaters, could also accommodate Canadian tar sands crude:

  > *"Further, the two new 300,000-bbl floating roof tanks (3000035/36) will be equipped with heating coils (3/7/13 Revised Application, pdf 42), which would allow handling heavy tar sands crudes.* (pp. 12-13)

- Tesoro made many statements about its plans to bring North American Bakken and/or Canadian crudes to replace Alaska North Slope crude:

  > *". . . we acknowledge the substitution or partial shift in our crude slate from ANS [Alaska North Slope] and other lower-value feedstocks to more attractive alternatives, such as Mid-Continent North American advantaged feedstocks."* (p. 21)

- Tesoro made many statements about plans to use the Vancouver Terminal to bring crudes to its LA refineries:

  > *"The CEO of Tesoro, Greg Goff, has indicated that the Los Angeles Refinery can take the entire shipment [from the Vancouver Terminal]. There are "no restrictions on how much we can take . . ."* (p. 11)

- Many additional statements of Tesoro, and by the author of the report were included regarding the nature of the Project as a crude oil slate switch.

- Refinery Projects which have already de-bottlenecked the ability to expand processing of high sulfur Canadian Tar Sands crude, by expanding the Wilmington hydrogen plant. Hydrogen is needed for Hydrotreating (which uses hydrogen to strip sulfur contaminants

G1-81.26 cont'd.

Dr. Fox's report, my previous comments on the 2014 Negative Declaration, the evidence I provide in this report, and the abundance of evidence Tesoro has published clearly establish that Tesoro's intention is to change the crude oil slate at the LA refinery, mainly replacing large volumes of the existing slate with Bakken crude oil, with options to bring in significant volumes of Canadian.

G1-81.26 cont'd.

[23] Dr. Phyllis J. Fox, *Comments on the Initial Study and Draft Negative Declaration for the Tesoro Storage Tank Replacement and Modification Project*, June 10, 2014, Attachment 13

Response G1-81.26

The comment claims that the proposed project will facilitate changes to the crude oil slate, as illustrated by allowable properties of crude oil to be stored in the proposed project new and replacement storage tanks, by corporate statements on the topic, and by prior expansion of the Wilmington hydrogen plant. It references and duplicates comments made by Phyllis Fox in 2014

regarding the Negative Declaration associated with the two replacement crude oil storage tanks at the Wilmington Operations. The Wilmington Operations replacement crude oil storage tanks have been incorporated into the DEIR for the proposed project. It should be noted that earlier permits submitted for the storage tanks have been withdrawn by Tesoro and therefore, may not represent the final tank details that are permitted.

Attachment C, the Declaration of Douglas Miller, addresses many of the claims in the comment and explains that many of the "quotes" in the comment are statements by Tesoro that are taken out of context or are quotes from news articles that are not statements by Tesoro.

Most of Phyllis Fox's comments cited have also been included in Comment Letter 78, and are responded to as indicated below:

Comment Bullet 1: See Responses G1-78.125 and G1-78.131 that explain that Tesoro used the crude oil vapor pressure allowable by SCAQMD Rule 463 (approaching the TVP limit of 11 psia) for the permit limit to provide operating flexibility and to assess worst-case impacts. See Response G1-78.152 for a description of other light crude oils stored and processed by the Refinery that have vapor pressures in the range of Bakken crude oil.

Comment Bullet 2: Permit applications for the two replacement crude oil storage tanks at the Wilmington Operations were withdrawn by Tesoro. As explained in Response G1-78.157, the replacement crude oil storage tanks were analyzed in the DEIR based on a worst-case hybrid analysis of crude oil properties currently and potentially processed at the Refinery, including Bakken and Canadian crude oil. Heating coils in any storage tank are used when handing heavy or viscous materials, such as heavy gas oil, one of the commodities proposed to be stored in the replacement storage tanks, but would not be used when handing light crude oils. The maximum allowable TVP limit of 11 psia applies to all petroleum storage tanks, including heated storage tanks. Because the storage tanks were analyzed based on worst-case crude oil properties including a crude oil vapor pressure approaching the SCAQMD Rule 463 TVP limit of 11 psia, there would be no additional impacts that were not analyzed in the DEIR, associated with use of heating coils in the replacement crude oil at the Wilmington Operations.

Comment Bullet 3 See Response G1-78.94 that acknowledges Tesoro's continuing efforts to provide "advantaged crude oil," as that term is used by Tesoro, to its U.S. refineries, and Master Response 4 that explains the meaning of references to bringing "advantaged crudes" to Tesoro refineries.

Comment Bullet 4 The comment cited includes an incorrect reference that implies the Los Angeles Refinery is associated with a statement made during Tesoro's First Quarter of 2014 conference call (see Comment Letter G1-81 Attachment 13, page 11). The actual statement made during the call is,

"There is no restriction[s] on how much we chose to move to Vancouver, Washington and then supply our West Coast system." There is no reference to the Los Angeles Refinery, and the statement does not indicate that the Refinery can take an entire shipment from the Vancouver Energy Project when it is completed. See Response G1-78.141 for a description of this statement.

Comment Bullet 5 The comment bullet is vague and unsupported by facts. It refers to "many additional" comments by Tesoro and the author of the report (Phyllis Fox). Because the comment bullet lacks specificity, a specific response cannot be prepared. Responses to all Phyllis Fox's comments referenced in the comment letter on the proposed project are provided in Responses G1-78.92 through 258.

Comment Bullet 6 See Response G1-78.148 for a description of the activities associated with resuming operations of the Wilmington Operations Hydrogen Plant. Contrary to the statements in the comment, the Hydrogen plant was not de-bottlenecked or expanded, it was merely returned to service. The Hydrogen Plant was in operation during the baseline period, and therefore, was part of the baseline and not part of the proposed project or any other project that required consideration as a cumulative impact.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to , and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

Comment G1-81.27

The DEIR attached a report (the McGovern Report[27]) which it used as evidence that there will be no crude oil slate change, or perhaps that, if there is a slate change, it is unrelated to the Project. The McGovern Report provides generalized descriptions of refinery operations and crude oil and some particulars about the Tesoro Project, but it does not address many key particulars of the Tesoro Project that will cause significant impacts. It appears the McGovern Report was developed without access to Tesoro's stated plans specifically to import Bakken crude oil. It also contains some statements that are contradicted by the DEIR or other information. Furthermore, it accepts at face value many conclusory statements provided by the DEIR, without exploration (many statements are prefaced by "it is expected that" or similar statements). G1-81.27

[27] DEIR, Appendix F, SJ McGovern Report for South Coast Air Quality Management District, Tesoro Los Angeles Refinery Integration and Compliance Project. Dr. Stephen J McGovern, PE, October 12, 2015

Response G1-81.27

Response G1-78.103 describes Dr. McGovern's qualifications and the purpose of the McGovern Report. Specifically, Dr. McGovern independently analyzed the individual proposed project elements and concluded that "The changes being made as a result of this project will not allow

the refinery to process a different slate of crude oil." See Master Response 4 for a summary of Dr. McGovern's conclusions. No specific details on the claim that the McGovern Report contradicts the DEIR are provided, so no specific responses can be provided. The McGovern Report does not contradict the DEIR; it provides an independent analysis of the proposed project elements and the DEIR relies, in part, on the Report to conclude that the proposed project will not change the crude oil blend processed by the Refinery (see Sections 2.5.3 and 2.5.4 of the DEIR).

Comment G1-81.28

The McGovern Report cannot be used by the DEIR to avoid evaluation of impacts of changes in the crude oil slate to the refinery, because of the following problems:

►**Throughout, it bases its conclusions on generalized ranges, rather than specific baselines.** For instance, though a range of crudes could be processed at the refinery, the specific crudes in question are not now processed at the refinery in any quantity, but would be after the Project is carried out, causing significant impacts. But the McGovern report states:

> 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. p. F-20

G1-81.28

The aforementioned figures from the DEIR only provide a range or crude oils that have been processed. This discussion fails to evaluate a potential change above a specific baseline (as opposed to a generalized range). The fact that the refinery crude oil can come from different parts of the world, and that the specific crudes fluctuate, is irrelevant to the fact that in past years it has had a specific baseline average for different crude oil characteristics. The baseline averages of different crude characteristics can now change considerably as compared to this baseline, and still remain within the refinery's capacity. This is due largely to Tesoro's plans to provide a new transportation terminal in Washington, and to build an unprecedented volume of storage tanks that can receive this crude, with an extremely high throughput.

G1-81.28 cont'd.

Response G1-81.28

The comment assumes that the proposed project will change the crude oil blend that can be processed by the Refinery. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Due to the fixed crude oil operating envelope that will exist before and after the proposed project, baseline data regarding the particular crude oils combined to meet that blend with the required properties was not necessary to conduct the impact analysis in the DEIR.

The comment specifically claims that because of the proposed Vancouver Energy Project and the size and throughput of new and the replacement storage tanks in the proposed project, the crude oil blend processed by the Refinery will change and therefore baseline crude oil data is required to evaluate the proposed project's impacts in the DEIR. As explained in Response G1-78.104, the Refinery receives the majority of its crude oil via marine vessels, and all waterborne crude oil deliveries would benefit from the increased offloading efficiency that the new and replacement storage tanks would provide. The claims that the crude oil blend would change do not take into account the fact that the proposed project does not include changes to the Refinery Crude Units or the units immediately downstream of the Crude Units that would need to be modified in order to process a significantly different crude oil blend (see DEIR pages 2-17 through 2-19). Response G1-78.107 provides perspective on one of the primary objectives of the proposed project, including recovering and upgrading distillate range material from FCCU feeds, and explains that the proposed project is not designed to enable a change in the crude oil blend processed by the Refinery. Response G1-78.107 also describes the purpose of the new and replacement storage tanks, which is to allow larger marine vessels to fully unload crude oil deliveries in one dock visit, improving efficiency and reducing marine vessel emissions and costs. Additionally, Master Response 2 clarifies that specific data regarding crude oil blends processed by the Refinery are trade secret, confidential business information. Because the data is trade secret and no modifications are proposed to enable a change in the crude oil blend processed at the Refinery, baseline crude oil data was not relied on or provided to the SCAQMD, and need not be provided.

Comment G1-81.29

► **The report expects the public to accept that crude oil data is confidential, even though imported crude oil is public.** Only domestic crude oil is not required to be reported to the US EIA database. In fact, I could replicate a general crude oil slate for the refinery based on public data, described later, which underscores the fact that this is not confidential information, but the details should be provided by the DEIR to perform a proper analysis of the refinery operations and changes.

It is illogical to claim that somehow because domestic crude is not required to be reported, that it is a different animal than imported crude, or that it's use is fundamentally different confidential business information. In the case of the Bakken formation, parts of it extend into Canada. It would be nonsensical to claim that data for a company receiving crude oil extracted just North of the border is public, but revealing the same crude oil extracted just South of the border would somehow damage protected business information. In fact, Tesoro itself has publicly discussed the origins of its crude oils in the news media, as described later in this report. What is missing, is the necessary, detailed baseline, that is crucial to the DEIR evaluation.

G1-81.29

Response G1-81.29

Master Response 2 addresses trade secret or confidential business information associated with the petroleum refining industry. Although information regarding crude oil imports to various refineries is available from EIA data, that information is not sufficient to determine a refiner's trade secret information such as crude oil blending and processing throughput. Releasing the domestic crude oil processing information would compromise the Refinery's trade secret information (see Response G1-81.36). Because the data is trade secret and no modifications are proposed to enable a change in the crude oil blend processed at the Refinery, baseline crude oil data was not relied on or provided to the SCAQMD, and need not be provided.

Comment G1-81.30

► **It generalizes that the local "mode of transportation" would not change (ship and pipeline crude oil deliveries), but this is irrelevant.** This point refers to the very local, and general description that the refinery will continue to receive crude oil by ship, through pipelines, to the refinery.

> 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. (At p. F-18)

However, potential significant impacts can still occur because the Tesoro Savage Vancouver Energy terminal upstream drastically changes Tesoro's access to Bakken (and some Canadian) crudes. Tesoro has stated it will use this terminal to import large volumes of Bakken crude to its West Coast refineries, and specifically to the LA refinery complex.

G1-81.30

Response G1-81.30

Master Response 8 and Response G1-78.139 describes in detail that the Vancouver Energy Project is not part of the proposed project, is undergoing separate environmental review in the State of Washington, and that the Final EIS for the Vancouver Energy Project, which would address its potential impacts, has not been issued and that project has not been approved. The comment assumes that if approved, the Vancouver Energy Project would change the Refinery's access to Bakken or Canadian crude oils. As described in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing blends of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Response G1-78.107 explains that the proposed project is not designed to enable the Refinery to process a crude oil blend containing a significant amount of Bakken crude oil as implied in the comment. In order to process any significant quantities of Bakken or heavy Canadian crude oil, these crude oils would need to be mixed with other crude oils into a blend, similar to current crude oil blend that is suitable for processing by the Refinery.

Additionally, as explained in Response G1-78.104, the Refinery receives the majority of its crude oil via marine vessel. All water borne crude oil deliveries would benefit from the increased offloading efficiency that the new and replacement storage tanks would provide. Therefore, the proposed project would not facilitate deliveries from the Vancouver Energy Project over any other marine delivered crude oil.

Comment G1-81.31

► **It fails to identify expansions of units that offset the Wilmington FCCU shutdown:** The McGovern report identified the Wilmington FCC shutdown decrease as part of the reason that it assumed there would be a reduction in capacity for sulfur processing at the refinery: G1-81.31

> 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. (at p. F-13)

However, this statement did not account for the increase in capacity of the Carson FCCU, and the expanded hydrotreaters (which are expressly for the purpose of removing sulfur contamination). No baseline was provided in the DEIR to demonstrate the sulfur processing capacity in general, nor the baseline of the mentioned Sulfur Recovery Unit (SRU). It is also not just a question of whether the SRU capacity has changed, it is also a question of whether it has slack within its capacity, which could be debottlenecked to operate at a higher level. It appears that Dr. McGovern did not have access to these baselines, as they were not mentioned, and the DEIR did not provide these to the public. G1-81.31 cont'd.

Response G1-81.31

It should be noted that the quote in the comment from the McGovern Report does not identify the Wilmington Operations FCCU shutdown "as part of the reason that there would be a reduction in capacity for sulfur processing at the refinery." The cited McGovern Report quote states that since Refinery FCCU capacity is decreasing, the amount of heavy, low gravity crude oil that the Refinery can process will not increase as a result of the proposed project.

Master Response 4 presents the Refinery SRP capacities and historic operation to demonstrate that the SRPs operate at or near capacity (see Table G0-2.4-2 in Master Response 4 for capacity and throughput data for the baseline 2012 and 2013 period). The proposed project is expected to maintain or slightly reduce the load on the SRPs as further described below.

While the proposed project includes project elements to increase the hydrotreating capabilities at the Carson Operations LHU and the Wilmington Operations HTU-1, it would reduce overall gas oil hydrotreating. The modifications proposed for Wilmington Operations HTU-4 are not to increase capacity, but to enable HTU-4 to operate in either gas oil or diesel service. The sulfur reduction requirements are less when HTU-4 operates as a diesel hydrotreater (up to 15 percent of the time) than when it treats gas oil. Additionally, as noted in Section 4.1.2.3 of the DEIR, gas oil feed from Wilmington Operations will be consistently supplied to Carson Operations

once the Wilmington Operations FCCU is shut down, enabling the Refinery to discontinue or reduce purchasing gas oil feed from external, third-party sources. The Wilmington Operations will supply gas oil hydrotreated to FCCU feed specifications to the Carson Operations. The gas oil purchased from third-party sources is often unhydrotreated or not hydrotreated sufficiently to meet FCCU feed specifications. By shutting down the Wilmington Operations FCCU and reducing or eliminating purchased gas oil, the amount of gas oil requiring hydrotreating will be reduced, and this will offset the additional hydrotreating capabilities potentially added by the proposed project.

Although the McGovern Report did not address the increased processing expected at the Carson Operations as a result of the proposed project, the DEIR analyzed the increased utilization of the Carson Operations FCCU (Section 4.1.2.3 and Table 4.2-4). It should be noted that the comment refers to increased capacity at the Carson FCCU, which is inaccurate. No modifications will be made to the Carson FCCU and the capacity will not increase, however the average annual feed rate, or utilization, of the unit is expected to increase, as explained in Section 4.1.2.3 of the DEIR.

Comment G1-81.32

There are numerous other problems with this report in terms of its failure to cite the basis of its conclusions (rather, it frequently accepts conclusory DEIR expectations, resulting in circular argument), and its failure to make a conclusion based on a specific baseline, rather than a general range. It also fails to recognize the real-world facts, as published by Tesoro, about its actual plans.

This failure of the McGovern Report, and the DEIR, causes a credibility gap. The DEIR should make efforts to actually explore the crude oil baseline, or it will continue to defy believability. The analysis of the DEIR regarding the crude oil switch is deficient based on its failure to recognize available facts, explore available data, evaluate the crude oil slate, evaluate foreseeable changes and the relationship to crude oil changes to the Project, and to take note of Tesoro's own published corporate plans, as well as contradictions to the DEIR's description. Unfortunately, in this aspect, the DEIR reads more like a public relations document provided by Tesoro. It seems determined to avoid evaluation of the crude oil baseline, rather than taking a neutral, scientific, independent approach. This needs to be corrected.

G1-81.32

Response G1-81.32

The comment makes general conclusory claims criticizing the McGovern Report that are not specific and that are not supported with substantial evidence. Response G1-81.28 addresses the claims in the comment that the proposed project will change the crude oil blend that can be processed by the Refinery. Responses G1-81.22 through G1-81.26 address the corporate statements and other articles regarding Tesoro's business strategies that are unrelated to the proposed project. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery.

Comment G1-81.33

III. Tesoro's crude oil slate can be approximated through publicly available data, but the DEIR should provide a detailed baseline, and is off the mark in assuming no Project-related significant crude slate changes

As described above, the Project actually provides not only for combining two oil refineries, but for changing the crude oil slate. This section evaluates the changes.

A. Refinery design, choice of crude oil slate, and emissions are interrelated

Each oil refinery has common processes and equipment to first separate crude oil components from heavier to lighter, then to crack heavier molecules into lighter liquids for gasoline, diesel, and jet fuel blending, to remove contaminants such as corrosive sulfur that comes in with the crude oil, and other processing. Equipment includes distillation and fractionation towers, reaction vessels using heat, pressure, and catalysts, very large boilers and heaters that burn petroleum fuels and gases to drive the refinery's high heat needs, coking vessels that produce a coal-like product from the heaviest crude oil fractions, sulfur removal and recovery units, alkylation units to produce higher-octane gasoline components, piping and thousands of valves and flanges, plus pumps, compressors, wastewater processing (since refineries use large amounts of water), cooling towers, storage tanks, product loading equipment, and rail connections. Refineries also use flares to burn "waste" gases, pressure relief devices which vent gases when pressure gets too high. Oil refineries are major emissions sources.

G1-81.33

Each is also customized to refine a chosen crude oil "slate" (the particular crude mix), and it is a business choice to obtain the least expensive inputs to transport, store, and refine, to make the most profitable outputs (like gasoline). The crude mix, in combination with the refinery design and operations, results in the particular volumes of gasoline, diesel, jet fuel, petroleum coke, propane, and other products sold. The design, operation and crude slate choices will determine the fractions of gasoline, diesel, jet fuel, petroleum coke, propane, butane, etc., produced. **The company makes a decision about what crude oils to purchase within the range of the refinery design, and all these choices impact emissions and safety.**

- If a refinery uses light and low sulfur crude oil (called "sweet" crude), it does not have to remove as much corrosive and hazardous sulfur from the crude oil, and it can produce more light, profitable products such as gasoline and less heavy, cheap products such as petroleum coke (similar to coal). But light sweet crude oils have historically been expensive.
- If a refinery uses heavy, high sulfur crude oil, these are generally cheaper, but the refiner must have larger capacity in sulfur-removing equipment (such as hydrotreaters or desulfurization units), and a large capacity to crack heavy crude oil fractions into lighter liquid molecules for gasoline blending.

G1-81.33 cont'd.

Response G1-81.33

The comment generally summarizes various refinery processes. The comment also describes crude oil slate and makes a statement that refiners make a business choice to obtain the least expensive inputs to make the most profitable outputs and that these choices impact emissions and safety. Examples are given of processing light low sulfur crude oil versus heavy high sulfur crude oil. This is an over-simplification of the crude oil selection and blending process at the Refinery. As described in Attachment C, the Declaration of Douglas Miller[254], Master Response 4, and Responses G1-78.150, G1-78.170 and G1-78.174, the Refinery uses many criteria and tools to evaluate crude oil blends that are capable of being safely processed by the Refinery. These evaluations include process unit and regulatory limitations in addition to specific

[254] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

limitations for safety considerations. If a crude oil does not meet the parameters established by the Refinery to be added to a particular blend, it will not be processed.

Comment G1-81.34

- In Tesoro's case it has historically refined heavier, higher sulfur crude oil in the Wilmington refinery, and less heavy, less sulfurous crude in the Carson refinery (formerly BP).
- **The crude slate was not, and should have been provided in the DEIR.**

G1-81.34

It is established in oil industry literature that changes in crude oil slate affect refinery design, operations, and products, as acknowledged by the DEIR.[28]

[28] For example, DEIR at pp. 2-14 to 2-18

Response G1-81.34

The DEIR, as referenced by the comment, gives a brief description of the Refinery and further explains that the crude oil purchased by the Refinery is blended to fit the constraints of the refinery operations. The DEIR also clearly states that unless the Refinery undergoes physical modifications to the crude and sulfur processing units, that are not included as part of the proposed project, the crude oil blend cannot change (See pages 2-14 to 2-18 of the DEIR). Due to the fixed crude oil operating envelope that will exist before and after the proposed project, baseline data regarding the particular crude oils combined to meet that blend with the required properties was not necessary to conduct the impact analysis in the DEIR. Master Response 4 and Responses G1-78.94, G1-78.95, G1-78.99, G1-78.100 and G1-78.101 provide additional information on crude oil blending and the inability to change the crude oil blend processed by the Refinery.

Comment G1-81.35

B. Tesoro's crude slate baseline can be pieced together based on publicly available data

Although data on the crude slate "baseline" (a measure of the past) should have been provided in detail in the DEIR in order to identify the change from this baseline, the public can piece together a picture of Tesoro's crude oil slate, and changes due to the Project. In addition to the relationship to the proposed refinery equipment and operations changes, and associated environmental impacts. We can illustrate this through the information below step by step, and the associated impacts become very apparent, but the DEIR should be rewritten to include the full details, baselines, and changes relating to the crude oil slate.

G1-81.35

Response G1-81.35

Master Response 2 clarifies that specific data regarding crude oil blends processed by the Refinery are trade secret, confidential business information. Because the data is trade secret and no modifications are proposed to enable a change in the crude oil blend processed at the Refinery, baseline crude oil data was not relied on or provided to the SCAQMD, and need not be provided.

The comment further states that additional information will be provided in the comments that follow. No response is required under CEQA.

Comment G1-81.36

The public has online access to the U.S. Energy Information Administration (EIA) data on *imported* crude oil from foreign countries used in each oil refinery, with monthly data on the country of origin of the crude, the number of barrels, the sulfur percent, the API gravity, the Port City, and a few other pieces of information. However, the EIA data does not include *domestic sources* of crude oil used by each refinery. It cannot be claimed that somehow crude oil which comes from foreign sources is proprietary, but domestic crude oil use is confidential, and in fact there is general information available about domestic crude oil as well which is published by oil refiners including Tesoro, but it is not available in such an organized way

Oil refiners are required to report data to the US Energy Information Administration (EIA) on crude oil imported into the U.S. I downloaded US EIA 2015 monthly crude oil import data, excerpted Tesoro LA (Carson and Wilmington), which provides country of origin, sulfur content, API gravity, and is reported in thousand barrels each month. I totaled deliveries from each country, and converted to average barrels per day over the year. This data is attached to this report, with my calculations of weighted averages added.[29] The data does not include domestic crude oil use at the refineries, which is not required to be reported the US EIA.

The data shows that in the last year Canadian crude oil was not imported to either the Tesoro Carson or Wilmington refineries, although in previous years, small amounts of Canadian was imported.[30] Imports were from Argentina, Angola, Australia, Belgium, Brazil, Columbia, Ecuador, Equatorial Guinea, India, Iraq, Kuwait, Peru, Russia, Saudi Arabia. It is unknown from this data how much crude oil came from different geographic areas within the U.S., or the quality of this U.S. crude oil (such as percent sulfur, or API gravity). Most of the imports reported for the Tesoro Los Angeles refineries came to the Carson refinery – Wilmington showed almost no imports.

G1-81.36

Table 1: Tesoro Carson crude imports downloaded from US EIA 2015 data & aggregated[31]

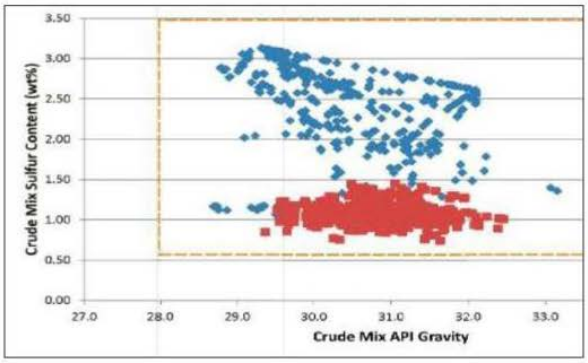
2015 imports	**Volume** (average barrels/day, converted from thousand barrels delivered during one month]	Percent of imported	Weighted Average Sulfur %	Weighted Average API Gravity
Angola	37,403	23.4%	0.43 (Sweet)	29.4 (Moderate)
Iraq	36,367	22.8%	3.16 (Sour)	28.2 (Moderate)
Saudi Arabia	32,066	20.1%	2.00 (Sour)	33.1 (Light)
Brazil	21,493	13.4%	0.36 (Sweet)	30.6 (Light)
Ecuador	17,211	10.8%	1.54 (Sour)	23.0 (Moderate)
Columbia, Equatorial Guinea, Russia, Kuwait, Australia, & Peru	15,304	9.6%	0.32 to 2.62% (Sweet to Sour)	19.4-35.1 (Heavy to Light)
	Total barrels imported		Overall Weighted Average S%	Overall Weighted Average API
	159,844	100%	**1.49** (Sour)	**29.41** (Moderate)

- The 2015 data above shows the Carson refinery imported almost160,000 barrels of crude oil, with weighted average sulfur content at about 1.5%, weighted average API 29 degrees.
- Carson has capacity to process in the range of another 100,000 bbls/day of crude oil, so the 160,000 barrels of foreign imports represents about 60% of the Carson total.
- Tesoro identified which domestic crudes are used in the LA Refinery (Carson and Wilmington together): ***"The refinery processes heavy crude from California's San Joaquin Valley and Los Angeles Basin as well as crudes from the Alaska North Slope,*** *South America, West Africa and other international sources."*[32] Tesoro's SEC report also stated:[33] "Our California refineries run a significant amount of South American heavy crude oil ("Oriente"), **San Joaquin Valley Heavy ("SJVH")** and light crude oil from Iraq ("Basrah"), which continued to be priced at a discount to Brent throughout 2013."
- Carson's domestic crude input portion has historically been Alaska North Slope (ANS).[34]
- That leaves Wilmington with the California San Joaquin & LA Basin crude, since almost no foreign crude oil use was reported for Wilmington in 2015 to the EIA, so most had to be domestic (which the EIA does not report).

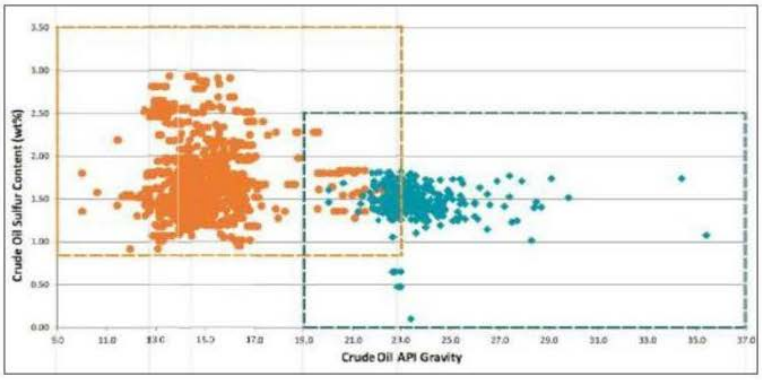
G1-81.36 cont'd.

The DEIR did provide some information on crude oil at the two refineries. For example, the following graphics show sulfur % and API gravity spreads at the refineries (each point represents a different crude oil).

DEIR Figure 2-7 below -- Carson



DEIR Figure 2-6 below -- Wilmington



G1-81.36 cont'd.

Table 2: Predominant Crude Oil sulfur and API gravity range in DEIR figures 2-6 and 2-7

DEIR Figure 2-7 above shows for Carson	**DEIR Figure 2-6 above shows for Wilmington**
Crude Units 1&4 (lower cluster): Mainly ~**0.8-1.4% sulfur,** Crude Unit 2 (upper scatter): Mainly about **1.8-3% sulfur**	Crude Unit (in right box cluster) Mainly about **1.3-1.7% sulfur**
All three Carson Crude Units show API gravity mainly about **29-32°** API	Mainly about **21-25° API**
The DEIR describes *the whole range* for the refinery Sulfur & API range *capability,* including the tail ends outside the main clusters, and not the historical *baseline*	
API gravity range of 28-35° 0.6-3.5 weight % sulfur	19-37° API 0.0-2.5 weight % sulfur

Summarizing the import crude oil US EIA data presented in Table 1, and pulling together additional available information from company statements on domestic crude use for Tesoro Carson (sulfur and API gravity), and the same for Tesoro Wilmington (which has almost no imports, so almost entirely domestic), we can also approximate the overall sulfur and API for the overall Tesoro LA refinery complex. This is within the range of sulfur % and API provided by the DEIR. It also shows that the crude oil sulfur % for the overall refinery can go up or down substantially and still operate within the range of the refinery's capability given by the DEIR. API gravity can also go up or down substantially and still operate within the range of the refinery's capability. The DEIR focuses on the refinery's capability within certain limits, but it does not establish a baseline.

Table 3. Summary of available data to estimate crude oil sulfur and API gravity at the Tesoro Carson & Wilmington Refineries (the Los Angeles Refinery complex)

	Average Barrels per day	Crude Oil	Sulfur	API
Carson Imported Crude	159,844	Mainly from Angola, Iraq, Saudi Arabia, Brazil, Ecuador (Imported Carson crude from EIA 2015 data - see Table 1)	1.49	29.41
Carson Domestic Crude	97,456[35]	Alaska North Slope (ANS) reported by BP Carson	0.9[36]	32.1[37]
Wilmington Domestic	104,500	Reported by Tesoro as California San Joaquin & LA Basin, with approximate Sulfur % & API from DEIR Fig. 2-6	1.5[38]	23[39]
Total LA complex[40]	363,000	Overall refinery weighted average sulfur and API gravity estimation based on above:	**1.33**	**28.19**

G1-81.36 cont'd.

This information should be supplied in the DEIR in detail, providing a more specific baseline for the both the Carson and Wilmington refinery, including the last 5 years' domestic and imported crudes, volumes, geographic origin, transportation method, sulfur content, API gravity, TAN, metal content, other important data such as benzene content, special handling issues due to volatility or waxiness, etc. The DEIR should evaluate impacts of the planned and foreseeable changes in the crude slate as part of the overall Project. Instead the DEIR statements are misleading and conclusory in determining that crude oil slate changes are unrelated to the Project. Tesoro itself has provided overwhelming statements to the contrary in investor statements. Instead of a baseline the DEIR provided a range of sulfur and API gravity. The public can endeavor to dig up the data above, but the DEIR should provide the specific data.

G1-81.36 cont'd.

[29] Tesoro Los Angeles Refinery Monthly Crude Oil Imports in 2015, downloaded by J. May, CBE, 4/15/2016 from the U.S. Energy Information Administration (EIA) monthly petroleum imports by facility, available at: http://www.eia.gov/petroleum/imports/companylevel/ , and also Attachment 14: Tesoro 2015 Crude Oil Imports

[30] My previously cited Tesoro 2014 Negative Declaration comments, p. 19, showed 245 thousand barrels of Canadian crude oil were imported by Tesoro to the Wilmington refinery, for example, in March of 2014. Also as a correction to the label on the table, which identified the units as thousands of "bpd" (barrels per day), this should have been labeled thousands of barrels. The EIA data provides the numbers in units of thousands of barrels delivered in a particular month.

[31] I downloaded monthly reports from the U.S. Energy Information Administration (EIA), available at http://www.eia.gov/petroleum/imports/companylevel/ , for each month in 2015, filtered Tesoro Carson and Wilmington reports, totaled for each country, and calculated weighted average sulfur % & API gravity, Attachments 15 and 16

[32] Los Angeles Refinery Fact Sheet, Tesoro, available at: https://tsocorpsite.files.wordpress.com/2016/04/tesoro-los-angeles-fact-sheet.pdf Attachment 17

[33] http://www.sec.gov/Archives/edgar/data/50104/000005010415000030/ex99112-31x2014tso10xkreca.htm at p. 32, excerpt 2014, Attachment 18

[34] *BP agrees to sell Carson refinery and ARCO retail network in US southwest to Tesoro for $2.5 billion*, BP Website, 12 August 2012, ["The refinery is located on 650 acres in Los Angeles County, near the Long Beach and Los Angeles Harbours. . **It processes crude oil from Alaska's North Slope,** the Middle East, West Africa and other sources. Processing equipment includes the largest fluid catalytic cracker in California, two cokers and distillate hydrocracking."] - http://www.bp.com/en/global/corporate/press/press-releases/bp-agrees-to-sell-carson-refinery-and-arco-retail-network-in-us-southwest-to-tesoro-for-25-billion.html Attachment 19

[35] Total Carson bbls/day from US EIA Jan 1, 2015 Carson total of 257,300[35] so domestic = total minus imported
[36] The North American Crude Boom: How Changing Quality Will Impact Refiners, John R. Auers, Turner, Mason & Company, Platts Crude Marketing Conference, March 1, 2013, Houston, Slide 28, Attachment 20
file:///C:/Users/Julia%20May/Desktop/jan12%20to%20Apr16%20NEW/refineries%20Tesoro/Tesoro%20BP%202016%20integration%20DEIR/background%20info/North_American_Crude_Boom-platt-2013.pdf
[37] *Id.*
[38] Using DEIR Figure 2-6 which shows Wilmington distillation unit mainly in the range from 1.3 to 1.7% sulfur
[39] Again using DEIR Figure 2-6 which shows Wilmington distillation unit mainly in the range from 21-25° API
[40] Using DEIR total number refinery capacity of 363,000 bbls/day (although this is slightly larger than the US EIA total given), DEIR at p. 2-17

Response G1-81.36

While the U.S. EIA database includes information regarding crude oil imports to refineries, that information is not sufficient to determine a refiner's trade secret information such as specific crude oil blends and processing throughput. As described in Master Response 2, there are many areas of trade secret or confidential business information associated with the petroleum refining industry. Releasing crude oil processing details, including domestic crude oil processing information, would compromise the Refinery's trade secret information. The comment assumes that by totaling crude oil deliveries from each country and converting to average barrels per day of the year, the public can glean detailed information on the imported crude oil blends processed by the Refinery. As described in Response G1-81.33, the Refinery uses many tools and criteria to determine crude oil blends to be processed by the Refinery including crude oil assays, blending models, process unit limitations and financial evaluations. At any time, the Refinery has numerous storage tanks in crude oil service (see Response G1-78.126, that clarifies there are 132 storage tanks capable of storing high vapor pressure crude oil in the Refinery). Various crude oils are used in different proportions and at different rates to make the crude oil blends processed by the Refinery. Crude oil received by the Refinery is not processed on an average basis over the year. Therefore, the aggregated data presented in Table 1 of the comment based on imported crude oils, does not represent the crude oil blends processed by the Refinery.

The comment also points out that, based on EIA data, no Canadian crude oil was imported to the Refinery in 2015. Tesoro reports that this is not correct, Canadian crude oil was imported and processed by the Refinery in 2015.

Table 2 of the comment presents average crude oil property data based on the data provided in the DEIR (Figures 2-6 and 2-7). The point of Figures 2-6 and 2-7 of the DEIR is that the properties of the crude oil blend processed by the Refinery may change, but they will fall within the operating envelope, or ranges of crude oil properties, capable of being processed by the Refinery. Average crude oil properties do not represent the variety of crude oil blends that fit within the Refinery's operating envelope.

The comment also assumes sources and types of domestic crude oil based on "[Tesoro] company statements". Based on these assumptions, the comment presents Table 3 as a representation of average Refinery crude oil blend quality, and claims that the crude oil blend sulfur content and API gravity can vary substantially and remain within the operating envelope presented in the DEIR. Responses G1-78.120 and G1-78.121 address the issues raised in the comment and explain that there is limited ability for the Refinery crude oil blend quality to change within the operating envelope (see Section 2.5.4.2 and the graphs on pages 2-21 and 2-22 of the DEIR).

There are data points that show Refinery operation throughout the ranges of the operating envelope. Appendix F of the DEIR pages F-17, F-21, and F-22 address the fact that there is limited ability for the Refinery crude oil blend quality to change within the operation envelope ("parameter creep") and that any minor changes in crude oil blend quality would have insignificant impacts on operation and potential environmental impacts. It should be noted that Tesoro performs analyses, in addition to sulfur content and API gravity, to evaluate crude oils for inclusion in the blend to be processed by the Refinery. Responses G1-78.120 and G1-78.121 also describe in more detail additional analyses performed on individual crude oil blends.

The comment concludes that the DEIR should provide detailed baseline crude oil information and that "the DEIR should evaluate the impacts of planned and foreseeable changes in the crude oil slate as part of the overall Project." As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4 and Response G1-78.94, the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. There are no "planned and foreseeable changes in the crude oil slate" as part of the proposed project. Due to the fixed nature of the crude oil operating envelope that will exist before and after the proposed project, baseline data regarding the crude oils comprising the blend are not necessary to conduct the impact analysis in the DEIR and was not relied upon in the analysis of impacts.

It should be noted that the comment also suggests other crude oil properties, including TAN, metal, benzene, volatility, and wax content require evaluation in the DEIR. Responses to prior comments have addressed all of these properties, and Table 78.94-1 lists crude oil properties and the location of related responses.

Comment G1-81.37

C. Tesoro's business plan emphasizes Bakken crude, but also has ready options for blending Canadian and Bakken to approximate Alaska North Slope yields

Crude oil blending can be used to achieve needed characteristics: *"By blending lower-grade crude oil with higher grade crude oil or natural gas to reach, but not exceed, target specifications, the price valuation of crudes can be increased significantly. Profits are earned if target specifications are reached by blending the minimum amount of high-grade crude oil with low-cost hydrocarbons."*

An oil industry presentation, *The North American Crude Boom: How Changing Quality Will Impact Refiners*,[41] specifically identified a blend of cost-advantaged Bakken and Canadian crude oils as a replacement for Alaska North Slope crude oil (*"Profitable opportunities for light/heavy crude blending have developed")* using Bakken and Canadian crudes (WCS or Western Canadian Select[42]) to approximate Alaska North Slope (ANS) crude oil.

Market Prices, $/B	2011	2012	Jan 2013
ANS (Long Beach)	110.01	111.15	109.98
Bakken (Clearbrook)	98.26	88.90	91.23
WCS(Hardisty)	79.25	72.25	59.19
Estimated Blending Profitability*	$12 to $15/B	$21 to $25/B	$25 to $29/B

*Assuming unit train rail transportation for Bakken and TM P/L transportation for WCS and allowing for estimated quality differential between WCS/Bakken blend and ANS.

G1-81.37

ANS Blending Opportunity

	WCS/Bakken	ANS	Delta
Bakken, %	55%		
WCS, %	45%		
API Gravity	32.1	32.1	0.0
Sulfur, wt%	1.4	0.9	+0.5
TAN, mg/KOH	0.6	0.1	+0.5
LV% Yields			
C4-	3%	4%	-1%
Naphtha	26%	26%	
Kero/Diesel (665 EP)	27%	27%	
Gas Oil (1050 EP)	28%	27%	+1%
Resid (1050+)	16%	16%	

Using such a blend at Tesoro would replace dwindling supplies of lighter, low sulfur Alaska North Slope crude oil used in the range of 100,000 barrels per day (bpd). (The DEIR should provide specific information on actual amounts of domestic crude oils used at the refinery, and all crude characteristics.)

The replacement mix for this amount of ANS crude, using the recommended 55% Bakken and 45% WCS (Western Canada Select) as proposed by Turner, Mason, & Company above, would mean 55,000 bpd of Bakken, and 45,000 bpd of WCS. This would result in yields of C4 hydrocarbons, naphtha, kerosene/diesel fractions, gas oil, and resid[43] that are very similar to the yields produced by Alaska North Slope crude (as listed in the table). API gravity would be the same, sulfur content and TAN (Total Acid Number) would be up 0.5%. This switch is clearly feasible, but there would be significant impacts of this switch. **Tesoro could furthermore replace portions of the California heavy crudes with cheap Canadian crudes as well.**

While the DEIR claims that Tesoro is not doing this, it proposes no permit conditions that would prevent this switch, and it fails to evaluate the environmental impacts that would occur due to this switch.

These examples illustrate that contrary to the DEIR, Tesoro can use this Project to switch its crude oil stock to cheaper North American Bakken and Canadian Tar Sands Crude Oil, by providing tank expansions to accommodate the new crudes, while connecting transport routes through the Tesoro Savage terminal (projected to start in 2017), and also through addition of extensive sulfur contamination removal equipment (hydrodesulfurization and hydrotreaters, discussed below) that can remove higher sulfur content from Canadian crude. The DEIR identifies additional benefits of these activities (such as reducing ship port time), but that does not prevent the project impacts that would occur due to the crude oil switch.

G1-81.37 cont'd.

The DEIR instead described limitations of the refinery that it concluded would prevent such crude oil slate changes, but it failed to evaluate crude mixes that would leave the refinery operating within its design parameters for crude API gravity range. For example, the Bakken /WCS blend would approximate the current ANS API. This would avoid the problems the DEIR identified (such as flooding in the Distillation unit if too much light crude was present for the unit design[44]) or overwhelming the coking units if too heavy a mix was identified, but it would still introduce new impacts.

So even if matching ANS exactly in gravity, the switch would still introduce new impacts not evaluated in the DEIR, due to other crude oil characteristics. For example, explosion hazards would increase from Bakken crude introduction, additional content of toxics such as benzene that werenot investigated in the DEIR discussion would be introduced, and increased introduction of waxy residue which can cause processing difficulties requiring more maintenance. Further, increased sulfur mass from Canadian crudes would increase corrosion hazards and increase acutely hazardous sulfur gases (for example hydrogen sulfide).

There are other Canadian tar sands crudes that can be blended this way – the DEIR should provide an evaluation of the Canadian crudes which have been used at the refinery, and which could be used (unless permit conditions are set prohibiting the use of Canadian tar sands crude oils).

The switch to Bakken and potentially Canadian Crude has major impacts (later described) that must be analyzed, unless permit conditions are set to preclude use of these crudes.

G1-81.37 cont'd.

[41] *The North American Crude Boom: How Changing Quality Will Impact Refiners,* John R. Auers, Turner, Mason & Company, Platts Crude Marketing Conference, March 1, 2013, Houston, file:///C:/Users/Julia%20May/Desktop/jan12%20to%20Apr16%20NEW/refineries%20Tesoro/Tesoro%20BP%202016%20integration%20DEIR/background%20info/North_American_Crude_Boom-platt-2013.pdf

[42] WCS or Western Canadian Select has 3-3.5% Sulfur, 20.5 to 21.5° API density Oil Sands Magazine, Western Canadian Select Explained, Feb. 18, 2016, http://www.oilsandsmagazine.com/western-canada-select-wcs-crude-oil-definition/

[43] Residual oil

[44] See DEIR at p. 2-16

Response G1-81.37

The comment and the original Turner, Mason & Company presentation over-simplify the crude oil blending process. The concept of a blend of 55 percent Bakken and 45 percent Canadian crude oil yielding a blend that is similar to ANS crude oil was presented in a prior comment. Response G1-78.150 explains in detail why such a blend does not mimic ANS and could not be directly substituted. Additional crude oils would need to be added to make a blend that would be suitable for processing at the Refinery. As a result of this necessary blending of crude oils to meet current and continuing Refinery constraints, there will be no additional emissions impacts caused by the proposed project other than those fully described and analyzed in the DEIR.

The comment further claims that that the DEIR did not evaluate all the impacts that would occur if the proposed project includes a change in the crude oil blend processed by the Refinery. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. However, the impacts suggested in the comment for evaluation in the DEIR have been included in other comments and responded to as indicated in Table 81.37-1.

Table 81.37-1

Topics Raised in Comment and Location of Responses

Topic	Response	
	Master Response Number	Specific Cite or Response Number
Storage Impacts were Based on Worst-Case Crude Oil Properties	6	G1-81.39, G1-78.114 and G1-78.157
Blending and Refining Impacts will not Change	4	DEIR Sections 2.5.3 and 2.5.4, G1-81.34, and G1-78.94
Bakken Crude Oil not Classified as Explosive	-	G1-81.57 and G1-78.160
No Impacts from Waxy Deposit in Bakken Crude Oil	-	G1-81.54, G1-81.55, and G1-78.162
Sulfur Content of Canadian Crude Oil Similar to other Crude Oils/Corrosion Issues	-	G1-78.111, G1-78.166, and G1-78.168
Additional TACs, Including Benzene, were Analyzed in the DEIR	-	G1-81.39, G1-78.114 and G1-78.157

Note: - = No Master Response prepared on this topic.

Comment G1-81.38

D. Many Project elements involve expanded sulfur contamination removal

Tesoro is adding a significant amount of sulfur contamination removal equipment as part of the Project. Sulfur contamination comes into the refinery with the crude oil. Higher sulfur crude oil (called "sour" crude) contains more sulfur than low sulfur crude (called "sweet" crude). Sulfur contamination must be removed for multiple reasons. Sulfur compounds are corrosive attack refinery equipment, and can cause thinning of metals until they fail,[45] as in the case of the Chevron Richmond 2012 explosion, where the U.S. Chemical Safety Board found that such sulfidation corrosion and metal thinning had been repeatedly identified by Chevron workers and inspectors, but

G1-81.38

left unrepaired, causing a major fire and burning of the refinery distillation unit.[46] Sulfur compounds can also poison catalysts used for cracking longer chain crude oil components in the refinery, so that catalysts do not perform their function properly. Sulfur compounds must also be limited in the end products coming out of the refinery (gasoline, diesel, and jet fuel). California has long had low-sulfur requirements for fuels necessitating such sulfur removal equipment (see more in the next section). The DEIR also explains the need to remove sulfur (and nitrogen):[47]

> To meet product specifications, impurities in the crude oil, such as sulfur and nitrogen compounds and metals, must be removed. **Hydrotreating units remove sulfur and nitrogen from process streams; sulfur in the form of hydrogen sulfide, and nitrogen in the form of ammonia, which are then converted into elemental sulfur and nitrogen in sulfur recovery units.** Nitrogen, an inert gas, is emitted from the sulfur recovery unit.

While the Tesoro Wilmington and Carson refineries have extensive sulfur removal equipment (such as hydrotreaters), the Project includes the following expanded process units for this purpose, as compiled in the table below, based on the DEIR and Proposed Title V Permit for the Project:

Table 4: Project Modifications that Add Capacity to Remove Sulfur Contaminants[48]

Light Hydrotreating Unit modification A/N 567645	"The Light Hydrotreating Unit will be modified to more effectively remove sulfur from FCCU gasoline, for compliance with federally mandated Tier 3 gasoline sulfur specifications. **The modified Light Hydrotreating Unit will process a higher sulfur feed material derived from existing fractionation equipment.**"
Naphtha Hydrodesulfurization Unit modification A/N 567646	"The Naphtha Hydrodesulfurization Unit will be modified by the installation of new equipment **to allow removal of contaminants from unit feed and sulfur from pentanes**."
Mid Barrel Distillate Treater modification A/N 578248	"The Mid Barrel Unit will be modified to **enable it to desulfurize heavy FCCU naphtha.** Interconnecting piping to/from the Light Hydrotreating Unit and Mid Barrel Distillate Treater will be installed."
New Wet Jet Treater (future permitting) A/N 567619	"A new 50,000 BPD Wet Jet Treater will be installed **to remove mercaptans** and to reduce the Total Acid Number (TAN) of jet fuel." (Mercaptans are sulfur compounds.)

The DEIR and Draft Title V permit documents frequently emphasize the purpose of the additional desulfurization equipment as a compliance project to meet federal "Tier 3" low sulfur fuels Tesoro does sell some fuels out of state, which will be required to meet the new federal low sulfur fuels standards next year, but this is a small fraction of total Tesoro sales, so the large increase in

G1-81.38 cont'd.

desulfurization equipment appears out of proportion with what is needed to comply with federal Tier 3 standards. Tesoro confirmed that out-of-state fuels sales from the LA refinery (to Nevada and Arizona) is a small fraction compared to in-state sales (which already meet California's low-sulfur fuels standards), during a meeting with CBE.[49] The DEIR should identify baselines – the fraction of out-of-state fuels sales compared to in-state sales – and the proportion of added sulfur removal equipment that is for federal compliance and the portion that is not.

Tesoro is also reconfiguring the refinery to shut down the Wilmington FCCU while expanding the Carson FCCU and Carson Hydrocracker processing, and at the same time adding flexibility to switch from gasoline to distillate production. These changes are also being done in concert with some reconfiguring of the sulfur removal processing.

However, the total sulfur removal processing in the refinery should not change drastically unless Tesoro brings in significantly more high-sulfur crude oil. Tesoro does have an opportunity to bring very high sulfur crude oil from Canadian Tar Sands to the LA refinery when the Tesoro Savage Vancouver terminal becomes operational (projected for this fall). While the refinery can already process some higher sulfur crude oil, the average sulfur percent is not close to the extremely high sulfur content of Canadian tar sands crude oil. While most of the crude delivered to the Tesoro Savage Terminal would be lower sulfur Bakken crude, significant volumes of tar sands crude will also be available to Tesoro LA through Tesoro Savage Vancouver.

G1-81.38 cont'd.

For all the above reasons, the DEIR needs to provide a baseline of the existing sulfur recovery capacity, and the overall increase in sulfur removal capacity that the Project will provide. This not only has implications for the specific crude oils brought to the refinery, it also means a large increase in the processing of acutely hazardous hydrogen sulfide and other hazardous sulfur compounds in the refinery. It should not be assumed that Tesoro's added desulfurization equipment is only is for compliance purposes.

[45] *[*"***Sulfur Compounds.*** *Sulfur may be present in crude oil as hydrogen sulfide (H_2S), as compounds (e.g. mercaptans, sulfides, disulfides, thiophenes, etc.) or as elemental sulfur. Each crude oil has different amounts and types of sulfur compounds, but as a rule the proportion, stability, and complexity of the compounds are greater in heavier crude-oil fractions.* ***Hydrogen sulfide is a primary contributor to corrosion in refinery processing units. Other corrosive substances are elemental sulfur and mercaptans. Moreover, the corrosive sulfur compounds have an obnoxious odor.*** *Pyrophoric iron sulfide results from the corrosive action of sulfur compounds on the iron and steel used in refinery process equipment, piping, and tanks.* ***The combustion of petroleum products containing sulfur compounds produces undesirables such as sulfuric acid and sulfur dioxide. Catalytic hydrotreating processes such as hydrodesulfurization remove sulfur compounds from refinery product streams.****"]* emphasis added, available at:

[46] U.S. Chemical Safety Board, Final Investigation Report, Report No. 2012-03-I-CA, Chevron Richmond Refinery Pipe Rupture and Fire, January 2015, available at http://www.csb.gov/chevron-refinery-fire/, for example at p. 5.

[47] DEIR at p. 2-12

[48] Draft Title V Permit, pp. 26-27 AQMD engineering evaluation (111th to 112th pages of the pdf).

[49] 6/1/2016 meeting of CBE and Tesoro by telephone and webex presentation of Tesoro LARIC project.

Response G1-81.38

The comment notes that the proposed project includes modifications to sulfur removal equipment at the Refinery, notes that sulfur enters the Refinery with the crude oil and refers to the Chevron Richmond 2012 fire that was caused by sulfidic corrosion. Response G1-78.111 provides a detailed description of the root cause of the Chevron Richmond incident and measures Tesoro has put in place to ensure the type of failure involved in the Chevron Richmond incident will not occur at the Refinery.

The comment also summarizes in Table 4, elements of the proposed project that involve removal of sulfur contaminants from liquid hydrocarbon streams, and concludes that more Refinery modifications appear to be involved than are required to comply with federal Tier 3 gasoline standards and therefore the modifications are to enable the Refinery to process higher sulfur

crude oil. It is important to understand that there are numerous hydrotreating units in the Refinery to remove sulfur from intermediate process streams as part of the refining process. However, the sulfur removed in the hydrotreating units must be recovered in the SRPs in order to be converted to elemental sulfur, a useful by-product. Therefore, the SRP is the limiting factor on the amount of sulfur that can be removed during the refining process. Since no modifications to the SRPs are included in the proposed project, the actual sulfur removal capacity of the Refinery will not change as a result of the proposed project. As confirmed by Dr. McGovern in Appendix F of the DEIR (see page F-12), the proposed project is not designed to, and the Refinery cannot accommodate, a change in the range of sulfur allowed in the crude oil blend processed by the Refinery.

Further, the proposed project will facilitate additional gasoline blendstock hydrotreating in order to decrease gasoline sulfur content, which will increase load to the SRPs. However, this increased load to the SRPs will be offset by decreased hydrotreating of purchased untreated raw gas oil. Specifically, as part of the proposed project, gasoline blendstock will be treated from current concentrations (20-30 ppm or 0.002-0.003 percent) down to U.S. EPA Tier 3 levels (averaging 10 ppm or 0.001 percent), thus increasing load to the SRPs. However, this increase in sulfur load will be offset by replacing the current purchased untreated raw gas-oil feed to the Carson FCCU (containing approximately 2 percent sulfur) with treated gas-oil feed from Wilmington (containing approximately 0.05 percent sulfur) which will be available after the proposed project is implemented and the Wilmington FCCU is shutdown.

The Light Hydrotreating Unit (LHU) and the Naphtha Hydrodesulfurization Unit (NHDS) modifications are proposed project elements directly related to U.S. EPA Tier 3 gasoline compliance. Modifications to both of these process units are proposed to enable hydrotreating of gasoline blending process components that are currently not treated (see DEIR Section 2.7.2.5). These higher sulfur gasoline blending components are currently used without treatment for blending gasoline for sale out of State, primarily in Arizona and Nevada.

Additionally, the Carson Operations Mid Barrel Distillate Treater modifications are specifically proposed to enable the mid Barrel Distillate Treater to process naphtha in addition to distillate (see DEIR Section 2.7.2.9), to ensure that the Refinery has redundancy in its ability to meet Tier 3 gasoline standards when the LHU is undergoing a turnaround in the future.

Of the proposed project elements listed in Table 4 of the comment, the Wet Jet Treater is not related to Tier 3 gasoline compliance. The Wet Jet Treater will be installed to meet several proposed project objectives: it will increase Refinery processing efficiency as indicated in Section 2.2 of the DEIR by enabling direct treatment of distillates recovered from FCCU feeds, instead of requiring additional downstream processing of the combined distillate and gasoil stream in the FCCU. Treating distillates recovered from FCCU feeds is another proposed project objective (see Section 2.2 of the DEIR), which in turn enables the shutdown of the Wilmington Operations FCCU.

The comment further claims without substantial evidence, that since the Refinery's gasoline sales in Arizona and Nevada are not as significant as its California sales, the Refinery's plans for sulfur removal capacity may be associated with a change in the sulfur content of the crude oil

blend processed by the Refinery rather than for federal Tier 3 gasoline compliance. The Refinery currently meets the Tier 3 gasoline sulfur content for most of the gasoline produced. However, as of January 1, 2017, Tesoro's entire gasoline pool production average sulfur content was required to meet the U.S. EPA Tier 3 requirement of 10 ppm. Therefore, modifications to the gasoline blending stream (naphtha and other light ends) hydrotreating units are planned to meet this compliance requirement for additional sulfur removal (see Section 2.7.2 of the DEIR).

The proposed hydrotreater project modifications are focused on the Tier 3 gasoline specification that is changing. While there are project elements that will increase sulfur removal from distillates and gasoline blending components, the volume of gas oil requiring sulfur removal will be reduced. As explained in Response G1-81.31, the reduced gas oil hydrotreating offsets the additional distillate and gasoline blend stock hydrotreating. The sulfur removal capacity of the Refinery is limited by the capacity of the SRPs, which are downstream of the hydrotreaters. Master Response 4 and Response G1-81.31 address the SRP capacity and the fact that the Refinery operates at or near the SRP capacity.

The modifications and impacts associated the process units identified in comment Table 4, the LHU, the NHDS, the Mid Barrel Distillate Treater and the Wet Jet Treater, have been thoroughly described in Section 2.7.2 and evaluated in the DEIR (see Chapter 4). As explained in Master Response 5, SCAQMD imposes permit limits on process variables that directly limit emissions to levels allowed under applicable rules and regulations. Throughput and production levels do not necessarily directly impact emissions from process units. Therefore, process unit throughput and production data were not relied on to evaluate the impacts of the proposed project. Also, as described in Master Response 2, Tesoro's fuel production data are trade secret, confidential information. Therefore, baseline fuel production data need not be provided.

The comment makes inaccurate statements regarding how the Refinery will be reconfigured to enable the shutdown of the Wilmington FCCU. As described in Section 2.2 of the DEIR, the specific modifications that enable the shutdown of the Wilmington FCCU include recovery and treatment of distillates from FCCU feeds, thereby reducing the remaining FCCU (gas oil) feed that will be processed by the Carson FCCU, and adding flexibility for distillate production. The Carson Operations FCCU will not be expanded. The 10 to 15 percent increases in Hydrocracker capacities at Carson and Wilmington Operations are required to treat the distillates recovered from the FCCU feeds.

The comment claims that the Refinery will bring in high sulfur Canadian crude oil when the Vancouver Energy Project is complete. Master Response 8 and Response and G1-78.139 explain in detail that the Vancouver Energy Project is unrelated to the proposed project, is under separate review in the State of Washington, and is not yet approved. The comment also refers to the high sulfur content of Canadian crude oil compared to the average sulfur content processed by the Refinery and speculates that hazards related to sulfurous compounds will increase. The Refinery has processed heavy Canadian crude oil in its crude oil blend over the last five years. Because of Refinery constraints described in the DEIR (Section 2.5.4.1), including sulfur content and API gravity, the amount of heavy Canadian crude oil that can be added to a Refinery crude oil blend is limited. The proposed project will not change the crude oil blend that can be

processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

Comment G1-81.39

E. Tank expansion is extraordinary, adding 3.4 million barrels' volume of crude oil storage, and allowing about 420,000 barrels/day of increased throughput, with additional impacts not explored in the DEIR

Storage tanks are essential for terminal, transportation, and refining operations, as Tesoro has stated.[50] But contrary to the DEIR, the extraordinary tank expansions are not solely for faster ship offloading. They include not only 3.4 million bbls of new storage, but also increased *throughput* through new tanks greater than 153 million bbl/year (or 419,000 bbls/day average), when only including the six largest new tanks. Throughput is a measurement of how fast the material through the tanks is turned over (or emptied and replaced). It is a measure of volume moved per unit of time (such as barrels moved per day or per year in this case). By comparison, the existing Tesoro LA refinery complex can process crude oil of at least 363,000 bbls/day, and in addition already has storage to accommodate its current daily crude throughput needs, so the new tanks would add new throughput capability greater than the entire existing refinery currently processes. G1-81.39

Where would an entire refinery's worth of new crude oil throughput go? It does not simply sit in new tanks. The DEIR should provide a detailed analysis, including exports to Tesoro facilities (e.g. Tesoro Logistics), to third parties, and others. Yet the DEIR states: *"There is no change proposed to crude oil throughput at the Carson Operations"* and *"As discussed in Chapter 2, no changes to the Crude Units are being made that would affect the crude oil throughput of the Wilmington Operations."*[51] These conclusory statements fail to account for the throughput increases in the large tanks that were modeled as allowable in the DEIR and cited below. For clarity - the throughput for the whole refinery is the actual refining of the crude oil, first through separation in the distillation units, then cracking, etc., downstream, until it is made into products such as gasoline, diesel, etc. This is a separate issue from the tank's crude oil throughput – which is the simple loading of crude into and then draining crude from the new storage tanks. But the DEIR still does not explain the ultimate fate of the large flow of crude oil through these new tanks.

This is important because the downstream end use of this crude will have significant impacts, whether it is sold to other refineries in the region, or exported out of the country, or used as a throughput increase in the Tesoro LA refinery. If instead the crude just sits in the tank and does not get used quickly, then the throughput identified in the EPA TANKS model would not be as high as it is modeled. The DEIR does not identify whether the EPA TANKS turnover rate would also be used as permit limits when a permit is developed. The AQMD does not yet have a published draft permit for this part of the Project, so we do not know whether the throughput (turnover rate) could go even higher. Further, the DEIR does not provide the throughput for the *sting* crude oil storage tanks, which already have the ability to supply the refinery. G1-81.39 cont'd.

The DEIR also does not provide the total volume for the existing crude oil storage at the Carson refinery (just the Wilmington side, at about 1.7 million bbls).[52] CBE asked Tesoro representatives to provide this information. Tesoro representatives responded that the Carson portion of the refinery has an existing capacity of 2.25 million barrels (for tanks receiving crude from ships).[53] (This does not fully answer whether there are additional crude oil storage tanks *not* received by ship, which should also be disclosed by the DEIR.) Thus, according to the DEIR and numbers provided by Tesoro, the total crude storage capacity is about 4 million bbls for the Wilmington and Carson refineries, and would increase to about 7.4 million bbls (about 85% increase):

Table 5: Proposed Storage Tank Expansions are Extensive[54]

Tank ID	Permit Capacity (Bbls)	New Throughput Capacity from DEIR	Service
	NEW	153 million bbls/yr = ~419,000 bbls/day	
CCT#1(C)	500,000	Each tank was modeled in DEIR at 25.5 million bbls/yr crude throughput, totaling 153 million bbls/yr added throughput for all 6.[55]	Crude Oil
CCT#2(C)	500,000		Crude Oil
CCT#3(C)	500,000		Crude Oil
CCT#4(C)	500,000		Crude Oil
CCT#5(C)	500,000		Crude Oil
CCT#6(C)	500,000		Crude Oil
	REPLACED	Unknown total	
300035(W)	300,000 new	Each 300,000 bbl tank modeled at 18,000,000 bbls/year throughput.[56]	Crude Oil
300036(W)	300,000 new		Crude Oil
80035(W)	80,000* removed	Throughput on these smaller tanks would go away; DEIR does not provide turnover rate.	Crude Oil
80036(W)	80,000* removed		Crude Oil
	MODIFIED	Unknown total	
80038(W)	80,000	Increase throughput, add Vapor Recovery	Petroleum Distillates, adds Light Gas Oils
80060(W)	76,300	Increase throughput, convert to Intern. Float.	Crude Oil
80067(W)	75,000	"	Crude Oil
80079(W)	80,000	Increase throughput	Crude Oil
14(C)	360,000	Increased utilization – App B-3, p B-3-8	Gas Oil
31(C)	78,700	"	Naphtha
62(C)	100,060	"	Naphtha
63(C)	100,060	"	Naphtha
64(C)	100,060	"	Alkylate
502(C) Heated	1,500,000	"	Gas Oil
959(C)	164,000	"	Gas Oil
80044 (W)	79,847	"	Gasoline
80074 (W)		"	Out of Service, to Diesel
80211 (W)		"	Naphtha
80215 (W)		"	Naphtha
80217 (W)		"	Naphtha

G1-81.39 cont'd.

Of note in the table above is:

- **The sheer volume of capacity and throughput** – 8 new tanks, 16 with increased "utilization" and a major increase in throughput (over 153 million bbls/year increased throughput just from the 6 largest new tanks), with a volume increase of 3.4 million bbls.
- **This overall throughput increase means Tesoro will not only be allowed to offload faster from ships simply for storage, but also to send crude oil *out* of these storage tanks faster,** to use or to sell, since the product must go somewhere if removed from the tanks. (The same would be true for materials other than crude oil stored in the Project tanks).
- **This volume and throughput increase opens up a large amount of flexibility for other refinery tanks,** so all the refinery tanks should be considered a part of the Project.

G1-81.39 cont'd.

[50] "Terminaling, Transportation, and Storage" will "Consolidate Tesoro volumes in Southern California distribution system" Tesoro presentation, Jan 2014 Deutsche Bank Energy Conference, January 9, 2014, (Slide 24), Attachment 21

[51] DEIR at pp. 4-26 & 4-28

[52] DEIR at p 2-23, *["The Wilmington Operations currently utilize 20 storage tanks to store crude oil and other heavy petroleum liquids (18 have a capacity of 80,000 bbl and two have a capacity of 125,000 bbl). "]*
18 x 80,000 + 2 x 125,000 = 1,690,000 bbls (about 1.7 million bbls)

[53] 6/1/2016 meeting of CBE and Tesoro by telephone and webex presentation of Tesoro LARIC project.

[54] Information from DEIR Append B-3, Tables 1 & 2

[55] From DEIR App B-3, p. B-3-121, TANKS modeling inputs (21,000,000 gal tank, divided by 42 gals/bbl = 500,000 bbls). Turnovers listed at 51.0 (annual): 51 x 500,000 bbls = 25.5 million bbls/year throughput for each.

[56] As above, 60 turnovers per year gives 300,000 x 60 = 18,000,000 bbls/year throughput each new tank. *(As above, from App B-3, p. B-3-182*

Response G1-81.39

The comment claims that the new and replacement crude oil storage tanks will be used for other purposes, besides more efficient marine vessel offloading, due to the size and throughput of the proposed tanks.

First, the comment appears to confuse storage tank throughputs with Refinery processing throughput. The comment questions the large throughput of the tanks, citing that the throughput of the new Carson Crude Terminal tanks alone exceeds the capacity of the Refinery. It should be noted that there are many reasons for refineries to specify large storage tank throughput. The storage tank throughputs analyzed in the DEIR are the maximum throughputs that would be allowed by the Title V permits that would be issued for the new and replacement storage tanks. Any foreseeable operating scenario must be included in the storage tank throughput analyzed, such as the potential increased use of storage tanks due to maintenance activities on other storage tanks in the same service, in addition to the maximum operating scenario. The tank throughputs that are evaluated in the DEIR are conservative (large) estimates of throughput that may be needed to offload the largest marine vessels (VLCCs) that dock at Marine Terminal 1. As indicated in Section 2.7.2.11 of the DEIR, VLCCs have a capacity of up to 2.0 million bbl. In order to achieve the proposed project goal of efficient crude oil offloading, the throughputs for tanks receiving crude oil cargos from VLCCs must be large enough to accommodate the efficient unloading of VLCCs within one dock trip, to meet the proposed project goals. It is important to note that the volume of available crude oil storage and throughput capacity has no bearing on Refinery crude oil processing capacity (see Master Response 6 and Response G1-78.180).

As part of its Title V permitting program, the SCAQMD imposes throughput limitations on tanks that store petroleum products. The permit holder is required to maintain throughputs below the permitted level in order to minimize storage tank working emissions and stay within the rates evaluated in the permit applications. Therefore, the throughputs analyzed in the DEIR must conservatively evaluate the maximum throughput, or transfer rate, that is required to quickly offload VLCCs plus a “compliance margin” to ensure that the actual unloading rate always remains below the allowable level. This does not mean that the individual tanks will receive crude oil transfers from marine vessels every day at this rate. However, in order to accommodate VLCC offloading at maximum rates, the tanks must be permitted to receive crude oil at these maximum rates.

The DEIR evaluates the maximum expected emissions that would be associated with operation of the new and replacement storage tanks by evaluating a conservatively large throughput and worst-case properties of the materials to be stored in the tanks. The worst-case hybrid analysis of crude oil properties is described in more detail in Response G1-78.157. When permitting equipment that has undergone CEQA review, permits issued by the SCAQMD must be consistent with the CEQA document (i.e., the permitted post-project potential emissions must be equal to or less than the post-project emissions evaluated in the CEQA document). The basis of the storage tank emission calculations in the DEIR includes a crude oil vapor pressure approaching the maximum vapor pressure allowable by SCAQMD Rule 463 (TVP limit of 11 psia) in order to estimate VOCs and TACs for the new and replacement storage tanks and fugitive emissions (see for example Appendix B page B-3-122 of the DEIR that lists RVP=10.5

(TVP limit of 11 psia) under "Basis for Vapor Pressure Calculations"). Storage tank emissions permitted pursuant to the proposed project FEIR will be consistent with FEIR post-project emissions.

The comment suggests that a statement should be included in the DEIR specifying that the tank permits must be issued based on the throughputs analyzed in the DEIR. Without such a statement, the comment claims that there is no assurance that the throughput rates analyzed in the DEIR will be imposed on the permits that may be issued at a later date for the new crude oil storage tanks. The DEIR is required to fully analyze the proposed project in order for the proposed project permits to be issued. Permit applications have not been submitted for the new crude oil storage tanks. However, when the applications are submitted, the permitted throughputs, properties of materials stored in the tanks, and the evaluated emission impacts must be consistent (result in the same or less impacts) with the DEIR, or the SCAQMD will consider whether, and to what extent, the DEIR would need to be revised.

The comment also suggests that volume of crude oil storage capacity in the proposed project is significant in comparison to the existing crude oil storage capacity at the Refinery and the Carson Crude Terminal. Response G1-78.126 provides a detailed description of the existing tanks at the Refinery and the Carson Crude Terminal that are capable of storing high TVP crude oil based on the Refinery's current Title V permit. Specifically, there are 60 storage tanks at Carson Operations capable of storing crude oil with vapor pressures from 7 to 11 psi. At the Carson Crude Terminal, all 5 existing storage tanks are capable of storing crude oil with TVP up to 11 psi. There are 66 storage tanks at Wilmington Operations capable of storing crude oil with TVP from 9.15 to 11 psia TVP. The total existing crude oil storage capacity is 11.0 million barrels. Upon completion of the proposed project, the crude oil storage capacity will be 14.4 million barrels.

The objective of the proposed additional storage capacity is to more efficiently offload marine vessels, which will reduce demurrage (costs to Tesoro for ships waiting to unload) and reduce vessel emissions (see page 2-5 and pages 4-26 through 4-29 of the DEIR). Over the years, since the Refinery and associated storage tanks were built, marine vessels transporting crude oil have increased in size.[255] While Tesoro's marine terminals already receive the largest marine vessels they are capable of receiving, the larger new and replacement crude oil storage tanks would enable more efficient offloading of marine vessels. The proposed increased crude oil storage volume and throughput is designed to enable efficient offloading of marine vessels up to VLCCs. Other Refinery crude oil storage tanks that are not impacted by the proposed project do not require evaluation in the DEIR.

[255] See http://www.globalsecurity.org/military/systems/ship/tanker-history.htm. See also the American Petroleum Institute website, Adventures in Energy, "2002-In the latter half of the 20th Century, advances in exploration and recovery technology opened up new supplies of oil and natural gas all around the world. To make long-distance transportation more cost-effective, tanker manufacturers developed "very large capacity carriers," or VLCCs, that can carry more than 1,400,000 barrels of crude oil." http://adventuresinenergy.org/Oil-Tankers/index.html.

As discussed in Response G1-81.52, the proposed project is not intended to enable the sale of crude oil stored at the Refinery to third parties and there is no evidence suggesting otherwise. The proposed project does not include modifications to enable the export of crude oil.

Comment G1-81.40

- **These permitted implications were not evaluated in the DEIR.** G1-81.40

Response G1-81.40

As explained in detail in Response G1-81.39, the DEIR evaluated the maximum expected emissions that would be associated with operation of the new and replacement storage tanks by evaluating a conservatively large throughput and worst-case properties of the materials to be stored in the tanks. Other potential impacts associated with the new and replacement storage tanks were thoroughly evaluated in Sections 4.2 through 4.7 of the FEIR.

Comment G1-81.41

The DEIR should provide evaluation regarding how these new and expanded tanks allow the accommodation of new crude oils including Bakken, Canadian Tar Sands, and others. For Bakken crudes this would include but not be limited to higher tank vapor pressure limits, special handling and solvent additions for waxy deposits, and adding controls for higher volatility, including higher benzene[57] and other toxics. For heavy crudes such as Canadian tar sands this would include accommodations such as additional heating, and additional mixing, as well as added solvents.

The original 2014 Negative Declaration (ND) did identify a high vapor pressure limit for the two replaced tanks. High vapor pressure indicates Bakken crude accommodation. These same tanks are part of the 2016 project (300035 and 300036) listed with the same new characteristics, but the ND also provided the vapor pressure information (True Vapor Pressure (TVP) at 11 psi (lbs/square inch)),[58] consistent with Bakken crude oil. The DEIR should identify the vapor pressure of this and other Project tanks.

G1-81.41

[57] Dr. Phyllis J. Fox, July 1, 2013, *Comments on Initial Study/Mitigated Negative Declaration (IS/MND) for the Valero Crude by Rail Project Benicia, California Use Permit Application*, ["**The pollutants in the diluent blended with these DilBit crudes and in the light sweet shale crudes include significant amounts of hazardous air pollutants, such as benzene, a potent carcinogen.**"] at p. 1, with additional methodology throught, for evaluating the benzene content of Bakken crude, Canadian crude diluents, and other crude oils, available at: http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F93312159 32%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf

[58] 2014 ND at p. 1-13

Response G1-81.41

As explained in detail in Response G1-78.157, the DEIR evaluated impacts of the new and replacement storage tanks of the proposed project based on the worst-case properties of crude oils currently and potentially processed at the Refinery, including Bakken and Canadian crude oil. This included a worst-case hybrid analysis of the toxics content of these crude oils, including BTEX. For the potential issues raised in the comment, see Response G1-78.162 that addresses the fact that waxy deposits are not experienced with Bakken crude oil. As described in Response G1-78.160, the Refinery only accepts pipeline quality crude oils. This means that any heavy Canadian crude oils that are received arrive as dilbit crude oil that does not require heating, mixing, or solvent addition as suggested in the comment.

As described in Response G1-81.39, the new and replacement crude oil storage tanks were evaluated in the DEIR based on a crude oil vapor pressure approaching the allowable by SCAQMD Rule 463 (TVP limit of 11 psia).

Comment G1-81.42

The DEIR should have included a baseline identification of the specific crude oils that currently are, and can be, stored in existing tankage, including baselines for specific crude oils (geographic origin, API, sulfur %, benzene %, volume, metal content, TAN, etc.), and the potential for changes in crude oil given the new tanks. G1-81.42

Response G1-81.42

As described in Responses G1-81.39 and G1-78.157, the new and replacement crude oil storage tanks were evaluated in the DEIR based on a crude oil vapor pressure approaching the allowable by SCAQMD Rule 463 (TVP limit of 11 psia). The evaluation of impacts associated with the new and replacement storage tanks was based on the worst-case properties (including TACs) of crude oils currently and potentially processed at the Refinery, including Bakken and Canadian crude oil. The impact evaluation assumed no crude oil operations for baseline of the proposed new and replacement storage tanks. Therefore, the baseline information suggested by the comment was not used and is not required for the DEIR evaluation. Master Response 2 addresses the fact that the requested information is trade secret, confidential business information and further, the DEIR did not rely on any of this information in the required analysis pursuant to CEQA.

Comment G1-81.43

The Project has the potential for significant additional air emissions from tanks

The DEIR Appendix B, Operational Emissions Calculations, identified significant emissions increases from these tanks due to the Project, even with additional controls added (such as vapor recovery or converting to floating roof tank), for example at p. B-3-45.

However, the DEIR did not discuss tank emissions to the air from tank cleaning and degassing (nor from pipeline cleaning and degassing), which need specific evaluation, especially due to the large increase in volume and throughput. The AQMD found in its Rule 1149 Final Environmental Assessment: for Storage Tank and Pipeline Cleaning and Degassing, that generalized estimations of air emissions due to these activities underestimated emissions, and wrote new requirements. However, the regulation did not cut emissions to zero, it aimed to reduce them.[59] The DEIR should add an evaluation of remaining emissions from tank cleaning and degassing.

The Environmental Assessment concluded that there is a wide variation in emissions from these activities at individual tanks, dependent on specific conditions:

> Closer examination of individual tank logs reveals a wide variation in the actual emissions degassed from the tank. Some tanks have emissions much lower than expected suggesting a tank relatively free of sludge and product residual that was full to begin with and drained quickly. Others have emissions greater than expected probably because there was a larger vapor space that had time to reach equilibrium and/or significant amounts of sludge and product residual that continued to evaporate while the tank was being degassed. Theoretically, 2.3 air exchanges should reduce emission by 90 percent but the logs indicate an actual reduction rate of only 37 percent. (p. 1-11)

G1-81.43

It found:

> There may also be some unquantifiable loss when the contents of the tank are being pumped out of the tank. Vapor may be inadvertently removed if some part of the vacuum hose is above the liquid level.
>
> **Additionally, the degassing logs show that sludge and product residual significantly contribute to the emissions emanating from the storage tanks.** A tank with partial saturation should be able to degas in a shorter time period than a completely saturated tank. However, the logs indicate that degassing actually takes a much longer time. On average, it takes two to three times longer because product residual and sludge continue to release vapors into the tank being degassed. (at p. 1-11)

Since there are many new tanks, and a large increase in throughput, it is not surprising that the DEIR identified additional tank sludge due to the Project:

> Periodically, for maintenance, storage tanks are currently emptied and cleaned, resulting in a sludge that generally requires treatment to recover useful product (oil), etc., and disposal (e.g., disposal at a hazardous waste or nonhazardous waste landfill, depending on the concentration of various constituents). The proposed project includes the replacement of existing Tanks 80035 and 80036 with larger new Tanks 300035 and 300036 and the construction of six new crude oil storage tanks. **The proposed project could generate additional amounts of sludge wastes associated with periodic tank cleaning operations.** The daily volume of waste generated during the periodic cleaning of the new storage tanks is expected to be about the same as current operations because no change in the method for tank cleaning is proposed and no more than one storage tank would be cleaned at any time. It takes several days to several weeks to clean storage tanks, depending on the size and the material stored in the tanks. The sludge is expected to remain on-site and will be used as feedstock to the DCU (i.e., recycled on-site); therefore, **no increase in waste disposal** would be expected from operation of the new and modified storage tanks. (DEIR at p. 4-88)

G1-81.43 cont'd.

However, the DEIR only evaluated the additional tank sludge as a generator of hazardous waste, not for potential increased air emissions, despite the Rule 1149 EA's finding "Additional hydrocarbon vapors are released from the sludge and residue while the tank is degassed". (p. 1-10)

[59] SCAQMD, Final Environmental Assessment: Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing, April 2008, *["The proposed amended rule amendments would instead require a vapor concentration of 5,000 parts per million by volume (ppmv), measured as methane, to be met for at least one hour before allowing the vapors to be vented to atmosphere. This proposed standard will better capture emissions from sludge and product residual remaining in the tanks. Liquid balancing or any other technology that achieves the proposed standard will be allowed."]* Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2008/final-environmental-assessment-for-proposed-amended-rule-1149.pdf?sfvrsn=4

Response G1-81.43

Response G1-78.217 (Roof Landing Losses Section) addresses emissions from storage tank degassing and cleaning. SCAQMD's Rule 1149 requires control of emissions (degassing) when storage tanks and pipelines connected to the Refinery are emptied and cleaned (including periods of sludge removal from storage tanks). Notably, use of a control device during periods of storage tank roof landings maintain emissions at or below "normal" daily operating conditions as evaluated by the U.S. EPA TANKS program.[256] Therefore, storage tank emissions presented in the DEIR are evaluated using the highest or peak operating day emissions.

The comment cites several statements from the Environmental Assessment (EA) that was performed prior to adoption of SCAQMD Rule 1149 and concludes that the DEIR did not evaluate potential emissions from the release of vapors from sludge while the storage tank is degassed. The statements from the EA represent conditions and emissions before implementation of SCAQMD Rule 1149, and those storage tank degassing emissions have since been controlled to maintain emissions at or below "normal" daily operating conditions as indicated in Response G1-78.217.

Emissions from pipeline cleaning and degassing are also controlled. Pipelines are normally only opened for maintenance activities. Pipelines connected to the Refinery are regulated by SCAQMD Rule 1149 and require degassing to a control device prior to opening. For personnel safety and environmental reasons, internal Refinery pipelines are typically de-pressured and flushed with low VOC materials prior to opening for maintenance.

Comment G1-81.44

The DEIR also did not provide an evaluation of the increased VOC, TAC (Toxic Air Contaminant), and GHG emissions which could occur due to introduction of crude oil with higher vapor pressure compared to existing crude oils at the refinery, such as Bakken crude.] G1-81.44

Response G1-81.44

As described in Response G1-81.39, the new and replacement crude oil storage tanks were evaluated in the DEIR, and VOC and TAC emission estimates were based on a crude oil vapor pressure approaching the maximum allowable by SCAQMD Rule 463 (TVP limit of 11 psia).

[256] The calculation is based on the following equations: VOC_{unc} = MW P V / R / (T + 460) S/100 (1 + SF/100) and VOC = VOCunc (1 - Eff/100).

These emissions estimates are higher when TVP is high. There are no GHG emissions from refinery storage tanks. GHG emissions from refineries are produced from combustion.

Comment G1-81.45

Furthermore, the previously cited Fox report on the 2014 Negative Declaration identified significant additional tank emissions not included in the DEIR modeling, including roof landing emissions that should be added to the DEIR evaluation. (at pp. 37-40)

G1-81.45

Response G1-81.45

Response G1-78.217 (Roof Landing Losses Section) addresses emissions from storage tank roof landing losses. The DEIR correctly evaluated the potential emissions from the new and replacement storage tanks.

Comment G1-81.46

Tank size was listed differently in the modeling compared to other project descriptions

As shown in the table below, several tanks were modeled using lower than nominal tank capacity, which could underestimate emissions in the EPA TANKS modeling.[60]

Table 6: Several tanks with higher permitted capacity were modeled for air pollution emissions at lower capacity

Tank ID	Nominal Capacity (Bbls)	
14(C)	360,000*	Modeled at: 346,916 bbls*
31(C)	78,700*	Modeled at 76,596 bbls*
62(C)	100,060*	Modeled at 99,255 bbls*
63(C)	100,060*	Modeled at 99,255 bbls*
64(C)	100,060*	Modeled at 97,796 bbls*
502(C) Heated	1,500,000*	Modeled at 1,211,117 bbls*
959(C)	164,000*	Modeled at 157,371 bbls*

***Tank modeling at lower volumes than nominal permit volume**

G1-81.46

[60] DEIR, Appendix B-3, TANKS modeling which begins at p. B-3-130

Response G1-81.46

The storage tanks were modeled based on maximum operating or working storage tank volumes. Storage tanks do not operate at their nominal capacities. The nominal capacity is the maximum physical capacity of a storage tank, the volume of the tank if it is filled to the brim. The working capacity is the volume contained within the tank up to the maximum fill level. The maximum working capacity is less than the nominal capacity because the tank also includes appurtenances and a floating roof that must fit within the nominal tank volume. The proposed project tank emissions were correctly estimated in the DEIR using the working tank capacities (see Response G1-81.47).

Comment G1-81.47

Since the existing Title V permit identifies the higher nominal tank size, but emissions were estimated using the lower size, the modeling may result in significantly underestimated emissions. The DEIR should clarify for the above and all tanks why different sizes than nominal were used in air emissions modeling (which is performed by a standard EPA computer program used to estimate air emissions from future tanks). It should clarify whether permit conditions would be added to limit tank size to the same size modeled, or should correct tank sizes used in its air modeling. If the difference is attributable to a different working capacity compared to nominal capacity, permit limits should be set at the working capacity, not the larger nominal capacity.

G1-81.47

Response G1-81.47

As part of its Title V permitting program, the SCAQMD imposes throughput and commodity limitations on tanks that store petroleum products. Because tanks cannot be filled beyond their working capacity (see Response G1-81.46); the throughput can only apply to the working volume of the tank. The tank design information (including nominal and working volumes), emission calculations, and BACT standards are evaluated by SCAQMD permitting staff. Nominal tank volumes are included in the tank descriptions, but emissions are controlled via the permit condition limitations imposed on throughput, commodity, and vapor pressure. The proposed project tank emissions were correctly estimated in the DEIR using the working tank capacities and the DEIR correctly describes the storage tanks included in the proposed project.

Comment G1-81.48

Potentially significant impacts from drastically expanded storage tanks include but are not limited to:

- The **direct air emissions** from the tanks due to a lack of estimation of emissions from cleaning and degassing (for pipelines as well), also from higher vapor pressure Bakken crude oil with additional TAC components, in addition to potential emission underestimation due to tank size discrepancy;

G1-81.48

Response G1-81.48

The comment summarizes points that were previously raised and does not include evidence to support the claim of potentially significant impacts not disclosed in the DEIR. Response G1-81.43 explains that emissions from storage tank and pipeline cleaning and degassing were accounted for within the daily operating emissions evaluated in the DEIR, because cleaning emissions are equivalent or less than the operating emissions analyzed. Control devices are used during periods of storage tank roof landings, including cleaning and degassing storage tanks and pipelines, to maintain emissions at or below "normal" daily operating conditions. As explained in detail in Responses G1-81.39 and G1-78.157, the DEIR evaluated the maximum expected emissions that would be associated with operation of the new and replacement storage tanks by evaluating a conservatively large throughput and worst-case properties including TACs of the materials to be stored in the tanks. The difference between nominal tank volume and maximum working volume are addressed in Responses G1-81.46.

Comment G1-81.49

- The **increased explosion risk from Bakken crude oil storage and handling** (identified by the US Department of Transportation as at increased risk of handling due to higher volatility, not only in railcars);[61]

G1-81.49

[61] U.S. Dept. of Transportation, Safety Alert -- January 2, 2014 Preliminary Guidance, available at: file:///C:/Users/Julia%20May/Downloads/1_2_14%20Rail_Safety_Alert%20DOT%20(1).pdf, Attachment 22

Response G1-81.49

As explained in detail in Response G1-78.157, the DEIR evaluated impacts of the new and replacement storage tanks of the proposed project based on the worst-case properties of crude oils currently and potentially processed at the Refinery, including Bakken and Canadian crude oil. Of note however, the U.S. DOT Safety Alert cited in the comment makes no reference to any explosion risks from Bakken crude oil.

There have been previous volatility issues associated with the transport of Bakken crude oil. However, regulations have since been adopted that require a reduction in volatility of Bakken crude oil that is transported. For example, in December 2014, the Industrial Commission of North Dakota issued an order regarding conditioning of Bakken crude oil and limiting the RVP of crude oil provided for transport to 13.7 RVP. Thus, Bakken crude oil transported to the West Coast will be pipeline quality (i.e., qualified for safe transport) and will not have as high a vapor pressure as the Bakken crude oil produced at the wellhead. As with other U. S. crude oil production operations, the order adopted by the State of North Dakota will require that crude oil production facilities remove a significant portion of the light ends (ethane, propane, butane and pentane) prior to offering the crude oil for shipment to refineries for processing.

Because of Bakken crude oil's purported volatility, concerns were raised in the media as to whether Bakken crude oil was properly classified as a Class 3 hazardous material under U.S. DOT regulations. A Class 3 hazardous material is generally a flammable or combustible liquid that does not meet the regulatory classification requirements for other hazardous characteristics, such as toxicity, corrosivity, radioactivity or explosiveness. However, those concerns have since been resolved by repeated analysis and testing that demonstrates Bakken crude oil to be a Class 3 hazardous material, similar to other light sweet crude oils. After considering the information, the PHMSA Deputy Administrator testified to Congress that Bakken crude oil is accurately classified as a Hazard Class 3 Flammable Liquid.[257] This is consistent with the sampling and testing Tesoro has completed on Bakken crude oil. Therefore, Bakken crude oil has properties similar to other light crude oils, and is not classified as explosive.

[257] Written statement of Timothy P. Butters Before the Subcommittees on Energy and Oversight Committee on Science, Space and Technology, U.S. House of Representatives at page 12 (Sept. 9, 2014).

Comment G1-81.50

- The **new storage potential to accommodate Canadian crude oil, providing a path to downstream refinery impacts,** including sulfidation corrosion, increased hazards and emissions from formation of additional H2S and other hazardous sulfur compounds] G1-81.50

Response G1-81.50

The comment assumes that Canadian crude oil will be stored in the new and replacement storage tanks and describes potential downstream impacts from sulfidation (or sulfidic) corrosion, increased hazards, and emissions. The storage is not to accommodate any particular source of crude oil. These issues were raised in previous comment letters and have been addressed in detail in previous responses. Response G1-78.111 addresses H_2S, hazards from sulfur compounds, and potential sulfidic corrosion and describes the measures the Refinery has put in place to manage potential hazard impacts from sulfidic corrosion. Additionally, there are other crude oil evaluations performed prior to mixing individual crude oils to ensure the suitability of the blend to be processed by the Refinery. These evaluations include the Linear Programming model, blending model, crude oil assay software, and TAN and other corrosion limitation evaluations.

Comment G1-81.51

- **The downstream impacts in the refinery due to the accommodation in the tanks of the new crude oils,** and the upstream impacts due to the production and transport of these crude oils.] G1-81.51

Response G1-81.51

The comment does not specify downstream impacts in the Refinery or provide substantial evidence that any impacts would occur. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94 the proposed project does not change the crude oil blend processed at the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Because the crude oil blend does not change significantly, even if the individual crude oils purchased change as a result of the market, there will be no associated potential impacts of processing various crude oils at the Refinery since they will be blended in order to be processed by the Refinery.

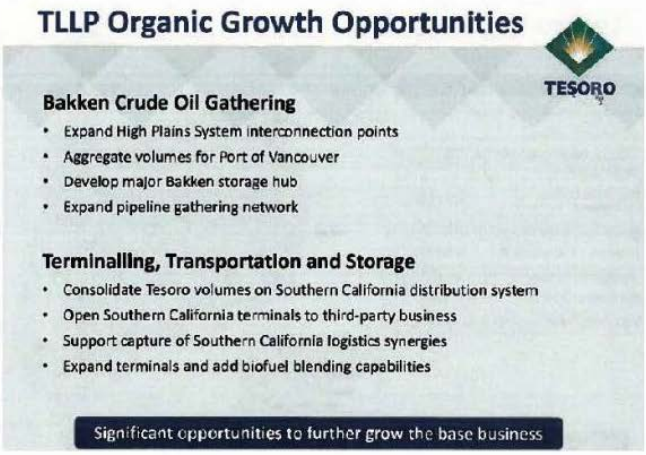
The comment also references impacts due to upstream production and transportation of crude oils. This issue is raised and addressed in more detail in Comment and Response G1-81.67. The proposed project is not designed to, and will not in fact, facilitate a switch to a new slate of crude oils to be processed by the Refinery. Since the proposed project will not result in increased crude oil production, CEQA does not require evaluation of those independent operations. Any crude oil transportation impacts are already occurring or have been evaluated in the DEIR for the projected 6,000 bbl/day increase in crude oil capacity associated with the proposed project.

Comment G1-81.52

F. Tank expansions also facilitate exports and third party sales; impacts need evaluation

Tesoro has also announced its intentions to open up its South Coast assets to third party transfers. For example, the previously cited 2014 Deutsche Banke presentation by Tesoro states it will *"**Open Southern California terminals to third-party business**, Support capture of Southern California logistics synergies, and Expand terminals and add biofuel blending capabilities."*[62]

G1-81.52



G1-81.52 cont'd.

The extremely large additional tank storage and throughput – which is above and beyond the daily crude processing volume for the entire refinery complex, is consistent with Tesoro's stated plans to pass through its terminals third-party business.

Tesoro should be required to disclose third-party business activities planned for the tank expansions, as these have downstream impacts. For example, the additional tankage would not only allow Tesoro to change its crude oil slate within its own refineries, it could also sell Bakken or Canadian crude oil to other Los Angeles refineries. Both Valero and Phillips 66 for example, have announced plans to receive these particular crude oils, previously isolated from their refineries. The Tesoro Project could open up *all* the Los Angeles refineries to these crude oils, and could become Tesoro's export terminal.

Since the Tesoro Savage Vancouver facility is slated at 360,000 bpd (or >130 million bbls/year), the increased throughput permitted for the new tanks at about 420,000 bpd would accommodate the entire daily shipment from the Tesoro Savage terminal. Tesoro could sell the excess crude to other LA refineries, or export it (since Tesoro had to agree not to export crude from the Vancouver facility on the approval of the terminal lease extension[63]).

[62] 2014 Tesoro to Deutsche Bank, *id.*, Slide 24

[63] Previously cited Oregon Public Broadcasting (OPB), April 15, 2016

Response G1-81.52

The comment combines unrelated statements regarding Tesoro Logistics business strategy and the Vancouver Energy Project and concludes incorrectly that the new and replacement crude oil storage tanks will be used to "grow" its third party business. While the first part of the slide explains logistics in the Bakken region, the second part of the slide refers to Tesoro Logistics finished product terminals (see Declaration of Douglas Miller).[258] The Tesoro Logistics product

[258] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

terminals are separate from and operate independently of the Refinery and the marine terminals. They are used to blend ethanol and biofuels and deliver transportation fuels to trucks for distribution (as noted by the reference to biofuel blending). The slide containing statements regarding Tesoro Logistics is one of many slides in a presentation to investors containing many distinct points and summaries of various aspects of Tesoro Logistics operations within California, including opening Southern California product terminals to third-party business. Therefore, the assumption in the comment that the new crude oil storage tanks will be used to grow third party sales is incorrect.

The new and replacement storage tanks of the proposed project are not located at, and are unrelated to, the Tesoro Logistics transportation fuel product terminals. Tesoro Logistics transportation fuel product terminals in the South Coast include Carson Products Terminal, Carson; Colton Terminal, Bloomington; East Hynes, Long Beach; Hathaway Terminal, Signal Hill; Wilmington Sales terminal, Wilmington; and Vinvale Terminal, Southgate. See Declaration of Holly Kranzmann for further description on the difference in the term "terminal."[259] As explained in the DEIR, the objective of the proposed additional storage capacity is to more efficiently offload marine vessels, which will reduce demurrage and reduce vessel emissions (see page 2-5 and pages 4-26 through 4-29 of the DEIR).

To the extent that the comment alludes to the alleged possibility for sale of crude oil stored at the Refinery to third parties, the proposed project is not intended to enable that practice and there is no evidence suggesting otherwise. The proposed project does not include modifications to enable the export of crude oil.

In general, the Refinery imports crude oil and produces transportation fuels such as gasoline, diesel, and jet fuel for consumption in the U.S. Marine Terminal 1 is connected to the Carson Crude Terminal via pipeline. No facilities exist or are proposed to load crude oil onto marine vessels from the storage tanks at the Carson Crude Terminal. Furthermore, Marine Terminal 1, the Refinery's large marine vessel unloading terminal, has no capabilities to load crude oil onto marine vessels. In order to load crude oil onto marine vessels, SCAQMD permits would be required to allow the installation of a marine vapor recovery system meeting the requirements of SCAQMD Rule 1142 and BACT. No such modifications are included in the proposed project to enable crude oil loading at Marine Terminal 1. Therefore, the capabilities for exporting crude oil from the marine terminals will not change with the proposed project.

The Refinery and the Carson Crude Terminal currently lack adequate storage capacity to accept full cargos when marine vessels deliver crude oil. Up to three or four of the proposed storage tanks would be utilized to offload one large marine vessel. See Sections 2.7.1.9 (page 2-39) and 2.7.2.11 (page 2-46) of the DEIR for a full description of the proposed storage tanks modifications for the project, and see Response to Comment G1-78.143 for further information on the need for storage tanks.

[259] See Attachment G, Declaration of Holly Kranzmann, Vice President, Logistics Development-West Coast, of Tesoro Logistics.

The comment speculates, without substantial evidence, on proposed project objectives, other than those stated in the DEIR. The proposed project objectives and purpose are clearly stated in Sections 2.2, 2.7.1.9, and 2.7.2.11 of the DEIR.

Finally, the Vancouver Energy Project does not involve the sale of crude oil to any third party. Rather the Vancouver Energy Project would receive its customers' crude oil, unload and stage the crude oil in onsite tanks and load the crude oil onto marine vessels arranged by its customers, see Master Response 8 that further explains this issue.

Comment G1-81.53

IV. A planned switch to Bakken crude oil and likely added tar sands crude, results in environmental impacts that should have been evaluated in the DEIR

As described above, Tesoro has business plans to import significant quantities of Bakken crude oil not currently present in the refinery. Use of this crude oil is facilitated by many Project components, including greatly increased storage with high vapor pressure limits required by Bakken crude, and through the Tesoro Savage Vancouver Energy Project. G1-81.53

The switch to Bakken has many significant impacts that should have been evaluated in the DEIR, including problems with processing waxy Bakken crude, corrosion problems, specific problems when blending Bakken crude with heavy crude oils, higher volatility that has caused explosions and fires, and higher levels of toxic components such as benzene. Bakken crude oil is also produced through hydraulic fracturing ("fracking"), which increases emissions of the potent GHG methane, which should have also been evaluated. These additional emissions from extraction add to the total global GHG burden, including impacts to the Los Angeles region. G1-81.53 cont'd.

The Project is also likely to result in significant imports of Canadian tar sands crude oil, with its own major environmental impacts, including extremely high sulfur content (causing refinery corrosion), use of toxic solvents during transport, refining problems when blending with light crude oils, and major GHG impacts due to strip mining and refining.

Response G1-81.53

The issues raised in the comment are addressed in more detail in previous or subsequent comments and are responded to in detail in responses as noted in Table 81.53-1.

Table 81.53-1

Topics Raised in Comments and Location of Responses

Topic	Response	
	Master Response Number	Specific Response Number
Storage Tank Vapor Pressure is Maximum Allowable	-	G1-81.26, G1-78.125, G1-78.131, and G1-78.152
Vancouver Energy Project Independent of the Proposed Project	8	G1-78.139
Bakken Crude Oil Not Waxy	4	G1-81.54 and G1-81.55
Bakken Crude Oil Blending	-	G1-81.56
Bakken Crude Oil Volatility and Worst-Case Impact Analysis	-	G1-81.57 and G1-78.157
Bakken Crude Oil H_2S	-	G1-81.58
Bakken and Canadian Crude Oil Hazards and Emissions	-	G1-81.59 – G1-81.63 and G1-78.111
GHG Associated with Bakken and Canadian Crude Oil Production	-	G1-86.65 and G1-86.67

Note: - = No Master Response prepared on this topic.

The comment attempts to tie Tesoro's ongoing plans to provide advantaged crude oils to its refineries to the proposed project. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. It is correct to say that Tesoro makes ongoing efforts, evidenced by its corporate statements, to provide "advantaged crude oil" to each of its U.S. refineries (see Master Response 4 for a description of "advantaged crude oil" as that term is used by Tesoro). Moreover, the proposed project does not depend on the Vancouver Energy Project, nor does Vancouver Energy Project depend on the proposed project. Each project has a separate independent purpose. The Vancouver Energy Project would not require modification to the crude oil storage tanks at the Refinery to deliver crude oil. And the Refinery can receive crude oil from marine vessels from any source, not only from the proposed Vancouver Energy Project. Since the majority of crude oil processed by the Refinery is already delivered via marine vessel, all marine deliveries will benefit from the new and replacement storage tanks.

Comment G1-81.54

A. Bakken crude impacts are extensive

1. Bakken crude oil can be waxy, resulting in transfer problems in marine vessels and storage tanks, requires chemical dispersants

An article from Hydrocarbon Processing -- *Innovative Solutions for Processing Shale Oils*[64] -- identifies problems in processing oils such as Bakken shale, due to high variability in crude qualities, waxy buildup (paraffinic content), etc. This article specifically identified transfer to refinery tankage as problematic:

> ***The paraffin content of the shale oils is impacting all transportation systems.*** *Wax deposits have been found to coat the walls of railroad tank cars, barges and trucks. Waxy deposits in pipelines regularly require pigging to maintain full throughput. Bakken shale oil is typically transported in railcar, although pipeline expansion projects are in progress to accommodate the long-term need. These railcars require regular steaming and cleaning for reuse. Similar deposits are being encountered in trucks being used for shale oil transportation.* ***The wax deposits also create problems in transferring the shale oils to refinery tankage. Fig. 4*** *shows samples of deposited wax collected from pigged pipelines*[65] *in shale oil service. [emphasis added]*

The article provided photos (entitled "waxy deposits removed from shale oil buildup") which graphically depict the more obvious problems with Bakken crude:

G1-81.54

[64] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, Attachment 23
http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html
[65] Pigging of pipelines refers to inserting mechanical devices known as "pigs" to perform various maintenance operations, including cleaning and inspection.

Response G1-81.54

Almost all crude contains some amount of wax in the heavier fractions. Typically, the waxes in marketable crude oils are totally dissolved or well suspended in the oil, otherwise they would cause fouling or plugging of oil wells, pipelines, and tanks. There are a small percentage of marketable crude oils in the world that require heating and/or chemical additions such as pour point depressant for transport and storage. Based on Tesoro's experience handling Bakken crude oil at three of its refineries (Anacortes, Washington and Dickinson and Mandan, North Dakota Refineries), Bakken crude oil does not require heating, blending, or chemical additions to keep the waxes suspended.

The comment that Bakken crude oil can be waxy was raised in other comments. Response G1-78.162 addresses this issue in detail. The comment references and relies on an article in Hydro Processing for its claims that Bakken crude oil has high paraffinic content. A closer look at the article shows that the photos and descriptions on wax deposition are focusing on shale oils from Texas and Pennsylvania, not Bakken crude oil. These other shale oils are widely known in the industry as being light crude oils containing wax crystals that can settle out of the oil because the oil has low viscosity and low density allowing the waxes to settle. Bakken crude oil is not known to have these issues or associated operating problems. Regardless, substantial evidence

does not support the assertion that the Refinery will process more Bakken crude oil as a result of the proposed project since the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or the crude oil blend processed at the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. The comment is not relevant to the proposed project and the DEIR analysis provides an accurate analysis of potential impacts from the proposed project.

Comment G1-81.55

The article also identified multiple chemical dispersants used to mitigate these problems not only during transportation, but also within refineries where these shale oils are processed:

> *To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously.*

These chemicals must be identified in order to assess the impacts of their use. The article also found that steam cleaning is used to remove such deposits from railcars. Such activities should be identified and associated impacts evaluated for impacts in marine vessels, pipelines, and storage tanks. Impacts within the refinery must also be evaluated for safety risks.

G1-81.55

Response G1-81.55

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

As described in Response G1-81.54, almost all crude contains some amount of wax in the heavier fractions, so all of Tesoro's refineries process crude oils with varying amounts of wax. Some wax and other sediments slowly build-up in all crude oil storage tank bottoms. Storage tank cleaning is performed when tank bottom build-up decreases available tank storage space and impacts operations. Tesoro reports that normally tank bottom and wax deposition is so gradual that refinery and terminal tanks do not require cleaning until a storage tank is scheduled to come out of service for mandated integrity inspections. At that time, full cleaning often consists of flushing the tank with lighter oils and chemical dispersants to dissolve deposits and recover them for processing in the refinery or for waste disposal.

Tesoro reports that its Dickinson and Mandan, North Dakota Refineries process nearly 100% Bakken crude oil and its Anacortes, Washington Refinery processes a large percentage of Bakken crude oil. Tesoro also operates numerous pipelines and terminals that gather crude oil in North Dakota and handle Bakken crude oil exclusively. None of Tesoro's facilities have reported any unusual issues with wax. Dispersants, solvents, and heating are not required to manage Bakken crude oil at Tesoro's facilities. Therefore, no additional dispersant use or marine vessel, pipeline, or storage tank cleaning activities would be expected if additional Bakken crude oil were processed within the Refinery's crude oil blend.

As indicated in Sections 2.6.1 and 2.6.2 of the DEIR, crude oil is not currently received by either the Refinery Wilmington or Carson Operations via rail. It should be noted that these locations do not currently have the facilities or SCAQMD permits to receive crude oil deliveries by rail and no new or modified facilities are included in the proposed project to enable crude oil deliveries by rail. Crude oil railcar cleaning activities are not associated with the proposed project or the Refinery.

Comment G1-81.56

2. When Bakken crude oil is blended with heavier crudes, it can cause asphaltene destabilization, resulting in corrosion, fouling of refinery preheaters, heat exchangers, and furnaces, and can cause refinery shutdowns

The Hydrocarbon Processing article found that asphaltene destabilization can occur when blending shale oil with heavier crudes. This is precisely the kind of blending that could occur due to the Project, through the blending of waxy, light Bakken crude oils, with heavier crude oils processed at the refinery, including California heavy, and potentially Canadian tar sands.

These problems result in fouling of the cold preheat train, fouling of hot preheat exchangers and furnaces, problems in transportation, storage, refinery corrosion, and crude unit shutdowns. These oils are also extracted through fracturing, which have additional and major impacts on water, air, and the global climate. The article finds:

> *The refining of shale oil (also known as tight oil) extracted through fracturing from fields such as Eagle Ford, Utica and* ***Bakken*** *has become prevalent in many areas of the US.* ***Although these oils are appealing as refinery feedstocks due to their availability and low cost, processing can be more difficult.***
>
> ***The quality of the shale oils is highly variable. These oils can be high in solids with high melting point waxes.*** *The light paraffinic nature of shale oils can lead to asphaltene destabilization when blended with heavier crudes. These compositional factors have resulted in cold preheat train fouling, desalter upsets, and fouling of hot preheat exchangers and furnaces. Problems in transportation and storage, finished-product quality, as well as refinery corrosion, have also been reported. Operational issues have led to cases of reduced throughput and crude unit shutdowns. The problems encountered with shale oil processing and possible prediction and control strategies will be presented.* [Emphasis added throughout]

G1-81.56

The article found use of shale oils was particularly problematic when blended with heavy crudes, which is admittedly planned by Tesoro for its California refinery operations. This blending can cause agglomeration of large molecules onto surfaces inside refinery units which can crack and leave coke-like deposits if the surfaces are hot.[66] Coke deposits lead to poor operation and can cause shut down of units before planned maintenance periods. All these problems require special handling and planning at the refinery. In addition, the article found shale oils to be highly variable in certain characteristics including for example, its solids content, and others. The article states:

> *Due to their paraffinic nature, mixing shale oil with asphaltenic oil leads to destabilization of the asphaltene cores. Asphaltenes are polar compounds that influence emulsion stability. Once the asphaltenes destabilize, they can agglomerate, leading to larger macro-molecules. On hot surfaces, agglomerated asphaltenes easily crack or dehydrogenate and gradually form coke-like deposits.*

G1-81.56 cont'd.

[66] Coke is a petroleum product that is mostly the carbon leftover after making gasoline from crude oil. Coke is a fuel, and similar to coal, as an energy source that results in high GHG and criteria pollutant emissions, and significant heavy metal content.

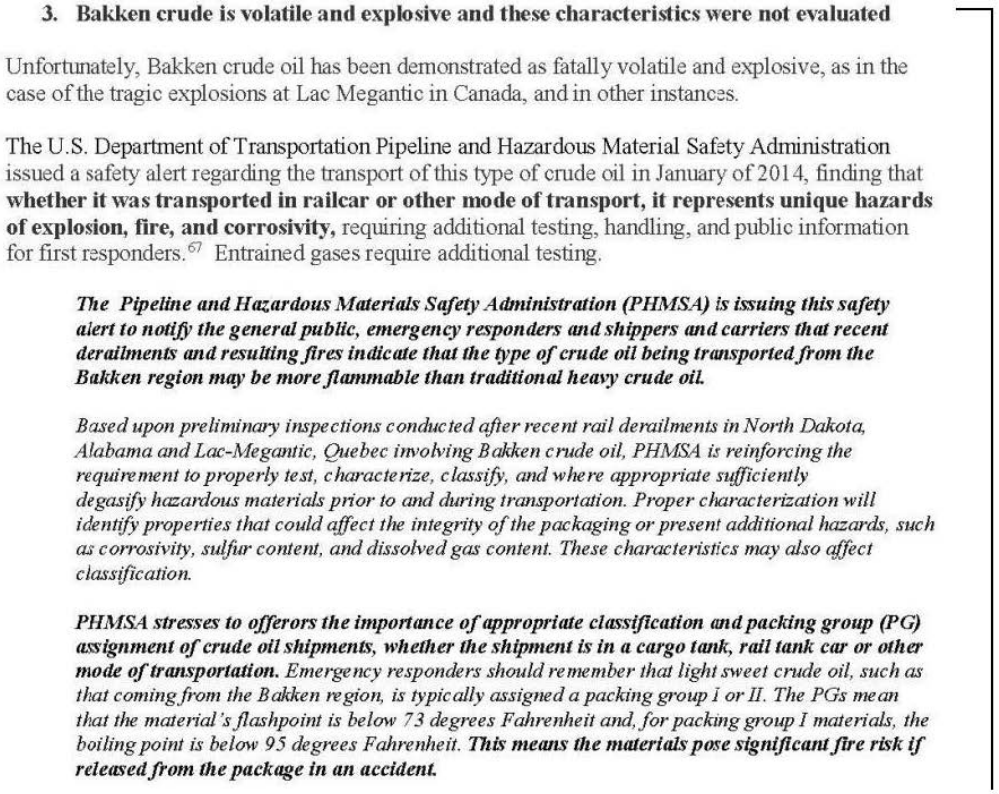
Response G1-81.56

The comment that Bakken crude oil blending with heavier crude oils can result in asphaltene destabilization was raised in other comments. Response G1-78.170 addresses this issue in detail. The comment relies on the Hydrocarbon Processing article referenced in Comment G1-81.54 for its claims that Bakken crude oil blending can result in asphaltene destabilization. Asphaltene

precipitation from blending of incompatible crude oils is a well-recognized issue in the refining industry.

Tesoro and other refiners use blending models to predict and avoid incompatible blends. The compatibility models used by Tesoro are propriety models from Soluble Solutions[260], a company that provides crude oil testing, blending rules and models, and consultation. The Refinery has used these compatibility models for many years as the historic and current crude oil slates could be incompatible if blended incorrectly. These models have been effective in eliminating equipment fouling from asphaltene deposits and asphaltene deposits are not expected to be an issue in the future since the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

Comment G1-81.57



3. Bakken crude is volatile and explosive and these characteristics were not evaluated

Unfortunately, Bakken crude oil has been demonstrated as fatally volatile and explosive, as in the case of the tragic explosions at Lac Megantic in Canada, and in other instances.

The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration issued a safety alert regarding the transport of this type of crude oil in January of 2014, finding that **whether it was transported in railcar or other mode of transport, it represents unique hazards of explosion, fire, and corrosivity,** requiring additional testing, handling, and public information for first responders.[67] Entrained gases require additional testing.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert to notify the general public, emergency responders and shippers and carriers that recent derailments and resulting fires indicate that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.

Based upon preliminary inspections conducted after recent rail derailments in North Dakota, Alabama and Lac-Megantic, Quebec involving Bakken crude oil, PHMSA is reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. Proper characterization will identify properties that could affect the integrity of the packaging or present additional hazards, such as corrosivity, sulfur content, and dissolved gas content. These characteristics may also affect classification.

PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, whether the shipment is in a cargo tank, rail tank car or other mode of transportation. *Emergency responders should remember that light sweet crude oil, such as that coming from the Bakken region, is typically assigned a packing group I or II. The PGs mean that the material's flashpoint is below 73 degrees Fahrenheit and, for packing group I materials, the boiling point is below 95 degrees Fahrenheit.* ***This means the materials pose significant fire risk if released from the package in an accident.***

G1-81.57

[260] www.solublesolutions.com.

> *. . . Based on initial field observations, PHMSA expanded the scope of lab testing to include other factors that affect proper characterization and classification such as* ***Reid Vapor Pressure, corrosivity, hydrogen sulfide content and composition/concentration of the entrained gases*** *in the material. The results of this expanded testing will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any unique hazards of the materials will enable offerors, carriers, first responders, as well as PHMSA and FRA to identify any appropriate mitigating measures that need to be taken to ensure the continued safe transportation of these materials.*

This is a major potential problem that the DEIR must evaluate, at Tesoro's LA region marine terminals, in the expanded pipeline to the refinery, in the storage tanks at the refinery, and in the refinery where it will be used. Since the Lac Megantic rail explosion tragedy, many other crude by rail explosions and spills have happened across the U.S., even after new safety regulations were adopted.

In fact, just one week before the comment deadline on the Tesoro LARIC Project, yet another crude oil railcar bearing Bakken crude oil below up in Oregon along the Columbia River gorge, very near an elementary school and houses (photos shown below). This was just up the Columbia River (about 70 miles) from the proposed Tesoro Savage Vancouver terminal, which would transport large volumes of the same Bakken crude oil, by rail.

KIRO7 Seattle, Oil train derails in Oregon's Columbia River Gorge, Updated Jun 3, 2016 - 2:32 PM, http://www.kiro7.com/news/local/oil-train-derails-oregons-columbia-river-gorge/320955970

G1-81.57 cont'd.

Updated reporting found that crude oil did reach the Columbia River, after contaminating the local water supply:[68]

> "The main sewer line that leads to the wastewater treatment plant was damaged during the derailment," said David Byers, the Washington state Department of Ecology response manager. So far, cleanup crews have cleaned about 10,000 gallons of crude oil out of the town's sewage system. Another 32,000 gallons burned off or vaporized in the initial crash, was captured by booms in the Columbia, or soaked into the soil.

http://www.kgw.com/news/photos-train-derailment-in-the-gorge/230445267

Vancouver, Washington proposed Tesoro Savage Bakken and other crude-by-rail to ship terminal, just up the Columbia River from the June 3, 2016 Bakken crude railcar explosion along the Columbia.

G1-81.57 cont'd.

[67] The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, January 2, 2014, http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_111F295A99DD05D9B698AE8968F7C1742DC70000/filename/1_2_14%20Rail_Safety_Alert.pdf , Attachment 24

[68] Oregon Public Broadcasting (OPB), 6/7/2016, New Spilled Crude Oil Discovered At Mosier Train Crash, http://www.opb.org/news/series/oil-trains/oregon-oil-train-mosier-derailment-cleanup-spill/ Attachment 25

Response G1-81.57

As explained in detail in Sections 2.5.3 and 2.5.4 of the DEIR, and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing blends of various crude oils and the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Thus, the proposed project will not cause a significant change in the crude oil transported to the Refinery. Accordingly, the DEIR need not include analysis of risks posed by increased transport, storage, or handling of particular types of crude oil because the proposed project will not increase transport, storage, or handling of any particular type of crude oil.

The comment references several accidents resulting after crude oil train derailments. As noted in Response G1-81.55, crude oil is not received by the Refinery via rail, nor does the proposed project include modifications to enable crude oil to be received by rail at the Refinery. The comment is unrelated to the proposed project. However, numerous misstatements and

generalizations regarding Bakken crude oil are made in the comment that should be addressed and corrected.

The comment claims that Bakken crude oil is uniquely volatile and explosive and references a January 2, 2014 PHMSA safety alert. However, the comment adds conclusory "findings" that are not found in the PHMSA safety alert.[261] The comment summarizes the alert, "…finding that whether it was transported in railcar or other mode of transport, it represents unique hazards of explosion, fire, and corrosivity, requiring additional testing, handling, and public information for first responders." The comment attributes findings to the PHMSA safety alert that were not made in the safety alert.

Actually, the early 2014 PHMSA alert noted the possibility, not the conclusion, that crude oil transported from the Bakken region may be more flammable than *traditional heavy crude oil*, based on recent derailment and fire incidents, not laboratory testing of Bakken crude oil properties. The alert did not indicate that Bakken crude oil presents different hazards from those of other light crude oils. The PHMSA alert's guidance concerned the accurate classification of materials being transported, whatever their properties and risks. The alert provided that, "…it is imperative that offerors properly classify and describe hazardous materials offered for transportation. … PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, *whether the shipment is in a cargo tank, rail car or other mode of transportation.*" The article continues to explain that PHMSA and the Federal Railroad Administration (FRA) initiated "Operation Classification," a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that the materials have been properly classified and that the agencies expanded the scope of their testing to measure other factors that would affect the proper characterization and classification of these materials. Again, the alert emphasized that testing sufficient to draw conclusions regarding the properties of Bakken crude oil had not been completed, stating only that, "PHMSA expects to have final test results in the near future for the gas content, *corrosivity*, toxicity, flammability, and certain other characteristics of Bakken crude oil, which should more clearly inform the proper characterization of the material. . . . The results of this *expanded testing* will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any *unique* hazards of the materials will enable offerors, *first responders*, as well as PHMSA and FRA to identify any mitigating measures that need to be taken to ensure the continued safe transportation of these materials. [*emphasis added*]" It should be noted that the terms "explosive" and "explosion" are not used in the safety alert.

It is also important to understand the results of the additional testing summarized in PHMSA's safety alert. Response G1-78.160 addresses volatility of Bakken crude oil in detail and PHMSA's conclusion following its evaluation of Bakken crude oil test results. There are several recent evaluations that conclude that Bakken crude oil is typical of other light crude oils. This is the conclusion of the article: A Survey of Bakken Crude Oil Characteristics Assembled for the

[261] U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, Safety Alert -- January 2, 2014, phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/1_2_14%20Rail_Safety_Alert.pdf.

U.S. Department of Transportation.[262] Because of Bakken crude oil's purported volatility, concerns were raised in the media as to whether Bakken crude oil was properly classified as a Class 3 hazardous material under U.S. DOT regulations, which generally refers to a flammable or combustible liquid that does not meet the regulatory classification requirements for other hazardous characteristics, such as toxicity, corrosivity, radioactivity or explosiveness. However, those concerns have since been resolved by repeated analysis and testing that demonstrates Bakken crude oil to be a Class 3 hazardous material, similar to other light sweet crude oils. After considering the information, the PHMSA Deputy Administrator testified to Congress that Bakken crude oil is accurately classified as a Hazard Class 3 Flammable Liquid.[263]

The comment also refers to derailment of a train carrying Bakken crude oil in Mosier, Oregon. Because there are no proposed project modifications to bring crude oil by rail to the Refinery, the Mosier derailment is not relevant to the DEIR analysis or the proposed project. The FRA's preliminary report identified a railroad track issue as the cause of the Mosier incident[264]; therefore, there are no resulting mitigations that would need to be considered for the proposed project.

The comment also notes that Mosier is approximately 70 miles from the proposed Vancouver Energy Project. As described in Master Response 8, the Final EIS has not yet been issued for the Vancouver Energy Project, nor has the project been approved. Additionally, as explained in Section 4.1.2.5 of the DEIR, the Vancouver Energy Project is wholly independent from the proposed project and is undergoing separate environmental review by the Washington State EFSEC.

Most importantly, the proposed project will not facilitate the increased processing of Bakken crude oil, or any other specific crude oil, at the Refinery. Future changes in the Refinery's crude oil slate, if any, will occur independently of the proposed project, and will be based on factors that cannot be predicted, such as the relative cost and availability of different crude oils in the future. Thus, any attempt to identify impacts from a hypothetical future change in crude oil slate would be entirely speculative.

[262] A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation, American Fuel and Petrochemical Manufacturers, May 2014.

[263] Written statement of Timothy P. Butters Before the Subcommittees on Energy and Oversight Committee on Science, Space and Technology, U.S. House of Representatives at page 12 (Sept. 9, 2014).

[264] https://www.fra.dot.gov/eLib/details/L18393#p1_z50_gD_lAC, accessed November 7, 2016.

Comment G1-81.58

4. Bakken crude refining can also increase levels of acutely hazardous and corrosive Hydrogen Sulfide in the refinery

The Hydrocarbon Processing article also identified increased levels of extremely hazardous hydrogen sulfide (H2S) gas as a problem associated with shale oil. Furthermore, when scavenging agents are used to reduce H2S presence, these can cause corrosion and form solid deposits inside processing units. The article states:

> ***Several shale oil production locations have high H_2S loading.*** *To ensure worker safety, scavengers are often used to reduce H_2S concentrations. The scavengers are often amine-based products—methyl triazine, for instance—that are converted into mono-ethanolamine (MEA) in the crude distillation unit (CDU). Unfortunately, these amines contribute to corrosion problems in the CDU. Once MEA forms, it rapidly reacts with chlorine to form chloride salts. These salts lose solubility in the hydrocarbon phase and become solids at the processing temperatures of the atmospheric CD towers and form deposits on the trays or overhead system.* ***The deposits are hygroscopic, and, once water is absorbed, the deposits become very corrosive.*** *These physical properties are responsible for the problems that are being experienced by refineries handling shale oils.*

G1-81.58

Hydrogen sulfide is deadly, corrosive, causes odor complaints when released, and its increase in the refinery certainly requires specific evaluation that was absent in the ND.

A report by Bakkenshale.com found:[69]

> *Is the Bakken producing higher volumes of H2S? That's the question you have to ask yourself when you see pipelines implementing H2S standards for the first time.*
>
> *On May 8, Enbridge submitted an emergency application to the Federal Energy Regulation Commission (FERC) asking to amend its conditions of carriage to 5 ppm of H2S or less. If accepted, Enbridge would have the right to reject crude with higher levels of H2S. . . .*
>
> ***Enbridge acted after it found concentrations of 1,200 ppm in a crude tank at its Berthold Terminal. 20 ppm is the limit allowed by OHSA and an average of 10 ppm of exposure is all that is allowed over an 8-hour work day.***
>
> *Both Plains Marketing and Murex Petroleum objected to the FERC application, but it looks as if they solved their differences when Enbridge notified FERC it wasn't planning an outright ban on crude with higher H2S concentrations. The two companies weren't against the change, but were afraid they couldn't comply in the time frame planned.*

G1-81.58 cont'd.

The Chemical Safety Board report also identified that H2S was a particularly aggressive corrosive agent.[70] These issues must be evaluated through a full EIR to prevent severe safety risks associated with crude slate changes.

The problem of sulfur corrosion increasing accident risk was unfortunately born out at Chevron Richmond in California last August, when a major explosion barely avoided killing 19 workers, but did send 15,000 neighbors to the hospital after a huge black plume traveling many miles through the Bay Area resulted from the crude unit explosion, which burned for many hours.

Steelworkers testified at the U.S. Chemical Safety Board hearing on the Chevron explosion that such sulfur corrosion is a statewide problem at California oil refineries.[71] The Chemical Safety Board found that the Richmond accident was caused by sulfur corrosion that Chevron had been aware of, and had repeatedly ignored, and the report showed that sulfur content had increased. The photos below show the heavy impact not only in Richmond, but across the San Francisco Bay Area due to this accident.

A discussion of corrosion issues at oil refineries due to increased sulfur content in crude oil, and other important related issues was provided in the attached report of Greg Karras on the Phillips 66 *Rodeo* refinery EIR.[72] Also refer to the previously cited report of Dr. Fox on impacts of use of

"advantaged.".

These reports demonstrate in further detail the impacts of corrosion demonstrated by the US Chemical Safety Board, causing the massive explosion in August of 2012 in the Chevron Richmond refinery, pictured below. The U.S. Chemical Safety Board report is also available.[73] The significance of the air pollution impacts caused by the Chevron explosion are self-explanatory, in the photos below of the August 2012 explosion caused by the refinery corrosion.

G1-81.58 cont'd.

[69] May 30, 2013, http://bakkenshale.com/pipeline-midstream-news/bakken-producing-sour-gas-h2s-problem-in-north-dakota/
[70] *Id.* at p. 33
[71] U.S. Chemical Safety Board transcript of public hearing on Chevron Richmond, CA August 2012 explosion and fire, page 225, http://www.csb.gov/assets/1/19/0503CSB-Meeting.pdf
[72] Expert Report of Greg Karras, CBE, 4 September 2013, Regarding the Phillips 66 Company Propane Recovery Project Draft Environmental Impact Report released in June 2013 by the Contra Costa County Department of Conservation and Development
[73] Interim Investigation Report, Chevron Richmond Refinery Fire, (which as adopted at the July public hearing) available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf

Response G1-81.58

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or the crude oil blend processed at the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Thus, the proposed project will not result in a significant change in the crude oil properties managed by the Refinery. Accordingly, the DEIR need not include analysis of odors posed by increased transport, storage, or handling of particular types of crude oil because the proposed project will not increase transport, storage, or handling of any particular type of crude oil. Master Response 11 further addresses potential odors associated with the proposed project.

The comment incorrectly claims that Bakken crude oil can increase levels of H_2S in the Refinery and cites the Hydrocarbon Processing article referenced in Comment G1-81.54 as its information source. As noted in Response G1-81.54, a close look at the article shows that many comments in the article are focusing on shale oils from Texas and Pennsylvania, not Bakken crude oil. The second paragraph of the article begins, "The quality of the shale oils is highly variable." The comment provides no data on the H_2S content of Bakken compared to other crude oils. However, other sources confirm that the H_2S content of Bakken crude oil is actually less than

most other crude oils. The North Dakota Petroleum Council carried out a study of Bakken crude oil properties and found the range of H_2S in Bakken is less than 10 ppm, and the typical value is less than 1 ppm.[265] These are low levels, below the detection limits of some of the test methods. The levels of H_2S in Bakken crude oil are lower than or comparable to concentrations of H_2S found in other crude oils delivered to the Refinery, which are typically low, usually less than 5 ppm, the lower detection limit of the laboratory method used to determine H_2S in crude oil (see Response G1-78.111).

PHMSA requested that the Transportation Research Board (TRB) produce a study on the transportation of heavy Canadian dilbit (tar sands) crude oil, in the U.S.[266] This study also provides H_2S and other data on other types of crude oils. The TRB found that the sulfur, acidity, H_2S content, and other properties are within the range of other crude oils and that heavy Canadian crude oil is as safe as any other crude oil for transportation in pipeline systems. The graph on p. 45 of the study compares the H_2S content of heavy Canadian crude oil to other crude oils, and shows that the Bakken H_2S content of less than 10 ppm (with typical values less than 1ppm) place it on the low end of the H_2S spectrum for crude oils. The findings of the TRB study support the conclusions that the H_2S content of Bakken is low and would not cause any increased risk to corrosion or spills in the transportation sector or increase the sulfur or H2S content of the crude oil blend processed by the Refinery.

The cited Hydrocarbon Processing article mentions "Several shale oil production locations have high H_2S loading". There are thousands of shale oil production locations across the U.S., including some with higher H_2S concentrations that get treated with scavengers. There is also substantial dilution as the production from an individual well is combined with other crude oil produced from other wells; and any high levels of H_2S are quickly diluted away.

The Bakkenshale.com reference mentions a terminal at Berthold. Crude oil production terminals typically receive crude oil that is trucked in from many wells. There are crude oils produced in North Dakota that are from conventional wells that have been producing oil for decades. Some of these crude oils have high H_2S content. The Bakkenshale.com article does not provide any evidence that Bakken crude oil contains high levels of H_2S.

Although not necessarily related to Bakken crude oil, the comment raises issues regarding H_2S and sulfur corrosion that have been raised in other comments. Response G1-78.111 addresses in detail the evaluations that the Refinery performs on the crude oil blends it plans to process to ensure that feed to downstream units stays within the sulfur compound content operating limits of the various units. Additionally, Response G1-78.111 describes the inspections that are performed on Refinery equipment and piping to specifically address the type of corrosion that caused the Chevron Richmond incident and to ensure equipment integrity for processing crude oil blends at the Refinery.

[265] https://www.ndoil.org/resources/bkn/.

[266] Effects of Diluted Bitumen on Crude Oil Transmission Pipelines, http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/Dilbit_1_Transmittal_to_Congress.pdf.

Comment G1-81.59

B. Another "advantaged" crude oil from Canadian Tar Sands, which Tesoro can import through its Tesoro Savage terminal project, would cause major impacts

Although Tesoro has stated its main plan is to bring Bakken crude to its West Coast refineries, Tesoro will also have easy access to cheap Canadian tar sands crude through the Tesoro Savage terminal. Tesoro also has options previously discussed for blending with Bakken crude to approximate and replace ANS, and which could also displace heavy California crudes. Canadian tar sands crude is even cheaper than Bakken, as discussed by Bloomberg when talking about Tesoro's plans to use the cost advantage of Canadian heavy crude in California.

G1-81.59

> ***U.S. West Coast refiners including Tesoro Corp. (TSO) and Valero Energy Corp. (VLO) are developing projects to bring in more oil by rail from reserves across the middle of the U.S. and Canada to displace more expensive supplies.*** *Crude production in PADD 5, which includes California and Alaska, has dropped every year since 2002 while drillers are extracting record volumes from shale in states including North Dakota and Texas.*
>
> *The surging flows of domestic oil to California "reflect a continuing improvement in crude-by-rail receiving facilities here," David Hackett, president of Stillwater Associates, an energy consultant, said by phone from Irvine, California.*
>
> *Lower Costs*
> *Crude from North Dakota and Canada trades at a discount to Alaska North Slope oil, which rose 36 cents to $107.78 a barrel at 9:09 a.m., data compiled by Bloomberg show.* ***Western Canada Select, a heavy, sour blend, gained 36 cents to $82.88.*** *North Dakota's Bakken crude also gained 36 cents to $95.28. It costs $9 to $10.50 a barrel to send North Dakota's Bakken oil by rail to California, according to Tesoro, the West Coast's largest refiner.*

Note that this article finds both production of Alaska (lighter) crude and California (heavier crude) declining, and that these could be replaced by Bakken (lighter) crude and Canadian (heavier crude). Of course, tar sands crude oil causes major environmental damage during its mining in Canada, as described by the World Resources Institute, which rather mildly states the severe impacts:[74] "*The local and regional environmental impacts of heavy oil and tar sands production can include: significant water consumption, massive earth moving and ecosystem disturbance, increased criteria and other air pollution, and release of heavy metals and toxic materials.*"

G1-81.59 cont'd.

The DEIR must account for both the local Los Angeles region, and global impacts. Canadian tar sands are even heavier than most heavy conventional crudes (higher carbon content, requiring additional energy to process and increasing emissions) and have higher sulfur content. Contaminants must be removed during refining, which increases hazardous materials present within the refinery and can lead to dangerous corrosion within refinery operations units. These also increase the energy needed for refining, resulting in higher greenhouse gas and smog-precursor emissions. The corrosion hazard is increased due to the higher sulfur content, increasing refinery accident risk identified by the US Chemical Safety Board in the last section.

[74] http://www.wri.org/publication/content/10339

Response G1-81.59

The comment assumes that the Refinery will be processing significant quantities of Bakken and heavy Canadian crude oil as a result of the proposed project. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, or the crude oil slate delivered to the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

As stated in Response G1-78.94, it is correct to say that Tesoro makes ongoing efforts to provide "advantaged crude oil" to each of its U.S. refineries (see Master Response 4 for a description of

"advantaged crude oil" as that term is used by Tesoro). Providing "advantaged crude oil," as used by Tesoro, to Tesoro refineries, including the Los Angeles Refinery, is occurring independent of the proposed project.

The DEIR provides a summary of constraints on Refinery operations that limit the amount of light and heavy crude oil that can be blended to be processed by the Refinery (see pages 2-16 through 2-19 of the DEIR). With the exception of the 6,000 bbl/day potential crude oil capacity increase associated with the planned increase in the permit-described fired duty of the DCU H-100 heater that was analyzed in the DEIR, the proposed project does not include project elements that will remove the Refinery crude oil processing constraints. Therefore, the amount of light and heavy crude oil that can be processed by the Refinery operations will remain limited after implementation of the proposed project.

The comment states that the Refinery can blend heavy Canadian and Bakken crude oils to approximate and replace ANS crude oil. This statement has been made in prior comments and is addressed in detail in Response G1-78.150. Based on Tesoro's proprietary crude oil assay software program which shows the properties of these crude oil blends, some physical properties of these crude oil blends are similar to ANS crude oil. However, there are substantial differences in sulfur content, nitrogen content, and viscosity between the crude oil blends and ANS crude oil, additional crude oils would need to be added to make a blend that would be suitable for processing at the Refinery. As a result of this necessary blending of crude oils to meet current and continuing Refinery constraints, there will be no additional environmental impacts caused by the proposed project other than those fully described and analyzed in the DEIR. It should be noted that the comment also suggests other crude oil properties, including sulfur content and other contaminants, will have impacts that require evaluation in the DEIR. Responses to prior comments have addressed all of these properties, and Table 78.94-1 lists crude oil properties and the location of related responses.

Attachment C, the Declaration of Douglas Miller,[267] explains that Tesoro's corporate statements and newspaper articles do not support an undisclosed intention to increase transportation of Bakken and heavy Canadian crude oils to the Los Angeles Refinery as a result of the proposed project. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery.

The comment quotes a Bloomberg article that is not cited, and therefore, the quotes cannot be verified. The comment claims based on the Bloomberg article, that production of crude oil from PADD 5, which includes Alaska and California, is declining. Figure 81.59-1 confirms that production of Alaska crude oil continues to decline. However, California crude oil production has leveled and remains steady in recent years. Response G1-78.178 provides a detailed summary of California crude oil production in response to previous comments on this issue, and demonstrates that California crude oil production has remained level in recent years.

[267] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

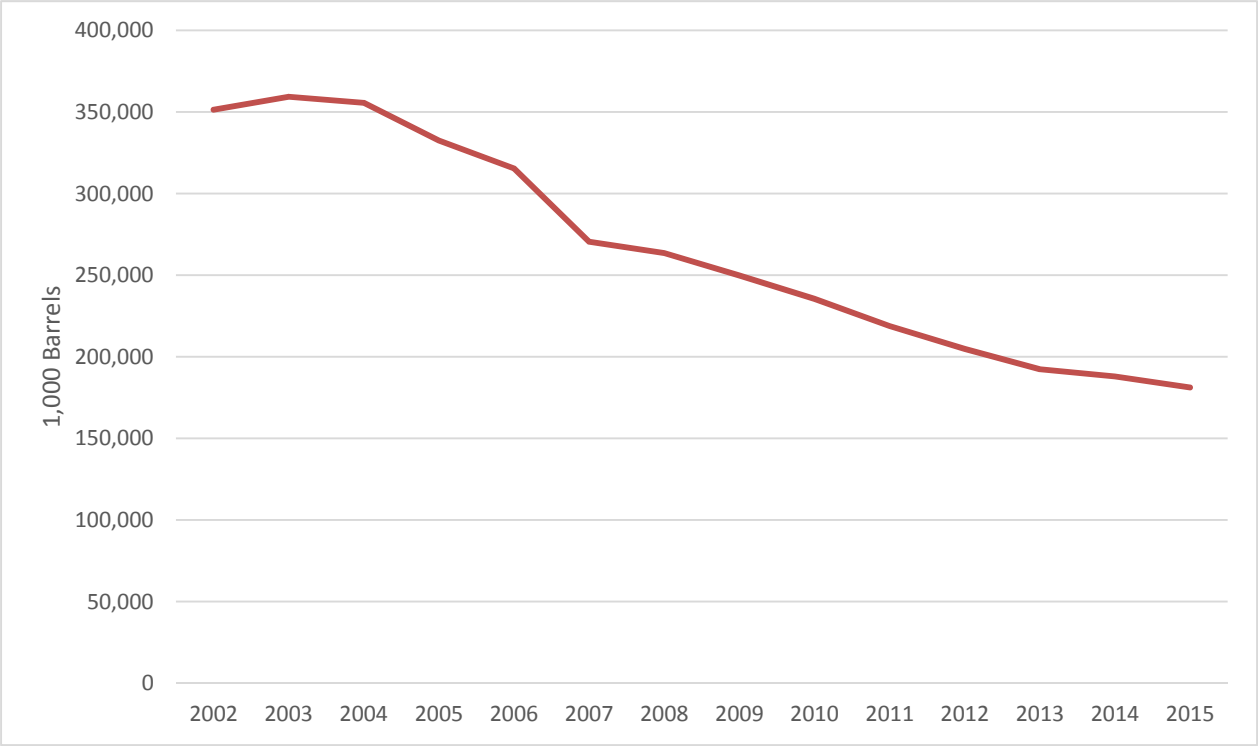


Figure 81.59-1

Alaska Crude Oil Production
2002-2015

California crude oil is competitively priced with other crude oils such that it is attractive for local refiners to purchase (see Figure 78.178-2 and the Declaration of Douglas Miller[268]). Therefore, the comment's claim that declining California crude oils will be replaced with Canadian crude oils is incorrect and unsupported by evidence.

As shown in Figure 81.59-1, Alaskan crude oil production has declined significantly in the last 15 years. The Refinery is already processing other light crude oils to replace the ANS crude oil previously processed. For example, as illustrated in Comment G1-81.36, the Refinery processes a substantial amount of light Basrah crude oil. While a limited amount of Bakken crude oil can be processed by the Refinery, many other light crude oils can also be included in the crude oil blend processed by the Refinery. The proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. The proposed project is not dependent upon processing any particular type of crude oil.

[268] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

The comment also references impacts that are addressed in previous responses. As explained in Response G1-78.146, the properties of heavy Canadian dilbit (tar sands) crude oils are similar to other conventional crude oils processed by the Refinery. As noted in Table 78.146-1, heavy Canadian crude oils are typical of other heavy, sour crude oils in their composition and, therefore, are like other crude oils. Impacts due to upstream production and transportation of crude oils are addressed in detail in Response G1-81.67. Potential impacts related to the sulfur and other contaminants in crude oils are addressed in detail in Responses G1-78.111, G1-78.171, and G1-78.172.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and will continue to do so with or without the proposed project. The proposed project will not result in a substantial change in the crude oil blend processed by the Refinery. Because the crude oil blend processed by the Refinery will not change substantially as a result of the proposed project, there are no additional environmental impacts requiring analysis as claimed in the comment.

Comment G1-81.60

The DEIR failed to evaluate the increases in desulfurization processes within the refinery due to higher sulfur content, as well as additional cracking, coking, and additional use of hydrogen, all of which require more energy and increase criteria and toxic pollutant emissions. The DEIR instead stated that the refinery has limits on the amount of heavy and light crude it can use. This is true, but within the refinery is a large range of crudes, discussed earlier in this report. The point is not the refinery's capability, but the refinery's baseline operations of the past, and how the Project will basically "debottleneck" access to different crude oils, for example by providing new storage (and transportation) of these crudes. The potential for change above the baseline needs evaluation.] G1-81.60

Response G1-81.60

Chapter 4 of the DEIR analyzed the effects of potential changes in operations associated with the proposed project including the increased utilization of processing units downstream of the proposed project components (referred to in the DEIR as direct and indirect effects, see Section 4.1.1 and 4.1.2 of the DEIR). For example, the 6,000 bbl/day potential crude oil capacity increase associated with the planned increase in the permit-described fired duty of the DCU H-100 heater was fully analyzed in the DEIR, for both direct effects of allowing increased heater firing and for indirect effects of additional processing in downstream units, including the SRPs. Desulfurization and cracking units were among the many units analyzed in the DEIR (see, for example, emission changes detailed by unit or equipment in Table 4.2-4 of the DEIR).

The comment raises issues about the different crude oils processed by the Refinery. Master Response 4 provides a detailed description of the many different types of crude oil blends processed at the Refinery. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery processes a large variety of crude oils in a crude oil blend to maintain a consistent feed to the Crude Units that is within the operating envelope of the Refinery. The proposed project will not modify the crude oil operating envelope of the Refinery. Response G1-78.100 describes the crude oil selection process that the

Refinery does and will continue to implement to ensure the crude oils purchased are capable of being blended and processed at the Refinery.

Figures 2-6 and 2-7of the DEIR show the basic properties (sulfur and API gravity) of the crude oil blends that were processed by the Refinery in the baseline. Figures 2-6 and 2-7 show that these properties may change, but they fall within the operating envelope, or ranges of crude oil properties, capable of being processed by the Refinery. The data clearly show that the Refinery has processed crude oil blends with properties throughout the operating envelope. Average crude oil properties do not represent the variety of crude oil blends that fit within the Refinery's operating envelope.

Responses G1-81.34 and G1-81.36 address the Refinery crude oil baseline issue raised in the comment and explain that due to the fixed nature of the crude oil operating envelope that will exist before and after the proposed project, baseline data regarding the crude oils comprising the blend are not necessary to conduct the impact analysis in the DEIR and was not relied upon in the analysis of impacts. Additionally, Response G1-81.36 notes that the crude oil baseline is trade secret, confidential business information, was not relied or or provided to the SCAWMD, and need be provided.

The comment also inaccurately claims that the proposed project "debottlenecks" access to different crude oils. As described in Response G1-78.136, the proposed project will not facilitate unloading, storing or processing a lighter (or different) crude oil blend at the Refinery. The Refinery already imports crude oils to the Refinery from around the world (see Master Response 4, Table G0-2.4-1). The proposed project would enable more efficient offloading of any crude oil transported via marine vessel, not any particular crude oil.

Comment G1-81.61

An Oil & Gas Journal article *Special Report: Refiners processing heavy crudes can experience crude distillation problems* (Oil and Gas Journal),[75] also identified the need for additional desalting and temperature controls in order to process unconventional crude oils. This and the other articles identified many problems with processing unconventional crudes, emphasizing that it is not just *volume* of crude throughput that determines environmental impacts, but also the characteristics or *quality* of the particular crude oil. The Oil and Gas Journal article also identified a number of differences in the content of unconventional crudes (such as tar sands and others):

G1-81.61

> *increased from less than 1 ppm to 5-10 ppm with heavy Venezuelan crudes.[1]* ***High feed-stream contaminants can reduce run length to less than half the planned turnaround interval.*** *Optimizing the atmospheric column flash-zone and wash section, and the vacuum unit design can reduce CFHT feed vanadium by 30-40%. . . .*
>
> *Heavy crudes have higher viscosities, some have higher salt content, several have high naphthenic acid content, and they are all more difficult to distill than lighter crude blends. Some upgrader crudes also have lower thermal stability than conventional crudes and higher fouling tendencies due to the increased likelihood of asphaltene precipitation. . . .*
>
> *High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability.*

G1-81.61 cont'd.

A complete inventory and evaluation of specific crude oils previously processed and to be processed at the refinery due to the Project changes needs to be evaluated for environmental impacts.

[75] Oil and Gas Journal, Special Report: Refiners processing heavy crudes can experience crude distillation problems, 11/18/2002, available at http://www.ogj.com/articles/print/volume-100/issue-47/special-report/special-report-refiners-processing-heavy-crudes-can-experience-crude-distillation-problems.html , Attachment 26

Response G1-81.61

The comment cites an Oil and Gas Journal article regarding refinery issues that can be associated with processing heavy crude oil. A close review of the article reveals that it describes challenges that may be encountered when changing a refinery's crude oil blend to process a heavier crude oil blend. The Oil and Gas Journal article cited identifies recommended design changes to enable successful processing of a heavier blend of crude oil, "This article addresses crude distillation unit (CDU) problem areas and identifies specific sections requiring investment to maintain profitability throughout a 4 - 5 year run length for refiners processing heavier crudes. … Revamps to process heavy crudes must carefully consider the flow scheme and equipment design in order to maintain crude charge rate, product yield and quality, and unit reliability." The article specifically addresses CDU revamps (changes) necessary for a refinery to process a heavier blend of crude oil. Additionally, the article refers to heavy crude oils in general, not just unconventional or blended crude oil, such as heavy Canadian dilbit (tar sands) crude oil as suggested in the comment.

The Oil and Gas Journal article actually supports the analysis and conclusions in the DEIR; that Crude Unit and other modifications would be needed in order for the Refinery to process a substantially heavier crude oil blend. Notably, the proposed project does not include changes in the Refinery Crude Units (called CDUs in the Oil and Gas Journal article). With the exception of the 6,000 bbl/day potential crude oil capacity increase associated with the planned increase in the permit-described fired duty of the DCU H-100 heater that was analyzed in the DEIR, the proposed project does not include project elements that will remove the Refinery crude oil processing constraints (see DEIR Section 2.7) and these issues associated with processing a heavier crude oil blend will not occur.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 4 also describes the sources of crude oils have and will continue to vary with or without the proposed project. The Refinery has processed many heavy crude oils including Cold Lake crude oil mentioned in the Oil and Gas Journal article. Heavy crude oil contaminant issues have been raised in other comments and are addressed in more detail in Response G1-78.172, which explains that contaminant levels, including metals, in many heavy crude oils processed by the Refinery are similar to heavy Canadian dilbit (tar sands) crude oil, Response G1-78.170, which explains the Refinery's use of blending models to predict and avoid incompatible crude oil blends that could result in precipitation of asphaltenes, and Response G1-78.174, which describes TAN limits that control acid in crude oil blends and downstream units.

Comment G1-81.62

Additional emissions from transport, piping, tank loading, and in refinery operations, from volatile diluents used with tar sands crudes have not been identified, and should be, with emissions quantified. Diluents can include volatile and toxic compounds such as BTEX VOCs (Benzene, Toluene, Ethylbenzene, and Xylene).[76] In addition to the highly reactive ozone-precursor quality of such diluents, they need to be identified and evaluated as toxic air contaminants, due to carcinogenicity and other health impacts, as well as any potentially explosive compounds.

A report by Dr. Phyllis Fox on a crude by rail project to the Valero Benicia California refinery identified many impacts due to switches to "advantaged" crude oils, including increased metals, increased use of toxic BTEX compounds, and many other impacts in transportation and at the refinery due to use of changing crude slates.[77] All the issues identified in this report should be evaluated for the Tesoro ND.

G1-81.62

[76] Comments of NRDC on the Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, July 1, 2013, on impacts of diluents and other important impacts related to the Valero Benicia crude by rail project in common with the Phillips 66 Los Angeles refinery complex, http://switchboard.nrdc.org/blogs/dbailey/NRDC%20comments%20letter%20on%20Notice%20of%20Intent%20to%20Adopt%20a%20Mitigated%20Negative%20Declaration%20for%20the%20Valero%20Crude%20by%20Rail%20Project.pdf

[77] Comments on the Initial Study / Mitigated Negative Declaration, Valero Benicia Crude by Rail, June 1, 2013, Dr. Phyllis Fox, http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F93312159 32%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf

Response G1-81.62

The issue of whether emissions from the proposed project were correctly calculated has been raised in other comments, the responses to which contain detailed descriptions of the emissions calculations for the proposed project as further detailed below.

Marine vessel emissions associated with additional crude oil deliveries to accommodate the potential increased capacity of 6,000 bbl/day is addressed in the DEIR (pages 4-26 and 4-27).

Responses G1-78.114 and G1-78.157 address the worst-case emission calculations for the new and replacement storage tanks and associated fugitive components, including pipelines, which were evaluated in the DEIR. VOC emissions for the proposed storage tanks were based on a crude oil vapor pressure approaching the allowable TVP limit by SCAQMD Rule 463 (TVP of 11 psia), and toxics were based on a worst-case hybrid analysis of the toxic content of crude oils currently and potentially processed at the Refinery, including Bakken and Canadian crude oil. Because the Refinery receives only pipeline quality crude oil, diluent is already blended in the heavy Canadian crude oil it receives and is accounted for in the calculations described above.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 4 also explains that the sources of crude oils have varied and will continue to vary with or without the proposed project. Therefore, any changes in crude oil transportation are not a result of the proposed project. Responses to other crude oil property issues are summarized in Response G1-78.94.

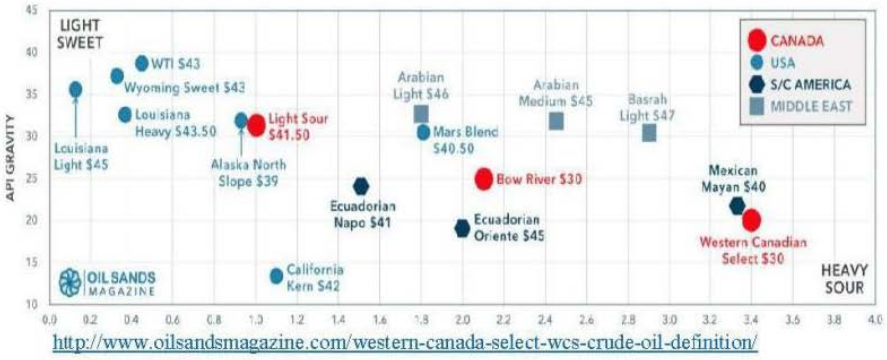
The comment makes reference to impacts identified on a crude oil by rail project to the Valero Benicia California Refinery and claims these impacts should be evaluated for the Tesoro [storage tank] ND. The proposed project does not include crude oil by rail. The Tesoro Storage Tank ND was withdrawn and its project elements included in the DEIR. Therefore, the comment does not apply to the proposed project.

Comment G1-81.63

Tesoro is incentivized to include some amount of Canadian crude in its mix, due to the expected new access through the Tesoro Savage terminal, and due to cost-advantage. This could substantially replace the California heavy crudes. For example, the following chart shows Canadian tar sands crude oil as one of the cheapest:

G1-81.63

Why is Canadian Heavy Oil Cheaper than other Benchmarks? (a snapshot of crude prices)[78]



http://www.oilsandsmagazine.com/western-canada-select-wcs-crude-oil-definition/

G1-81.63 cont'd.

[78] *Crude Oil Vapour Pressure Testing*, January 2012, Vapour pressure testing is an important safety check in the transport, storage and blending of crude oil Hannes Pichler and Klaus Hense, Grabner Instruments, a subsidiary of Ametek, submitted by Ametek Petrolab, http://www.industrycortex.com/datasheets/profile/2921410/article-vapor-pressure-crude-oil-vapor-pressure-testing

Response G1-81.63

The comment claims that Tesoro is incentivized to replace California crude oil with Canadian crude oil. Responses G1-78.178 and G1-78.186 address the fact that the California crude oil production rate has stabilized in recent years, so there is no supply shortage reason to replace California crude oils with other crude oils. Figure 78.178-2 shows that California crude oil is competitively priced compared to other crude oils. Delivered costs, including transportation, must be evaluated in order to compare the costs of various crude oils. Attachment C, the Declaration of Douglas Miller[269], explains the economic advantages for California refineries to process California crude oil. California crude oil is delivered to the Refinery via pipeline, a low delivery cost compared to marine deliveries. Response G1-78.178 demonstrates that California crude oil production has not continued to decline and has remained level in recent years. There is no evidence to support the claim that the Refinery will replace California crude oil with Canadian crude oil, or that the proposed project will enable a switch to Canadian crude oil.

[269] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

Comment G1-81.64

C. Bakken & Canadian Greenhouse Gas emissions were also underestimated

Because the DEIR Project Description does not acknowledge the crude oil slate switch, it failed to evaluate the emissions, including Greenhouse Gases (GHGs) due to this switch. There are at least two components missing. Because of plans to utilize the Tesoro Savage Vancouver Energy Project to transport significant quantities of Bakken crude oil and likely to also bring Canadian tar sands crude, both should be evaluated as new sources causing GHG impacts related to the Project.

The impacts evaluated should not only include impacts from use at the refinery complex, but also the lifecycle emissions from the use of these different crude oils. Such analysis is not only consistent with AQMD policy, but required. In adopting its interim GHG threshold of significance, the AQMD board mandated that *"For the purposes of determining whether or not GHG emissions from affected projects are significant, project emissions will include direct, indirect, and, to the extent information is available,* ***life cycle emissions during construction and operation.***"[79] This is natural, since GHG emissions act on a global scale. They go into the atmosphere and cause climate change globally over a long period of time, and not in a manner that is limited to impacts near the emission sources. The DEIR should evaluate the following:

G1-81.64

[79] SCAQMD Board Approval of Interim GHG Threshold, p. 5, available at http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgboardsynopsis.pdf?sfvrsn=2

Response G1-81.64

Contrary to the comment, as explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 8 describes the Vancouver Energy Project and the potential receipt of crude oil from that project. Master Response 4 also describes that Bakken and heavy Canadian crude oils ("tar sands") have been processed at the Refinery. Thus, analysis of the impacts associated with increased use of any particular type of crude oil is not necessary as it is not a result of the proposed project.

The impacts of shipments received at the Vancouver Energy Project have been analyzed in the Draft EIS for that project.[270] Any shipments of crude oil received from the Vancouver Energy Project will have less GHG emissions from transportation due to the shorter distance for transport than international sources. The proposed project does not increase the Refinery crude oil processing capacity above the 6,000 bbl/day described and analyzed in the DEIR. Therefore, GHG emission reductions would occur should crude oil deliveries shift from international origins to the Vancouver Energy Project.

Additionally, the DEIR does not need to analyze impacts from crude oil production because the proposed project will not cause any changes to that industry.

[270] Draft EIS for the Tesoro Savage Vancouver Energy Distribution Terminal Project available at http://www.efsec.wa gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20PAGE.shtml.

Comment G1-81.65

1. **Bakken crude oil, though lighter, can significantly increase well to wheel GHG emissions due to large methane extraction emissions**

G1-81.65

It is generally assumed that because Bakken crude is lighter, and lower in sulfur, that it requires less energy to refine to produce gasoline and diesel (less cracking, hydrogen production, hydrotreating

However, the use of substantial amounts of Bakken at the refinery means significantly increased methane emissions during extraction. While these drilling / extraction emissions occur outside of California, they emit potent greenhouse gases that contribute to increasing climate change, which does not stop at the borders of the Bakken oil fields -- these impacts are already impacting Los Angeles and the entire planet (including drought, heat waves, etc.).

It has been demonstrated that drilling emissions in the U.S. are higher than previously estimated, including emissions of methane (a greenhouse gas that is 72 times stronger than CO2 over a 20-year period[80]). Generally, the U.S. EPA estimates extraction emissions from the bottom up, based on assumptions about equipment leaks for instance. But a new Harvard study[81] used a top-down approach, to measure actual emissions in the atmosphere. This showed emissions much higher than expected. Other studies that did direct measurement also found higher-than-expected emissions.

G1-81.65 cont'd.

This study, *(A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observations,* Harvard, February 2016), found a major spike in worldwide methane emissions over the last decade, and found the U.S. the likely culprit: "Our results suggest that increasing U.S. anthropogenic methane emissions could account for up to 30–60% of this global increase."

It also found this has coincided with an in oil and gas production increase, and especially an increase in shale gas production ("The U.S. has seen a 20% increase in oil and gas production [US EIA, 2015] and a nine-fold increase in shale gas production from 2002 to 2014") although it did not have enough data to determine the exact U.S. sources.

Discussions of this study described its importance: "There was a huge global spike in one of the most potent greenhouse gases driving climate change over the last decade, and the U.S. may be the biggest culprit, according a new Harvard University study."[82]

Other recent studies also found extremely high levels of methane gas leakage from oil and gas drilling operations. For example, the Science Journal *Nature* reported as follows:[83]

> **Scientists are once again reporting alarmingly high methane emissions from an oil and gas field**, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system. The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study1 suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.
>
> Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.
> "We were expecting to see high methane levels, but I don't think anybody really comprehended the true magnitude of what we would see," says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA's Earth System Research Laboratory in Boulder.

The figure above reported by Nature in the NOAA study topped 9% losses of gas, even higher than the 4% figure found in the 2012 study. The DEIR needs to include analysis regarding the crude oil shift, and the potential for increased emissions that can occur from shale oil extraction in the Bakken region, and particularly compared to ANS crude that is likely to be replaced with Bakken at the refinery.
While in other parts of this report I documented Tesoro's plans to bring Bakken crude through Vancouver Washington to Los Angeles, it should be further noted that Tesoro is also purchasing crude oil storage and transport facilities *within* the Bakken extraction region, specifically to bring to West Coast refineries. Tesoro announced in December of 2015 its plans for *added* capacity to pump 65,000 bpd of crude oil out of the Bakken (N. Dakota region), and to store and transport this crude for West Coast use.[84] (Acquisitions include the 97-mile BakkenLink crude oil pipeline, which connects to several third-party gathering systems, a 28-mile gathering system in the core of the Bakken, "where most of the drilling in today's low price environment is being done," a 154,000 bpd rail loading and a 657,000 bbl storage facility in Fryburg.)

G1-81.65 cont'd.

> ***"We expect our enhanced system to provide Tesoro's West Coast facilities with cost-effective access to advantaged crude oil and provide producers additional market access. . "*** Tesoro spokesperson Brendan Smith said in an emailed statement.

So Tesoro is not only drastically expanding its LA refinery complex and tank storage system to bring new Bakken crude oil through Vancouver Washington, but Tesoro is specifically creating new infrastructure in the Bakken region for pumping additional Bakken crude oil and providing isolated Bakken producers access to Tesoro's market.

The impacts must be identified, as a direct consequence of Tesoro's LARIC Project. As described above, the large U.S. oil boom, identified as a potential reason for the worldwide increase in methane emissions over the last decade, must be evaluated as a direct consequence of this Project. Tesoro's activities in the Bakken, Vancouver, and LA, do not stay in these regions, but have local and global impacts, including impacts in LA due to adding to the burden of climate change, and other impacts.

G1-81.65 cont'd.

[80] California Air Resources Board, Aliso Canyon Natural Gas Leak Preliminary Estimate of Greenhouse Gas Emissions to Date (As of November 20, 2015) *["The global warming impact from methane is 25 times and 72 times that of CO2, for equal amounts by weight, over a 100 year and 20 year timespan, respectively."]* available at: http://www.arb.ca.gov/research/reports/aliso_canyon_natural_gas_leak.pdf

[81] Turner, A. J., D. J. Jacob, J. Benmergui, S. C. Wofsy, J. D. Maasakkers, A. Butz, O. Hasekamp, and S. C. Biraud (2016), A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observations, Geophys. Res. Lett., 43, 2218–2224, doi:10.1002/2016GL067987, available at: file:///C:/Users/Julia%20May/Downloads/Turner_et_al-2016-Geophysical_Research_Letters.pdf Attachment 27

[82] Study Ties U.S. to Spike in Global Methane Emissions, *Published:* Feb 16, 2016, Climate Central, *Researching and reporting the science and impacts of climate change,* http://www.climatecentral.org/news/us-60-percent-of-global-methane-growth-20037

[83] Nature News, 02 January 2013, available at: http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123 , Attachment 28

[84] *Tesoro plans to purchase Bakken pipeline, storage,* Jessica Holdman, Bismarck Tribune, Dec 17, 2015, http://tsocorp.com/customers-and-suppliers/wholesale/terminals/ , Attachment 29

Response G1-81.65

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 4 also explains that sources of crude oils have varied, and will continue to vary, with or without the proposed project. It should be noted that currently 80 to 90 percent of crude oil processed by the Refinery is delivered by marine vessel. As described in Response G1-81.63, California crude oils that are delivered to the Refinery via pipeline are cheaper and the supply relatively constant, so the amount of crude oil delivered via marine vessel is not expected to change. The proposed project will improve efficiency and benefit any crude oil delivery by marine vessel. Thus, analysis of the impacts associated with increased use of any particular type of crude oil is not necessary as it is not a result of the proposed project.

Additionally, the DEIR does not need to analyze impacts from crude oil production because the proposed project will not cause any changes to that industry. The comment urges an analysis of the impacts from sourcing Bakken crude oil from the Midwest. However, to focus an analysis of the impacts of producing a particular crude oil (e.g., Bakken) is not necessary because the proposed project does not change the sourcing of crude oils to be blended and processed at the Refinery and, as explained above, the crude oils purchased at any given time change. Therefore, an analysis of a single crude oil would not provide useful or accurate information related to the impacts of the proposed project.

The DEIR appropriately included emissions from direct and indirect sources (see Sections 4.1.1 and 4.1.2 of the DEIR) associated with the proposed project. Therefore, contrary to the comment, the proposed project accurately accounts for emissions which may result from the proposed project.

As detailed in responses listed in Table 78-94.1, Bakken and heavy Canadian crude oils are similar to other light and heavy crude oils currently processed by the Refinery. As described in Master Response 4 and Response G1-78.150, in the future, as now, any Bakken or heavy Canadian crude oils processed would have to be combined with other crude oils to create a crude oil blend that matches the Refinery's processing capabilities and permit limitations. This is what has occurred with the small amounts of Bakken, heavy Canadian, and many other heavy and light crude oils that were utilized in the baseline period, and is what will continue after the construction of the proposed project. Any increased use of Bakken or heavy Canadian crude oils, or any other specific crude oils, would not be caused by the proposed project. Moreover, the proposed project's storage tank and fugitive emission impacts were analyzed in detail using the worst-case assumptions (e.g., the maximum vapor pressure of crude oil allowable by SCAQMD rules), which would account for any impacts from increased use of Bakken or heavy Canadian crude oil.

Tesoro is a refining and marketing company that does not own or invest in crude oil production fields. Tesoro owns infrastructure and facilities to transfer and process crude oil produced by

others. The statement made in December 2015 by Brendan Smith refers to the infrastructure to transport Bakken crude oil, not to produce crude oil.

It should be noted that Tesoro owns two refineries (the Mandan and Dickinson Refineries) in the Bakken region that process primarily Bakken crude oil. Statements made by Tesoro regarding sourcing "advantaged crude oils", including Bakken crude oil, are typically made with regard to its West Coast system, which includes the Kenai Refinery in Alaska, the Anacortes Refinery in Washington, and the two California refineries in Martinez and Los Angeles[271], not specifically the Los Angeles Refinery. As explained in Response G1-78.94, it is correct to say that Tesoro makes ongoing efforts to provide "advantaged crude oil", as that term is used by Tesoro (i.e., any economically advantaged crude oil capable of being processed at each of Tesoro's refineries). Providing "advantaged crude oil" to Tesoro refineries, including the Los Angeles Refinery, is occurring, and will continue to occur, with or without the proposed project. Additionally, Responses G1-81.22 through G1-81.24 explain numerous corporate statements made by Tesoro that, when put in proper context, do not support claims that the proposed project is dependent on processing any particular type of crude oil. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery.

Further, the comment claims, without providing substantial evidence, that the U.S. oil boom, identified as a potential reason for the worldwide increase in methane emissions over the last decade, should be evaluated as a direct consequence of the proposed project. The sourcing of crude oil is a complex process explained in the Declaration of Douglas Miller (see Attachment C) and is not affected by the proposed project. Therefore, the proposed project will not cause imports of any particular crude oil and will not change the emissions associated with crude oil production.

As explained in Master Response 7, the proposed project is not an expansion of the Refinery. An objective of the proposed project is to make Refinery process modifications that improve operating efficiency through integration and enable the shutdown of the Wilmington Operations FCCU while maintaining the overall production capability of transportation fuels providing substantial emission reductions on-site and reducing carbon intensity (see Section 2.2 of the DEIR). See Master Response 8 regarding the Vancouver Energy Project and potential crude oil deliveries from the Vancouver Energy Project.

The GHG emissions from the proposed project were analyzed and presented in Section 5.2.2 of the FEIR. It should be noted that there is an error in Table 5.2-7 where the GHG emissions for

[271] The reference to the "West Coast system" that appears in Tesoro's corporate presentations and statements is a term that is used with varying meanings based on the context of the presentation or statement. Analyst day and earning statements presentations are given to an audience that routinely participates in the presentations and is familiar with Tesoro's corporate structure and financial performance. Therefore, some of the references are not intended to be as explicit as they would be to an uninformed audience. At times, the term refers to Tesoro's four west coast refineries, but it can also refer to those four refineries as well as Tesoro Logistics or a distribution system to third-party clients on the west coast. Thus, the context surrounding the use of this phrase is always necessary to understand the speaker's intended meaning, but the phrase is not used to refer only to the Los Angeles Refinery in isolation.

the Watson Cogen Facility have been reported as 22,208 metric tons per year. This number is actually 22,208 short tons per year and the correct number for the table is 20,147 metric tons per year (see FEIR Appendix B-3 Table 17 on page B-3-49). The Watson Cogen GHG emission estimates in Table 5.2-7 and the subsequent indirect GHG emission increases in Table 5.2-8 have been revised in the FEIR (GHG emission reduction of 68,250 metric tons per year). In the DEIR, local GHG emission reductions are expected with AB 32 compliance resulting in no change to the GHG pool of allowances in the GHG Cap and Trade Program. Therefore, no significant impacts to GHG emissions were identified.

Lifecycle ("well to wheel") GHG impacts resulting from the extraction and transport of Bakken crude oil is beyond the scope of the DEIR. The DEIR accounts for direct GHG emissions associated with stationary sources, the transport of LPG by rail and material transport by truck within the State of California (see Table 5.2-6 of the DEIR) and GHG emissions associated with indirect sources including stationary sources and increased utilities (see Table 5.2-7 of the DEIR), as required by CEQA Guidelines § 15358. On December 5, 2008, the SCAQMD Governing Board adopted the staff proposal for an interim GHG significance threshold for projects where the SCAQMD is lead agency. While the lifecycle emissions are to be considered "to the extent information is available,"[272] predicting the GHG emissions from the sources of crude oil purchased by Tesoro is not reasonably achievable because the source of crude oil varies widely as shown in Master Response 4 Table G0-2.4-1. Moreover, the decisions with respect to sourcing the crude oil slate are made independent of the proposed project. In December 2009, the California Natural Resources Agency removed the term "lifecycle" from the CEQA Guidelines Appendix F guidance on analysis and mitigation of energy impacts from proposed projects in conjunction with its rulemaking pertaining to analysis and mitigation of GHG impacts.[273] Therefore, "well to wheel" impacts need not be analyzed.

[272] SCAQMD Board Letter, Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans, December 8, 2008, http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgboardsynopsis.pdf?sfvrsn=2.

[273] California Natural Resources Agency, 2009. Final Statement of Reasons for Regulatory Action for the Amendments to the State CEQA Guidelines Addressing Analysis and Mitigation of Greenhouse Gases Emissions Pursuant to SB97, December 2009, http://resources.ca.gov/ceqa/docs/Final_Statement_of_Reasons.pdf.

Comment G1-81.66

2. Importing additional extremely heavy, high sulfur Canadian Tar Sands crude oil could significantly increase GHG emissions

Although Tesoro's main strategy is importing Bakken crude oil, as previously discussed, Tesoro will also have access to significantly increased levels of Canadian tar sands crude through the Tesoro Savage Vancouver project. If this Canadian crude replaces a crude at the Tesoro refinery average shown in the previous estimation of about 1.5% sulfur, the Canadian crude would increase the percent sulfur up to 3.5 or more percent sulfur for that number of barrels. This would introduce a larger mass of sulfur into the refinery compared the past baseline (and would increase the hazardous hydrogen sulfide in the refinery).

It would also increase the desulfurization processing needed, the processing in the Sulfur Recovery Unit, and the energy use and resultant emissions of those processes. Increased energy equates to higher GHG emissions. Since the average sulfur content of crude oil in the refinery is nowhere near 3.5%, introduction of tar sands crude in significant quantities would have to increase the sulfur percent unless other reduction measures to reduce intake of the average sulfur in other crudes was taken. So GHGs would also have to increase due to the energy needed to remove this additional sulfur. This example shows why a specific crude oil sulfur baseline is needed, and the potential for that baseline to change, because this impacts the amount of desulfurization downstream.

If the newly introduced Canadian crude volumes replaces a crude at the refinery average API gravity of 29 degrees previously estimated, with a heavier Canadian crude (for example WCS) with API 20.3,[85] this would significantly increase the gravity from a moderate to a heavy crude (since API gravity is a reverse scale, so that lower numbers equals higher gravity). This would require additional cracking and coking to accommodate the crude, and require heated tank storage with mixing equipment.

As above, this increased activity means increased energy use, which equates to higher GHG emissions for that portion of the crude replacement, unless efforts were taken to offset this increased gravity (higher carbon content) by lowering the average of other crudes introduced. This example shows why a specific API gravity baseline is needed for the refinery, because it impacts energy use downstream.

Even if Tesoro replaced/s some of its use of California heavy, high sulfur crude with Canadian crude, this could still increase the refinery sulfur average and heaviness, since Canadian crude is one of the most extreme crudes oils by both counts.

G1-81.66 cont'd.

While the refinery can also mix crudes to get an average similar to the existing refinery previously described (replacing ANS with a mix of Canadian and Bakken), that does not necessarily mean there will be no impacts because crude oils have other qualities, such as TAN, benzene, paraffin content, etc., which affects the energy use at the refinery. For all these reasons, it is necessary to provide a baseline of specific crude oils used, and a specific baseline of Canadian crudes used, projected use in the future, and to evaluate how this would affect storage tanks, cracking, coking distillation, heaters, boilers, desulfurization, sulfur recovery, etc.

G1-81.66 cont'd.

[85] *Id, The North American Crude Boom, Platts, at Slide 21*

Response G1-81.66

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 4 also explains that the

sources of crude oils processed by the Refinery have, varied, and will continue to vary with or without the proposed project.

As explained in Response G1-81.65, heavy Canadian crude oil has been blended and processed in limited quantities at the Refinery. An increase in sulfur content of the crude oil blend cannot be accommodated at the Refinery without modifications to the Sulfur Recovery Plants (SRPs) as discussed in Section 2.5.4.1 of the DEIR (see also Master Response 4). While it is true that to process a higher sulfur content crude oil additional sulfur recovery capacity is required, as discussed in Master Response 4, the Refinery operates near capacity in the existing SRPs and the proposed project does not modify the SRP capacity. Therefore, the Refinery is restricted to the current operating envelope and must maintain the crude oil blend currently processed at the Refinery. Furthermore, without an increase in SRP capacity, no corresponding increase in GHG emissions from increased energy use is anticipated, as claimed in the comment. As explained in G1-81.65, the GHG emission impacts were analyzed for the proposed project and were determined to be less than significant.

The same limitation (i.e., the Refinery operates near the DCUs operating capacities) occurs relative to coke processing. As described in Section 2.5.4.1 on pages 2-14 and 2-19 of the DEIR, the Carson and Wilmington Operations DCUs are limited on the allowable amount of residual oil feed, metals, and sulfur content in the crude oil blend processed by the Refinery in order to stay within DCU operating constraints and for the coke product to meet quality specifications. The Refinery already operates near these limits (see page 2-18 of the DEIR), so there is no room for more heavy crude oils than are currently processed.

As explained in Response G1-78.150, the blending of Bakken and heavy Canadian crude oils cannot replace ANS. The import of Bakken and heavy Canadian crude oil would require blending with other crude oils, to meet the specifications of ANS and to process the crude oil through the Refinery. The Refinery uses blending databases and models to ensure the blend of crude oils to be processed meets the Refinery operating envelope specifications.

Comment G1-81.67

Crude oil extracted from Canadian tar sand pits, like this one, release more carbon emissions than crude from U.S. sources. (from UC Davis news, cited below)

Energy use from well to wheels (from the strip mining extraction, transport, refining, and use the fuels produced) for Canadian Tar Sands is one of the worst energy users. Overall, introduction of Canadian tar sands crude oil was found in a 2015 study to cause about 20% more GHGs than domestic crude oils:[86]

> Gasoline and diesel fuel extracted and refined from Canadian oil sands will release about 20 percent more carbon into the atmosphere over the oil's lifetime than fuel from conventional crude sources in the United States, according to a study by the U.S. Department of Energy's Argonne National Laboratory; the University of California, Davis; and Stanford University.

Almost any amount of this crude introduced by Tesoro could have a significant impact, and should be tracked. A 20% increase in emissions at the refinery for the portion of fuels produced due to import of Canadian tar sands crude could easily exceed AQMD thresholds of significance, and should be evaluated in the DEIR.

[86] Emissions from Canada's oil-sand crude higher than those from U.S. sources, Kat Kerlin on June 25, 2015, published in UC Davis news at: https://www.ucdavis.edu/news/emissions-canadas-oil-sand-crude-higher-those-us-sources, Attachment 30

G1-81.67

G1-81.67 cont'd.

Response G1-81.67

As explained in Response G1-81.65, Tesoro is a refining and marketing company that does not own or invest in crude oil production fields and the proposed project will not result in changes to oil production operations. The independent GHG emissions associated with oil production are regulated and accounted for, but these environmental impacts are unrelated to the proposed project. GHG emissions produced by combusting the fuels produced by the Refinery are included in the AB32 GHG Cap and Trade Program. As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil

blend. The Refinery does not process unblended heavy Canadian crude oils, so no increase in emissions associated with processing unblended heavy Canadian crude oils would occur from implementing the proposed project.

Comment G1-81.68

V. Other emissions and environmental impacts are missing from the DEIR

Missing Project emissions or missing evaluation in summary below need to be corrected in the DEIR, and are discussed further in this section:

- **Flares and Pressure Relief Devices:** A dozen new connections of equipment to Pressure Relief Devices and flares were counted with zero potential to emit, based on the flare capacity to handle these gases, but this approach failed to evaluate the potential to emit during shutdowns and other upsets when these added volumes of gases have no place to go but to be burned in the flare and emitted as pollutants;
- **Heaters and Boilers:** The heat input for DCU Heater H-100 was increased 20%, but criteria pollutant emissions were counted as lowered.
- **42-inch pipeline expansion from marine terminals** to new storage tanks described in the 2014 Negative Declaration disappeared from discussion in the DEIR, despite a description that some down-pipe sections within the refinery will expand.
- **FCCU:** The FCCU shutdown was identified by the State of California as part of the environmental conditions of approval for Tesoro's purchase of BP, and should not receive pollution credits.
- **Earthquake fire and other risks:** Especially given the high earthquake and related hazards, and high probability of major earthquakes during the Project lifetime, special attention is needed to fully evaluate these major risks that are increased due to the Project.

G1-81.68

Response G1-81.68

The issues raised in the comment are addressed in more detail in subsequent comments and are responded to in detail in subsequent responses as noted in Table 81.68-1.

Table 81.68-1

Topics Raised in Comments and Location of Responses

Topic	Response	
	Master Response Number	Specific Response Number
Flares	15	G1-81.69 through G1-81.78
Heaters and Boilers	12	G1-81.79 through G1-81.88
Marine Terminal Pipeline	-	G1-81.89 through G1-81.91
FCCU	13	G1-81.92
Hazards	9	G1-81.94

Note: - = No Master Response prepared on this topic.

Comment G1-81.69

A. Flaring emissions are already large; new pressure relief connections to flares will increase emissions but were counted as zero, despite permits directing burning gases in flares

1. Tesoro existing flare baseline emissions are already large

Oil refinery flares are major emissions sources in the LA Basin, emitting many thousands of pounds per year, and regularly thousands of pounds in one day, including emissions of SOx, VOCs, NOx, CO, and PM2.5/PM10. Flares are designed to burn gases when malfunctions occur that require that process vessels must shut down, or during smaller process upsets, and during planned shutdowns. This is in order to avoid dumping dangerous gases *directly* to atmosphere, however, the U.S. EPA and the AQMD found many ways to minimize and entirely prevent flaring, and set regulations requiring this (including compressing and recycling gases, and preventing repeat malfunctions).

G1-81.69

AQMD regulations require that flaring be minimized, and flaring emissions have gone down substantially compared to before the control regulation was adopted. However, major flare events emitting thousands of pounds of pollutants are still very common in the South Coast District. The AQMD described flares as follows in its Final Staff Report on Rule 1118.[87]

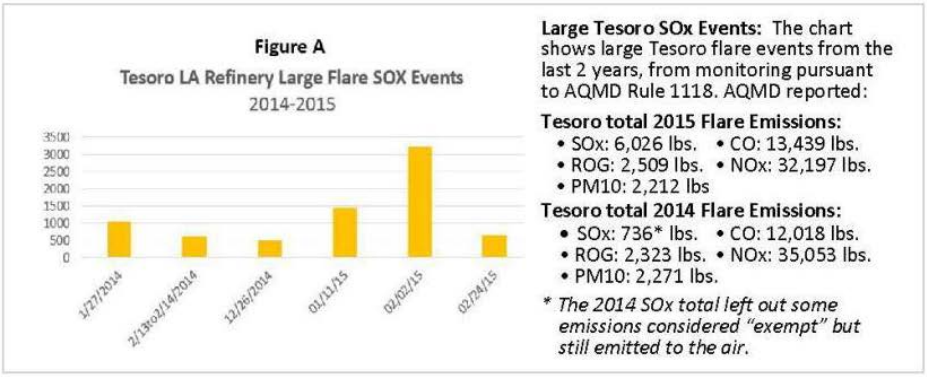
> At petroleum refineries, flares have historically been used to dispose of combustible gases resulting from emergency relief, overpressure, process upsets, startups, shutdowns and other operational and safety reasons to prevent direct release of toxic and /or odorous substances to the atmosphere. In recent years, U.S. Occupational Safety and Health Administration (OSHA) and U.S. EPA have become more concerned with refinery operation, resulting in tighter regulations on safety and emissions control and enforcement actions such as Consent Decrees, as shown before. **Furthermore, smoke, noise, glare and odors sometimes associated with refinery operations may, and at times have impacted the surrounding communities,** leading to an increase in the involvement of community and environmental groups in the regulatory process of controlling refinery flares. (emphasis added)

3-9-2010 Tesoro Power Outage caused Flaring, billowing smoke, neighbors reported explosions told hearing explosions, AQMD reported to CBE they had no equipment for air samples that night

G1-81.69 cont'd.

Tesoro LA is no exception, as shown in the flaring photo above, and in the 2014 and 2015 Tesoro flaring emissions of over a thousand pounds per day, charted below. Note that the size of the largest events increased from 2014 to 2015. The chart does not include many smaller events, or continuous flare emissions from pilot and purge gases, but annual totals are shown to the right of the chart. Flare data used to produce this chart was provided to CBE on 5/13/2016 by the AQMD, attached.[88] Total annual emissions are available on the AQMD website.[89] The AQMD data also

showed events with large CO emissions, for example 1450 lbs. (2/4/15), and 1172 lbs. (2/2/15), in addition to at least 100 lbs. each of PM10, ROG (VOCs), and NOx on these dates and others.



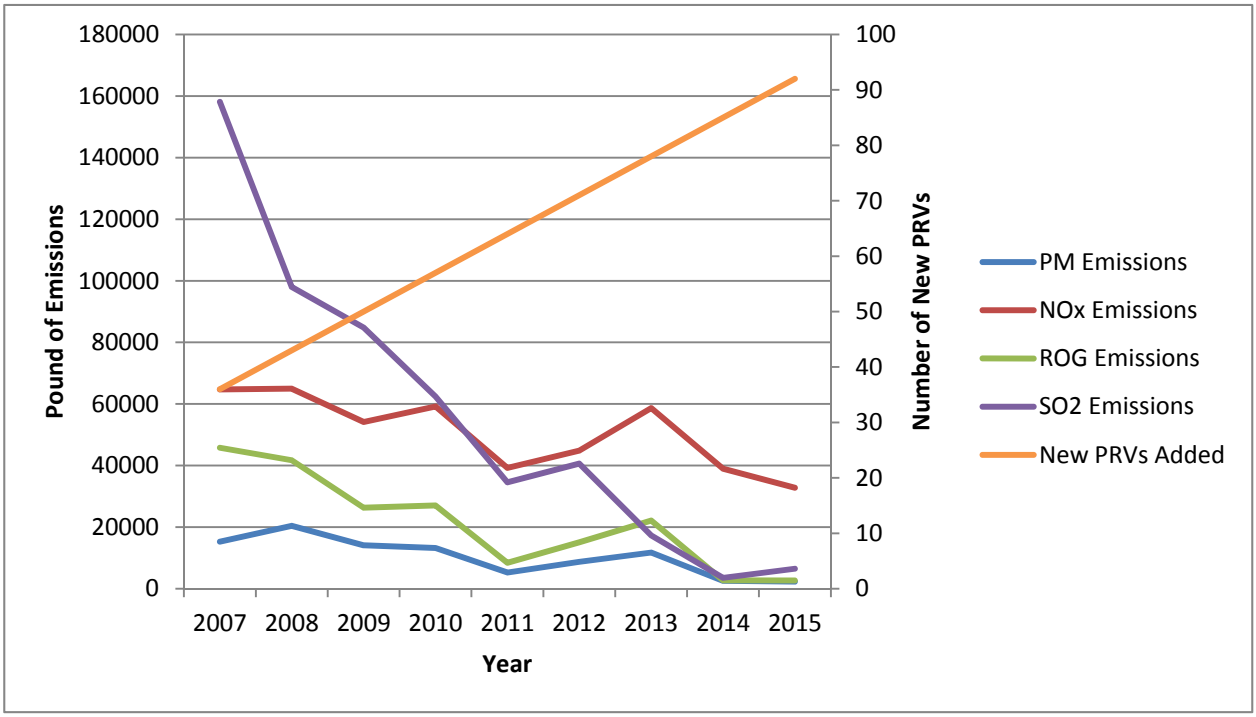
G1-81.69 cont'd.

[87] Final Staff report for Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares, October 2005, at p. II-1, available at http://www.aqmd.gov/docs/default-source/compliance/rule-1118/rule-1118-staff-report.pdf?sfvrsn=2
[88] Attachment31: R1118EVENTDATAFORM_2015Q1, Attachment 32: LAR_R1118_REPORT_4Q14_SCAQMD, Attachment 33: LAR_R1118_REPORT_1Q14_SCAQMD
[89] Total Tesoro flare emissions available at SCAQMD website: Tesoro Carson Refinery (formerly BP Carson) 2015 Rule 1118 Quarterly Flare Emissions: http://www.aqmd.gov/docs/default-source/compliance/rule-1118/refineries/tesoro-refinery-carson/2015-tesoro-carson-flare-data-(formerly-bp-carson).pdf?sfvrsn=12 , and Tesoro Refinery Carson (formerly BP Carson) 2014 Rule 1118 Quarterly Flare Emissions: file:///C:/Users/Julia%20May/Desktop/jan12%20to%20Apr16%20NEW/refineries%20Tesoro/Tesoro%20BP%202016%20integration%20DEIR/background%20info/2014-tesoro-refinery-carson-flare-data.pdf , Attachments 34 and 35

Response G1-81.69

The comment provides information on existing baseline flaring emissions. No specific comments on the DEIR are made. Master Response 15 provides historical hours and flowrate from flaring, which show historical decreases. Figure A of the comment shows the variability in flaring events. However, as described in Response G1-78.207 and shown in Figure 81.69-1, overall flaring has decreased dramatically since revisions to SCAQMD Rule 1118 were implemented.

While not explained in the body of the comment, the title to the comment mentions the addition of pressure relief valve (PRV, also called pressure relief device (PRD) or pressure safety valve (PSV)) connections to the flare. As described in Response G1-78.207, increasing connections to the flare gas recovery system does not equate to an increase in flaring emissions. Figure 81.69-1 shows that even with increased pressure relief connections added to the flare gas recovery system, flaring emissions have been reduced.



Source: Emissions data: http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-refinery-carson, years 2007 -2015
http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-wilmington, years 2007 -2015
http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-sulfur-recovery-plant, years 2007 -2014
PRV data: Tesoro permit applications

Figure 81.69-1

Historical Number of PRVs Added to the Flare Gas Recovery System and Historical Flaring Emissions for the Tesoro Los Angeles Refinery (2007-2015)

Comment G1-81.70

2. The Project adds a dozen new vents to the flare, with large potential emissions

The DEIR should provide flare baseline emissions and identify a realistic flare Potential to Emit far above zero, due to the many new connections of air pollution sources to the flares. A Potential to Emit of zero given in the DEIR is not possible, since refineries must at the least vent through flares during planned shutdowns, where the gases have nowhere to go but to the flare (they will no longer be contained inside the refinery). Although some refineries have identified the possibility of new innovations to store some gases within vessels even after shutdown, this involves increasing the pressure rating of these vessels through physical modification or new construction. No such proposal was provided in the Tesoro LARIC Project.

In addition to planned shutdowns, it is much more likely that there will also be many unplanned shutdowns and upset conditions sending both large and small volumes of hydrocarbon and sulfur-laden gases to the flares, as is currently the case, born out by the AQMD flare data provided to us.[90] When refinery gases are flared, they emit criteria pollutants. Instead, the DEIR allowed the use of the Tesoro assumption that flare events will never happen. This is worse than unrealistic – it grossly underestimates the Potential to Emit in flares.

G1-81.70

[90] The full AMQD flare monitoring data for Tesoro makes up almost 70 separate spreadsheets and so is not reproduced here – only the monitoring data charted in Figure A above is attached.

Response G1-81.70

The comment raises the same issues as that raised in Comment G1-78.207. As described in Master Response 15 and Response G1-78.207, connecting PRVs to the flare gas recovery system do not correlate to increases in flare emissions. Flares are primarily used as safety devices to combust process gases generated during process unit upsets that exceed the capacity of the flare gas recovery system. Emergency flaring events are unexpected, unplanned events and the emissions from emergency flaring events are not foreseeable and, as such, quantifying the emissions would be speculative.

The SCAQMD Engineering evaluations concluded that flaring emissions are not expected to increase as a result of the proposed project (see SCAQMD Engineering Evaluations AN575839 page 79, AN575840 page 77, and AN575841 page 75). As the comment states, flaring from process upsets and shutdowns occur today. Planned shutdowns do not vent through PRVs, but instead are vented through process valves. Therefore, the addition of PRVs to the unit has no effect on planned unit shutdowns. The proposed project assumes that flaring will occur, but that flaring will not increase over existing conditions.

Comment G1-81.71

Data provided available in the draft Title V engineering calculations show a very large Potential-to-Emit VOCs (many thousands of pounds per hour) from new Project components. G1-81.71

For example, the table below from the draft Title V permit show "General Common Release Scenarios" for Tesoro's No. 5 Flare. It states:[91]

> **"The PSVs tied into the No. 5 Flare have multiple relieving cases,** either in unique relief or as part of a common relief scenario. Common release scenarios, which impact flare size, are described in the table below."

No. 5 Flare General Common Release Scenarios

Common Release Scenarios	Lbs/hr	MW	Flare Tip Mach No.
Total Refinery Power Failure	1,450,000	35	0.57
Refinery Cooling Water Failure (No. 8 Cooling Tower Failure)	364,005	30	0.15
Polypropylene Plant Power Failure	886,835	38	0.32
Fire (largest fire circle release – Unit 7600 Fire Circle A)	479,170	42	0.16

The quote and list shows new PSVs (Pressure Safety Valves, also called Pressure Relief Devices (PRDs)) vented for example to Flare No. 5. This example shows from 364,005 to 1,450,000 lbs/hr of gases that can release to this one flare. Since flares are specifically made to burn hydrocarbon gases during refinery shutdowns and upset conditions (in order to avoid dumping these gases directly to the atmosphere through the PRDs), we know that the lbs/hr above include significant percentages of hydrocarbons, and many streams include high concentrations of sulfur compounds. G1-81.71 cont'd.

[91] Draft Title V Permit, p. 62 (147th p. of pdf)

Response G1-81.71

The reference for the flare scenarios shown in the comment are not from the draft Title V permit as stated in the comment. The data presented are included on page 62 of the February 24, 2016 engineering evaluation of the permit application (AN 575839) for the No 5 Flare System for the purpose of evaluating if a modification to the flare capacity (i.e., size) is required in order to connect additional PRVs to the flare gas recovery system. The SCAQMD engineering analysis determined that no modification to the flare capacity is needed to accommodate the additional PRV connections. As explained in Response G1-81.69, the new PRV connections to the flare gas recovery system do not equate to an increase in flaring. The data presented in the comment Table 5 are design flare vent gas capacities to maintain safe and reliable operation of the flare. All refinery projects that include new PRV connections to any flare are evaluated by SCAQMD permitting staff to ensure that the potential new PRV relief loads (maximum vent gas capacities) are within the flare tip design parameters. The mass emission rate (lb/hr) values do not represent potential releases from the proposed project; rather they are flare design release scenarios. As explained in Master Response 15, emergency flaring emissions vary widely in volume and composition depending on the type and location of the upset and predicting an upset release would be speculative.

Comment G1-81.72

The lbs/hr figures above refer to the gases *sent* to the flare system, not what is *emitted* by the flare after combustion. To determine the emissions out of the flare, a certain VOC destruction efficiency is assumed. The SCAQMD does not set a specific hydrocarbon combustion or destruction efficiency in its refinery flare control regulation, but the Bay Area Air Quality Management District (BAAQMD) does in its refinery flare monitoring regulation (98% for most cases, and 93% for low-BTU gases).[92] At 98%, this means only 2% of hydrocarbons remain after burning in the flare. (The rest comes out mainly as the greenhouse gas CO2).

Using 98% destruction efficiency (and assuming these gases are 100% hydrocarbon) results in the following Potential to Emit for each of these scenarios:

- 29,000 lbs/hr of hydrocarbons (ROG or VOCs) - Total Power Failure, (2% of 1,450,000)
- 7,280 lbs/hr during a Cooling Tower failure, (2% of 364,005)

G1-81.72

- 17,737 lbs/hr during a Polypropylene Plant power failure, (2% of 886,835) and
- 9,583 lbs/hr during a fire. (2% of 479,170)

If the gas volumes routed to the flare contain a smaller percentage of hydrocarbons (not 100%, but for example, 30%), then emissions would still be thousands of pounds per hour after burning in the flare:

- 8,700 lbs/hr of hydrocarbons (ROG or VOCs) - Total Power Failure,
- 2,184 lbs/hr during a Cooling Tower failure,
- 5,321 lbs/hr during a Polypropylene Plant power failure, and
- 2,875 lbs/hr during a fire.

In fact, flare combustion efficiency can go far below 98%[93] (down to 70%[94] or even lower), which would mean that emissions of VOCs would go far *higher* than in the examples above. For example, even with efficiency as high as 90%, 10% of the VOCs would remain uncombusted and be emitted, so emissions above would be five times higher than when only 2% remains. And at 70% destruction (with 30% VOCs remaining), emissions would be 15 times higher than when 2% remains. Importantly, a study in Houston found that flaring emissions combustion could go down, and that this and other variability (could result in significant increases in ozone formation in the region. [95]

The DEIR needs to provide more information characterizing the percent of hydrocarbons and sulfur compounds present in the vessels that would vent through new PRDs to the flares, and provide a full emissions analysis now completely missing. Instead, the assumption of zero emissions is conclusory and without a basis.

G1-81.72 cont'd.

[94] BAAQMD, Miscellaneous Standards of Performance, Rule 11, Flare Monitoring at Petroleum Refineries, Rule 12-11-401 Flare Data Reporting Requirements, section 401.9: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1118.pdf?sfvrsn=4 [*"For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of emission calculations only, a flare control efficiency of 98 percent shall be used for hydrocarbon flares, and a flare control efficiency of 93 percent shall be used for flexi-gas flares or if, based on the composition analysis specified in Section 12-11-502, the calculated lower heating value of the vent gas is less than 300 British Thermal Units/Standard Cubic Foot (BTU/SCF)."*]

[93] For example, Dow Chemical, McCready, 2001, *Industrial Flares, Linking Plume Dispersion with Combustion,* Attachment 36

[94] *Theoretical and observational assessments of flare efficiencies,* Leahey, J Air Waste Manag Assoc. 2001 Dec; 51(12):1610-6. Available at: http://www.ncbi.nlm.nih.gov/pubmed/15666465 Attachment 37

[95] Web publication April 05, 2012, *Impacts of Emission Variability and Flare Combustion Efficiency on Ozone Formation in the Houston–Galveston–Brazoria Area,* Pavlovic et al, Center for Energy and Environmental Resources, The University of Texas at Austin, *Ind. Eng. Chem. Res.*, 2012, *51* (39), pp 12593–12599, DOI: 10.1021/ie203052w, Abstract: *["**Recent studies in the Houston–Galveston–Brazoria (HGB) area of Texas have suggested that industrial flares exhibit high temporal emissions variability and that flare combustion efficiencies could vary with air and steam assist rates, particularly at lower flow rates, and when low heating value gases are combusted.** This work examined the difference in ozone formation potential associated with accounting for temporal variability in flaring emissions, as opposed to assuming the same amount of mass was emitted at a constant, average flow rate. The temporal variability in flare emissions was found to lead to differences in ozone concentrations of as much as 27 ppb in the HGB area. This work also examined the potential ozone formation impacts of flare combustion efficiencies of less than 98–99%, applied to 25 flares throughout the HGB region. **Deterioration in combustion efficiency (CE) was found to affect ozone concentrations by a few to more than 50 ppb, depending on the level of the assumed CE.** While the ozone impacts associated with temporal variability in emissions typically lasted a few hours, consistent with the length of large flaring events, lowering of the CE significantly increased emissions and ozone concentrations over periods ranging from several hours to several days for some flare types. Thus, changes in CE may affect ozone concentrations for longer durations and over larger spatial extents than episodic emissions events."*], available at: http://pubs.acs.org/doi/abs/10.1021/ie203052w?src=recsys&journalCode=iecred , Attachment 38

Response G1-81.72

As explained in Response G1-81.71, the data for the emission releases are part of the evaluation of the adequacy of the maximum capacity of the flare. They do not represent a typical release from and, therefore, are not an appropriate foundation for emission calculations from the proposed project.

Emissions from flares are restricted by SCAQMD Rule 1118 to prohibit combusting vent gases except during emergencies, shutdowns, startups, turnarounds or essential operational needs. SCAQMD Rule 1118 is prescriptive in the calculation methodology for emissions from flares.

The emissions from a flaring event are based on data collected from required monitoring equipment including flowrate, higher heating value, and sulfur content of the vent stream. SCAQMD Rule 1118 provides emission factors for calculating emissions from flaring events based on monitored data and in the event of monitoring equipment failure. The prescriptive nature of SCAQMD Rule 1118 accounts for variations in the release scenarios that can precipitate a flaring event.

As the comment states, flaring from upsets and shutdowns occur today. The proposed project does not change flaring or flare emissions by adding PRVs (see SCAQMD Engineering Evaluations AN575839 page 79, AN575840 page 77, and AN575841 page 75). As explained in Response G1-81.69 and in more detail in Response G1-78.207, the mere addition of PRVs to a flare gas recovery system is not indicative of an increase in flaring events or emissions. PRVs are safety devices, which are normally closed and do not create an increase in total flow from a unit. Additional PRVs allow the existing unit to depressurize from more locations within the unit, but the volume of material in the unit that would need to be vented would be the same. The composition of a potential process upset is unknown, so to calculate emissions from an unknown composition and flow rate would be speculative. Therefore, the DEIR appropriately included only the fugitive emissions associated with the new PRVs in the impacts analysis in Chapter 4 and Appendix B-3.

Comment G1-81.73

Sulfur compounds are emitted differently by flares compared to hydrocarbons – they are not destroyed in the flare, but instead transformed to other sulfur compounds. For example, most of the H2S turns into Sulfur Oxides. In other words, all the sulfur going to the flare is emitted as a sulfur compound, generally in the form of SOx. The amount of SOx emitted depends on the percent of sulfur compounds in the gases sent to the flare. The DEIR should identify the percent of sulfur compounds present in gases that would be vented through the new PRDs to the flares.
Sulfur oxides emitted by flares are less deadly than H2S entering the flare, but SOx (such as SO2) are still very hazardous pollutants even during short exposures. U.S. EPA states:[96]

> **Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms.** These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing.) . . . SOx can react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.

The Title V permit provided another list of pounds per hour potential to emit from PSVs to the flare below, including 5 new PSVs connected to the Naphtha Hydrodesulfurization Unit. This process has high concentrations of sulfur, because the purpose of hydrodesulfurization is to remove sulfur contamination from hydrocarbons. It also shows five new PSVs for the new LPG rail loading / unloading rack. This should be a lower sulfur, but with significant hydrocarbons (VOCs). Using the BAAQMD 98% destruction efficiency of VOCs in the relief loads would result in each of the connections having the flare emissions listed below showing two cases (100% VOCs in PRV vent gas, and 30% VOC in vent gas). This does not show higher emissions that would occur from multiple flares relieving at once (a common occurrence), or SOx and other criteria pollutants.

G1-81.73

G1-81.73 cont'd

Table 7: Potential flare emission increases are substantial

Flare Connection /PSV#	Relief Load[97] (lbs/hr)	**1)** 98% destruction of VOCs in flare (assuming vent gas is 100% VOC), lbs/hr	**2)** 98% destruction of VOCs, at 30% VOC in vent gas, lbs/hr
Naphtha Hydro-desulfurization Unit			
1/ 44PSV-5045	113,611	2,272	682
2/ 44PSV-5046	19,903	398	119
3/ 44PSV-5043	53,735	1,075	322
4/ 44PSV-5042	38,252	765	230
5/ 44PSV-5051	14,577	292	87
LPG Railcar Loading/Unloading Rack			
6/ 74PSV-5007	6,665	133	40
7/ 74PSV-5008	3,998 or 11,729*	80 or 235	24 or 70
8/ 74PSV-5009	44,564	891	267
9/ 74PSV-5013	119	2	0.7
10/ 74PSV-5108	9,590	192	58
Alkylation Unit			
11/ 76PSV-5008	147	3	0.9
12/ 76PSV-5009	116	2	0.7

* This device was given two different emissions scenarios, dependent on cause of the release.

Instead of calculating potential to emit, the Title V document which provided the basis for the DEIR referred to assumptions in a Tesoro study, identified as an Attachment #6. Attachment #6 did not quantify potential flare emissions, instead it evaluated whether common relief scenarios of the PSVs vented volumes of gases large enough to require a larger flare to burn this quantity of gases. It determined that the new PRDs did not cause a need for an increased flare size: *"None of the new PRDs contribute to the flare load for any of the common release scenarios that impact the flare size."*[98] No mention was made of emissions, for example, during refinery shut down due to the new connections.

PSVs are safety devices, for the *purpose of* venting quickly to avoid overpressure of vessels. They are designed and sized to allow very fast depressurization to avoid over-pressure conditions in refinery vessels. They are not designed to prevent emissions, but instead, to ensure that gases *are* emitted (in these cases to the flare).

[96] https://www3.epa.gov/airquality/sulfurdioxide/health.html

[97] Draft Title V analysis, p. 63, (148th p. of pdf)

[98] Tesoro Application (A/N) 575841 for the Project, provided by the AQMD as part of the LARIC Draft Title V review, at 780th page of the pdf, provided May 12th 2016 to CBE by email from the AQMD (Danny Luong).

G1-81.73 cont'd.

Response G1-81.73

As explained in Response G1-81.72, SCAQMD Rule 1118 requires monitoring of sulfur content of vent gases that are combusted in a flaring event. The monitored sulfur content of the vent gases is used to calculate the SOx emissions from a flaring event. The sulfur content of the vent gas can vary depending on the nature of the process upset. Therefore, predicting the emissions from a flaring event is speculative.

Data regarding PSV relief load presented in Table 7 have been misapplied to emission calculations. The relief load data excerpted from the February 24, 2016 engineering evaluation, not the Title V permit as the comment claims, are to determine if the new PRV/PSV would exceed the capacity of the existing flare. PRVs are safety devices, which are normally closed and do not create an increase in total flow from a unit. Additional PRVs allow the existing unit to depressurize from more locations within the unit, but the volume of material in the unit that would need to be vented would be the same. Therefore, there is no increase in vented gas from

the addition of PRVs to the existing process units proposed to be modified as part of the proposed project. This is analogous to adding a pressure relief device to a home pressure cooker, which normally has one pressure relief device. The amount of steam that is released from two equally sized pressure cookers; one with one pressure relief device and the other with two pressure relief devices, is the same because the amount of steam inside the pressure cookers is the same. If all the pressure relief devices are the same size, the pressure cooker with the two relief devices would de-pressure more quickly.

As explained in G1-78.207, Tesoro strives to operate without flaring. If possible, activities such as equipment or unit shutdowns are planned so that equipment venting is maintained within the flare gas recovery system capacity. In accordance with the Flare Minimization Plan submitted to the SCAQMD, Tesoro evaluates planned shutdown/startup events to minimize the need for flaring and has successfully shutdown and started units without the need to flare. Planned shutdowns do not vent through PRVs, but instead are vented through process valves. Therefore, the addition of PRVs to the unit has no effect on planned unit shutdowns.

Comment G1-81.74

> **The new Project PSVs vent from refinery vessels containing VOCs and sulfur gases, to flare systems.** Inside the refinery, large compressors normally keep refinery gases to a smaller volume and "recycle" or use these gases, for example, as fuels. However, when the refinery has to shut down for planned maintenance, or for emergencies, these flares in turn are designed to burn very large quantities of gases quickly. They are emitted out of the flare stack flame to the air during

G1-81.74

emergency and planned shutdown, and for smaller pressure releases. John Zink Co. LLC, the main refinery flare designer and manufacturer used by oil refineries, describes the process where gases go to the flare and are burned during upset conditions:[99]

> **A flare system** consists of a vapor header that collects the flare gases from various sources, a knockout vessel, a liquid seal vessel, and the flare itself. . . .
>
> When all compressors are operating at full capacity and if the process vent flow rate continues to increase, flare gas will begin to pass through the liquid seal and flow to the flare stack. Therefore, the safety function of the flare system is maintained in the event of process upset conditions.

Consequently, the Tesoro Attachment #6 and the AQMD Title V evaluation evaluates whether the flare systems can handle the large amounts of gases to be added through venting the new PSVs, and whether this could cause an "adverse impact" on the flare, meaning exceeding the flare's capacity to burn the gases, since flares have limits on how much gas they can handle at once time. Overwhelming a flare causes smoking and poor combustion.

The conclusion reached by Tesoro, and the District in the permit, is that the *capacity* of the flare systems would not be exceeded. In other words, the flare is sized large enough to handle burning the gases from all the new PSVs that will be connected due to the new Project. This does not attempt to provide any information or evaluate emissions resulting due venting of PSVs to the flare, especially during a large scale startup or shutdown, which happens periodically. The documents only state:

G1-81.74 cont'd.

> **"The additional load to the No. 5 Flare from the new PSV tie-ins** from the Naphtha Hydrodesulfurization Unit, LPG Railcar Loading/Unloading Rack, and Alkylation unit **will not cause the capacity of the flare to be exceeded**." [emphasis added]

In another case, the Title V permit states:[100]

> **The new PSVs do not contribute to any of the common relief scenarios that impact flare size.** Thus, they do not change the back pressures on existing PSV during any of the common failure scenarios.

Again, the discussion here is regarding whether the flare is sized large enough to handle the relieving PSVs, not whether relief of the new PSVs has the potential to add significant emissions during startup, shutdown, maintenance, malfunction, or other flaring events.

Clearly burning thousands of pounds per hour of refinery gases, as shown above, would result in significant criteria pollutant impacts that were not identified in the DEIR. Avoiding exceeding flare capacity does not equate to avoiding emissions. If it did, then the existing refinery flare emission baseline would show zero emissions, which of course, is not the case.

The Naphtha Hydrodesulfurization unit listed above is a high-sulfur process, so sulfur compounds present in these gases vented to the flare would result in high SOx emissions. As shown in the baseline data reported by Tesoro to the District and charted earlier, in 2014 and 2015 Tesoro emitted over a thousand of pounds of SOx in a day from its flares, even without these new connections of PRDs to the flares. Adding these new connections has the potential to cause significant increased SOx emissions that need to be quantified.

The AQMD baseline flare data for 2014 and 2015 also showed thousands of pounds of CO, NOx, and PM10, and VOCs emitted by Tesoro, so adding twelve new PSV connections has a potential to also cause thousands of new pounds per year, and from hundreds to thousands of pounds per day of these pollutants individually.

Oil refinery flaring with large emissions continues to be common in the South Coast District due to planned and unplanned shutdowns, power outages, fires, and explosions. The DEIR needs to evaluate and include in the Project assessment, emissions from episodic events including malfunctions and startup/ shutdown events, due to the Project. Furthermore, startup/shutdown emissions are required to be analyzed as part of CEQA, and in federal permitting.

A report submitted to the U.S. EPA (Emission Estimation Protocol for Petroleum Refineries) found that flare SSM (Startup, Shutdown, and Maintenance) emissions can be very large and accurate accounting of these is critical:[101]

> When the sulfur recovery plant is in operation, the sulfur plant vent flow rate is fairly small so that the SO2 emissions from the sulfur recovery plant are also relatively small. If the sulfur recovery plant must be taken offline due to an upset or malfunction, the sour gas may be temporarily directed to a backup sulfur recovery unit or directed to a flare or the thermal oxidizer. **If the sour gas in these cases is sent to a flare or thermal oxidizer, the SO2 emissions can be very large. As such, it is critical to include accurate accounting of SO2 emissions during startup, shutdown, or malfunction (SSM) events associated with the sulfur recovery plant.** (at p. 5-17)

This point applies not just to sulfur recovery plants, but to any potential flaring events with a high sulfur percent. However, the Project does have the potential to increase use of the sulfur recovery unit, because of additional desulfurization, which down the line ends up in the sulfur recovery unit (SRU). The SRU must regularly go through startup, shutdown, and maintenance, so these flare emissions must be evaluated too.

G1-81.74 cont'd.

[99] Process Diagram, John Zink Hamworthy Combustion Flare Gas Recovery Unit, http://www.johnzink.com/products/flare-gas-recovery/process-diagram/ Attachment 39

[100] Draft Title V permit analysis, 148th pdf page, also as originally provided by Tesoro's report to the AQMD in its Title V application, the previously cited Attachment 6 (A/N 575841 at 782nd page of pdf)

[101] May 2011, Submitted to: Office of Air Quality Planning and Standards U.S. Environmental Protection Agency Research Triangle Park, by: RTI International, excerpts in Attachment 40, full report available at: https://www3.epa.gov/ttnchie1/efpac/protocol/Emission_Estimation_Protocol_for_Petroleum_Refinerie_052011.pdf

Response G1-81.74

See Master Response 15 and Responses G1-81.69 through G1-81.73 which explain that simply adding PRVs to the flare system does not affect flaring or cause an increase in flare emissions. The SCAQMD Engineering evaluations concluded that flaring emissions are not expected to increase as a result of the proposed project (see SCAQMD Engineering Evaluations AN575839 page 79, AN575840 page 77, and AN575841 page 75). To ensure that accurate accounting of flaring emissions occurs, SCAQMD Rule 1118 requires monitoring of key parameters to accurately determine the emissions resulting from flaring events (see Response G1-81.72). As explained in Master Response 4 and Response G1-81.66, the Refinery operates near capacity in the existing SRPs and the proposed project does not include an increase in the SRP capacity. As described in Response G1-81.69 through G1-81.73 and Master Response 15, the proposed project is not expected to increase flare emissions. The Refinery is subject to SCAQMD Rule

1118 requirements, and will continue to be subject to these requirements following implementation of the proposed project.

Comment G1-81.75

This report also found:

> Emissions from flares consist of a fraction of the hydrocarbons in the flare gas (e.g., CH4, CO, VOC, and specific organic HAP) that are not combusted in the flare; SO2 resulting from the oxidation of sulfur compound impurities, such as H2S, in the gas stream; and CO2 from the combustion process. Flares are also expected to produce NOx emissions and may produce PM (soot) if combustion conditions are not adequate. **A complete emissions inventory will include estimates for all these compounds (the specific organic HAP [Hazardous Air Pollutants] will vary based on the composition of the gas being flared).** (at p. 6-1)

G1-81.75

G1-81.75 cont'd.

Response G1-81.75

The comment makes no reference to the DEIR. The comment quotes the first paragraph of Section 6 for Flares in the U.S. EPA Emission Estimation Protocol for Petroleum Refineries, May 2011.[274] The Protocol explains the difficulty in accurately calculating emissions from flares due to the variability in the conditions associated with flaring. A hierarchy of estimation methodologies is presented. SCAQMD Rule 1118 implements the highest rank estimation technique presented in the Protocol.

Comment G1-81.76

> In conclusion, the DEIR needs to provide specific percentage of VOC (ROG) content, sulfur percent, other gases such as hydrogen, inert gases, etc., present in the vessels that are connected by PSVs to the flares, and publicly provide the emissions assessments and assumptions based on the full potential to emit during planned and unplanned events, startups, and shutdowns for all flares due to the Project. **There is a significant potential for very large flaring events, in the hundreds to thousands of pounds per day of each of SOx, VOCs, CO, NOx, and PM2.5/PM10**. There is also a potential for significant emissions of Toxic Air Contaminants from flares that needs to be assessed, especially when combustion is poor.

G1-81.76

Response G1-81.76

As explained in Responses G1-81.69 through G1-81.75 and Master Response 15, no foreseeable increase in flaring emissions are associated with the proposed project. The SCAQMD Engineering evaluations concluded that flaring emissions are not expected to increase as a result of the proposed project (see SCAQMD Engineering Evaluations AN575839 page 79, AN575840 page 77, and AN575841 page 75). Additional PRVs connected to the flare gas recovery system do not equate to additional flaring. Therefore, the DEIR appropriately included the PRVs as fugitive emission components in the respective unit modifications and no additional flaring emissions were calculated.

[274] https://www3.epa.gov/ttnchie1/efpac/protocol/Emission_Estimation_Protocol_for_PetroleumRefinerie_052011.pdf.

Comment G1-81.77

3. The Project permit conditions do not limit flare emissions to zero, they guarantee burning gases from the new relief valves in the flare, and causing emissions during startup, shutdown, turnaround, and "essential operating needs"

The proposed permit conditions in no way limit flaring emissions to zero, cannot prevent large flaring emissions, and in fact specify activities that will vent gases to be burned in flares. The Draft Title V permit identifies the following conditions for various pieces of equipment connected to the flare (for example, the 44th page), which finds that during Emergencies, Planned Shutdowns, Startups, or Turnarounds, and for "Essential Operating Needs," vent gases may be "directed to a flare" (burned in the flare by the pilot flame which is always on, and which allows ignition of the gases directed to it). This is consistent with the requirements of AQMD Flare Control Regulation 1118, which allows flaring for these activities.[102]

Vent gases from all affected devices of this process/system shall be directed to a gas recovery system, **except for the venting of gases from equipment specifically identified in a permit condition, and for the following events for which vent gases may be directed to a flare:**

1) Vent gases **during an Emergency** as defined in Rule 1118;

2) Vent gases resulting f**rom Planned Shutdowns, Startups and/or Turnarounds** as defined in Rule 1118, provided that the owner/operator follows the applicable options and any associated limitations to reduce flaring that were identified, evaluated and most recently submitted by the owner/operator to the Executive Officer pursuant to Rule 1118, or any other option(s) which reduces flaring for such events; and

3) Vent gases due to and resulting from an **Essential Operating Need,** as defined in Rule 1118.

The evaluation of options to reduce flaring during Planned Shutdowns, Startups and/or Turnarounds shall be updated annually to reflect any revisions, and submitted to the Executive Officer in the first quarter of each year, but no later than March 31st of that year.

G1-81.77

This process/system shall not be operated unless its designated flare(s) are in full use and have valid permits to receive vent gases from this process/system.

Vent gases shall not be released to the atmosphere **except from the existing safety devices or relief valves** on the following equipment: . . .

G1-81.77 cont'd.

These conditions also make it clear that evaluation of options for "reducing" (not eliminating) flaring should be done once a year. These permit conditions in no way eliminate emissions from PRVs and flares. In fact, they guarantee them during flare combustion of vent gases for startup, shutdown, turnaround, and essential operating needs.

[102] AQMD, Regulation 1118, Control of Emissions from Refinery Flares, available at: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1118.pdf?sfvrsn=4

Response G1-81.77

The flare is a safety device for use when unexpected conditions arise and for planned control to maintain a safe startup or shutdown. Because the flare is a safety device, it cannot be permit limited to zero emissions as suggested in the comment. As explained in Responses G1-81.69 through G1-81.76, no foreseeable increase in flaring emissions are associated with the proposed project. The SCAQMD Engineering evaluations concluded that flaring emissions are not expected to increase as a result of the proposed project (see SCAQMD Engineering Evaluations AN575839 page 79, AN575840 page 77, and AN575841 page 75). Additional PRVs connected to the flare gas recovery system do not equate to additional flaring as claimed in the comment.

Comment G1-81.78

The Draft Title V permit also identifies exemptions for flare systems as part of NOx and SOx RECLAIM program emissions reductions:[103]

> Reg. XX - Regional Clean Air Incentives Market (RECLAIM)
>
> This facility is subject to RECLAIM requirements. The No. 51 Vacuum Distillation Unit Heater (D63) is a Major NOx source and is therefore required to be monitored by a Continuous Emissions Monitoring System (CEMS). . . .
>
> **Under §2011(i) and §2012(k), monitoring, reporting and recordkeeping for NOx and SOx is not required for gas flares. Therefore, these rules do not apply to the flare systems. Continued compliance with the requirements of this rule is expected.**

G1-81.78

The Potential to Emit from new PRV connections to flares will increase the Potential to Emit for the Project by at least hundreds to thousands of pounds per day of VOCs, SOx, CO, NOx, and PM2.5/10. Toxic Air Contaminants from flaring also needs to be assessed. The HRA (Health Risk Assessment) should also be re-calculated for impacts of the full Potential to Emit of Flares.

[103] For example, Draft Title V at 188th p. of pdf.

Response G1-81.78

As explained in Responses G1-81.69 through G1-81.77, the new PRVs connections to the flare gas recovery system are not expected to increase flare emissions. PRVs are safety devices, which are normally closed and do not create an increase in total flow from a unit. Additional PRVs allow the existing unit to depressurize from more locations within the unit, but the volume of material in the unit that would need to be vented would be the same. The SCAQMD engineering evaluation concluded that no change in the emissions from the flare would occur. Flare emissions are reported in the Annual Emission Reporting program, which accounts for non-RECLAIM emissions.

The PRV emissions and the associated potential health risk from fugitive emissions from the PRVs were included in the criteria pollutant calculations (VOC emissions) for the respective units (see DEIR Table 4.2-4 and supporting calculations in Appendix B-3 on page B-3-101) and in the HRA, the TAC emissions were included in the TAC emissions modeled for each respective unit. The detailed HRA is contained in Appendix B-4 of the DEIR.

Comment G1-81.79

B. Heater and Boiler use was greatly expanded, but found in some cases to *decrease* in emissions, without a clear basis, sometimes leaving out best technology assessment

Oil refinery heaters and boilers are very large, driving forces in refinery processes, are major users of energy (fossil fuels), and major sources of emissions. These include NOx, SOx, PM10, CO, VOCs, CO2, toxics, etc. It is important that modifications be fully evaluated for potential emissions increases with clear documentation, and strict consideration of requirements for application of BACT or BARCT (Best Available Control or Retrofit Control Technology).

G1-81.79

Response G1-81.79

The proposed project does not greatly expand heater duty as the comment claims. Tables 4.1-1 and 4.2-7 of the DEIR present the change in heater utilization and change to modified heaters, respectively. As shown in Table 81.79-1, the total increased heater duty from heaters listed in Table 4.1-1 is approximately 27.3 mmBtu/hr and the reduction in heater duty from modified heaters listed in Table 4.2-7 is 478.9 mmBtu/hr, which results in an overall reduction of 451.6 mmBtu/hr.

Table 81.79-1

Overall Heater Duty Change from the Proposed Project

Unit	Heater	Duty Increase (mmBtu/hr)
Increased Utilization		
Wilmington DCU	H-101	7.0
Wilmington HTU-3	H-30	4.1
Wilmington HTU-3	H-21/22	4.1
Wilmington CRU-2	H-510	0.4
Wilmington CRU-2	H-501A/501B/502/503/504	1.6
Wilmington Boilers	Boilers 7/8/9/10	10.0
Sulfur Recovery Plant	H-1601/1602	0.125
Subtotal, Increased Utilization		27.3
Combustion Sources Modified by the Proposed Project		
Wilmington FCCU Shutdown	CO Boiler	-300.0
	H-2	-37.4
	H-3	-94.7
	H-4	-127.2
	H-5	-44.0
	B-1 Startup Heater	-84.0
Wilmington HCU	H-300 and H-301	25.0
Wilmington DCU	H-100	50.4
SARP	Process Air Heater, Decomposition Furnace, and Converter Heater	67.0
Carson NHDS[(a)]	NHDS Heater RW 0053	0.0
Carson No. 51 Vacuum Unit	51 Vacuum Unit Heater	60.0
Subtotal, Combustion Sourced Modified		-478.9
Overall Change in Heater Duty at the Refinery		**-451.6**

Note: Negative numbers represent emission reductions.

(a) Modification to install ultra-low NOx burner with no change in firing rate.

The emissions associated with changes in duty of the heaters in the proposed project were fully evaluated in Section 4.2 and Appendices B-3 and B-4 of the FEIR. Heaters requiring permit modifications have undergone or will undergo engineering review by the SCAQMD engineering

staff prior to issuance of permit modifications, which will include a BACT applicability determination and required use of BACT where applicable.

Response G1-78.206 explains how an emission decrease will be achieved while the permit described duty of a heater is increased. Permit conditions limiting daily and hourly average emissions would be imposed to ensure there will be emission decreases associated with the permit revision for the DCU H-100 heater.

Comment G1-81.80

1. The DEIR shows extensive increased use of heaters, boilers, and incinerators

The Project includes extensive modifications on over a dozen existing heaters, boilers and incinerators, including increasing maximum permit limits:[104]

G1-81.80

Table 8: Extensive Project Heater Modifications

Shutdown	Wilmington FCCU: •CO Boiler, •H2 Heater, •H3 Heater, •H4 Heater, •H5 Heater, •Startup Heater
Construction of New Heaters	For new Sulfuric Acid Regeneration Plant
Increased Maximum Permitted Firing Rates	Carson •51 Vacuum Unit Heater, Wilmington Heaters **•H-100,** •H-300, •H-301, **(H-100 used in examples below)**
Increased Utilization	Carson Heaters: •Light Hydrotreating Unit Heater, •FCCU Pre-Heater, Wilmington Heaters: •Delayed Coker Unit H-101, Hydrotreater Unit #3 •H-30, •H-21/22, Catalytic Reforming Unit •H-510, •H-501A, •H-501B, •H-502, •H-503/504 Wilmington Boilers: Steam Generating Boilers •7, •8, •9 and •10, Sulfur Recovery Plant Boilers •H-1601/1602 Incinerators: Sulfur Recovery Plant •F-704 and •F-754.
Modification	Carson •Naphtha Hydrotreater Heater

G1-81.80 cont'd.

The DEIR list above states that there will be new construction, increased firing rates, and increased use of heaters, as well as modifications to one heater and shutdown of the Wilmington FCCU heaters.

[104] DEIR for example, Appendix B-3, Operational Emissions, at pp. B-3-5 to B-3-6

Response G1-81.80

The DEIR fully analyzed proposed project impacts, including increased use of and modifications to numerous process heaters. As indicated in Section 4.1.2 of the DEIR, in addition to direct impacts, the proposed project may have indirect impacts on downstream equipment, including Refinery heaters, by causing increased utilization from operational changes, even though the equipment is not part of the proposed project, that is, it is not modified in any way, it is operating within existing permit limits and no permit modification would be required. The anticipated indirect operational changes are described in Section 4.1.2 and are included as part of the

analysis of operational impacts in Section 4.2.2.2. In spite of the potential for increased operation of the various Refinery heaters, overall the proposed project will produce emission reduction benefits. See Response G1-81.79 for the overall heater duty change from the proposed project.

Comment G1-81.81

2. The DEIR includes contradictions, stating certain heater use will increase, but emissions will not, and therefore Best Available Control Technology is not required

The DEIR finds that some modifications are for the purpose of standardizing the *form* of the permit limits. In the example of the Delayed Coker Unit (DCU) H-100 Heater, the limits would increase from 252 to 302.4 mmBtu/hr of heat input (a measure of the fuel used in the heaters, in million British Thermal Units per hour), and change from a "design heat release" basis, to "maximum heat release" basis, according to the DEIR, which is stated as an industry standard. [105]

G1-81.81

However, the DEIR also states that these new limits will allow for increased *use* of certain heaters, so this is not just a change in format. Since these heaters are undergoing *no physical changes* or improvements to reduce emissions, it is hard to imagine how heater *use* could be increased (which requires burning more fuels), without *increasing emissions,* even with new permit conditions, unless something else is changing. If the permit limits do not preclude increased heater use, then they cannot preclude increased emissions unless the heater is being improved. Emissions increases cannot be defined away by a statement that they will stay the same.

If the purpose is only to convert the measurement units to a different form—an industry-standard description of heat input limits that was otherwise equivalent—then there should be no resultant increase in heater *use* as a result of this change. Conversely, any new permit limits that still allow increased heater use, must mean increased fuel use is allowed, and this inherently means increased emissions.

The DEIR Appendix B-3 Heater calculations also state that emissions of Heater H-100 will not increase despite the District providing increased maximum firing rates. This appendix states that this conclusion is based on Tesoro's belief that emissions can be kept down: *"Although Tesoro has requested an increase in equipment description maximum firing rate for this heater,* ***Tesoro believes that it can maintain post-project heater emissions at or below the current maximum levels."*** [106] It also finds that BACT requirements (Best Available Control Technology for new or modified pollution sources) will not be triggered: ***"As the modification will not result in an emissions increase, BACT is not triggered by this modification."*** [107]

G1-81.81 cont'd.

The DEIR also finds the increased heater heat input, will allow increased crude oil throughput of 6,000 barrels per day at the refinery:

> **This revision to the heater equipment description has the potential to increase the crude oil throughput to the Refinery by up to two percent (or up to 6,000 bbl/day).** The increased heat release from the H-100 heater and/or increased crude oil throughput is anticipated to occur once the modified permit is issued. Therefore, the draft environment impact report (DEIR) evaluated the impacts from the increase in crude throughput of up to 6,000 bbl/day.[108]

It is not possible to increase use of a heater *without* causing more emissions, unless the heater performance is improved in some way. **Since no improvements are identified, and physical changes are ruled out, then the emissions must increase.** The DEIR needs to explain this discrepancy.

[105] DEIR at p. 4-2: *". . . The description will be changed from the **'design heat release'** basis (**252 mmBtu/hr**) to the industry standard **'maximum heat release'** basis (**302.4 mmBtu/hr**). **This revision of the permit description does not involve any physical modifications, but would increase use of the heater** which will enable more efficient production of gas oil and distillates from the feed to the DCU. **Although the described duty of the heater will increase to 302.4***

[106] At p. B-3-9

[107] *Id.*

[108] Draft Title V modification, 274th page of pdf

Response G1-81.81

The issues raised in the comment are addressed in Response G1-78.204. Although the proposed project will allow the DCU H-100 heater to fire closer to its maximum rated capacity, emissions from the heater will nonetheless decrease because new permit conditions will limit emissions from the heater. The new permit conditions ensure a reduction in emissions from baseline. This is because the DCU H-100 heater may have operated at higher emissions in the past (i.e., in the baseline period) than it has operated in the recent past (i.e., the period used for the new source review). It should be noted that even non-compliant activities can constitute "existing conditions".[275] In order to comply with these conditions, Tesoro will have to operate the heater more efficiently and within more restrictive operating specifications) so that emissions limits are not exceeded. Additional control of heater operating conditions, increased routine maintenance, and strict enforcement of permit conditions will ensure that the Refinery operates within these more stringent requirements.

The increased utilization of other heaters (H-101, H-30, H-21/22, H-510, H501A/501B/502/503/504, Boilers 7/8/9/10, and H-1601/1601, see Table 81.79-1) is a result of the potential increase in 6,000 bbl/day of crude oil processing in the DCU. As described in Response G1-81.80, the increased utilization of the unmodified heaters is within the existing permit limits. The increased heater emissions associated with increased heater utilization has been included in the DEIR analysis (see, for example, Table 4.2-4 of the DEIR).

Comment G1-81.82

The AQMD appeared to at least initially agreed to the obvious implication that an increase in maximum heat rating equated to increased emissions. An email from the AQMD included in an application for the Project stated: *"The proposed increases in the heat input ratings will be considered modifications to the heaters which will have potential for emissions increases."*[109]

> Section 2.7.2.1: The EIR states that the "correction of the described duty" for Heater H-100 serving the Delayed Coking Unit at LAR – Wilmington Operations (maximum firing rate increase from 252 MMBtu/hr to 302.4 MMBtu/hr), will result in an increase in crude oil processing capacity of 6,000 bbl/day. However, the proposed increase in permitted heat input rating for the No. 51 Vacuum Distillation Unit feed heater (D63) at LAR – Carson Operations (maximum firing rate increase from 300 MMBtu/hr to 360 MMBtu/hr) does not have potential to increase the crude oil processing capacity. Since the Delayed Coking Unit is a process unit further downstream than the Vacuum Distillation Unit, why will the permit modification for the No. 51 Vacuum Distillation Unit heater (D63) not have an associated increase in crude oil processing capacity?? The proposed increases in the heat input ratings will be considered modifications to the heaters which will have potential for emissions increases.

(It is also interesting to note the District identified a concern that the No. 51 Vacuum Distillation Unit heater would have a similar potential for increased crude oil throughput. The DEIR should answer the question that was put here.)

G1-81.82

[275] Riverwatch v. County of San Diego (1999) 76 Cal. App. 4th 1428.

[109] Email correspondence attached to Application from Tesoro to the AQMD. This application (A/N567645) was part of the set of applications listed as the relevant applications on the first page of the Draft Title V revisions, and was provided to CBE and the public 4/8/16 by Danny Luong, AQMD. See 901st page of pdf for email from Rafik Bashai, (AQMD), June 2015, to Cynthia Carter (Tesoro), Comments Regarding the Draft EIR for the Tesoro Refining Integration and Compliance Project.

Response G1-81.82

The quote in the comment was a misinterpretation of the proposed project, in that the Wilmington Operations DCU is configured differently than the Carson Operations. As shown in Figures 2-8 and 2-10 of the DEIR, the Carson Operations No. 51 Vacuum Unit does not accept crude oil feed, whereas the Wilmington Operations DCU does accept crude oil feed. The email quoted was sent in June 2015, and shows that SCAQMD questioned whether the Carson Operations No. 51 Vacuum Unit accepted crude oil feed, and as explained above, determined that it did not. Therefore, no modification to the DEIR was required. Subsequent discussions and evaluations resulted in proposed permit conditions to limit emissions from both DCU H-100 and No 51 Vacuum Unit Heater.

Response G1-78.206 explains how an emission decrease will be achieved while the permit described duty of a heater is increased. Permit conditions limiting daily and hourly average emissions would be imposed to ensure there will be emission decreases associated with the permit revision for both DCU H-100 and No. 51 Vacuum Unit Heater.

Comment G1-81.83

It is even stranger that the DEIR finds there would be a sizeable *reduction* in NOx with this *increased* heater use, and also reductions of CO, PM10, and VOCs, but an *increase* in CO2E:[110]

Table 9: DEIR daily and annual DCU heater emissions changes

Wilmington DCU H-100 Heater Duty Bump (b)	NOx	SOx	CO	PM10	VOC	CO2E
Lbs/day	-171.03	86.69	-5.14	-0.98	-0.43	201,024.40
Tons/year	-4.38	35.38	3.63	0.75	0.80	36,686.95

An additional note from DEIR Chapter 4 p. 4-17: **(b)** Negative numbers represent emission reductions as a result of permit limits imposed, which will reduce emissions to less than historically achieved.

G1-81.83

[110] From Appendix B-3 Table A-1

Response G1-81.83

Criteria pollutants (i.e., NOx, SOx, CO, PM10, and VOC) have peak daily significance thresholds and are evaluated differently than GHG. Response G1-81.81, Master Response 12 and Response G1-78.204 describe the emission calculations for criteria pollutants.

GHG emissions have an annual significance threshold. Therefore, when annual emissions have a potential to increase, as is the case for the DCU H-100 heater, GHG emissions are expected to increase as presented in the DEIR (See Table 5.2-6 of the DEIR)

Comment G1-81.84

There are additional inconsistencies in the DEIR results:

- **In the table above, some pollutants show reductions, others show increases, even though they are co-pollutants emitted at the same time by combustion from the same heater:** The DEIR should identify why CO2 shows consistently *higher* emissions (positive numbers) at both the daily and annual emissions rate, but the other combustion emissions with the heater's increased use, as described in the DEIR, but the pollutants with lowered emissions are not.

G1-81.84

G1-81.84 cont'd.

Response G1-81.84

See Response G1-81.83.

Comment G1-81.85

- **CO2 is shown with a steady emission rate from day to day over the year, but the other co-pollutants don't show this**: Except in the case of CO2, the tons per year numbers don't add up to the pounds per day multiplied by 365 days per year (and converted to tons). This is an inconsistency, because all these emissions are combustion by-products emitted by the heater at the same time due to burning hydrocarbon fuel, so if CO2E is emitted at the same rate, every day of the year, then the heater must be running at the same rate for the whole year, and the other pollutants should be emitted at the same rate for the entire year. Why then do the other pollutants' daily emission rates not apply to the whole year, as CO2E does?[111] The DEIR needs to explain this, especially the future emissions are based on emissions factor estimates.

Tesoro's application for the change to H-100 states that it normally operates 24/7, all year, indicating that the CO2 emissions assessment (using the same rate of operation every day all year long) is the actual operation of this heater, which indicates that the criteria pollutant increases estimations should also use the daily max every day for the year:[112]

Operating Schedule

See Section 4. During normal conditions, this equipment operates 24 hours per day, 7 days per week and 52 weeks per year.

G1-81.85

[111] After converting to tons by dividing by 2000.
[112] Tesoro Application 567439, 7th page of pdf

Response G1-81.85

As described in G1-81.83, criteria pollutants (i.e., NOx, SOx, CO, PM10, and VOC) have peak daily significance thresholds and are evaluated differently than GHG. Response G1-81.81, Master Response 12 and Response G1-78.204 describe the emission calculations for criteria pollutants.

It should be noted that the CEQA significance thresholds for CO_2e are based on annual emissions, while the CEQA significance thresholds for criteria pollutants are based on a peak day. Therefore, the comparisons that are made in the comment between CO_2e and other pollutant emissions are inappropriate because the calculation methodologies are different for CO_2e (annual emissions) and criteria pollutants (peak daily emissions). As described in Master

Response 12, baseline criteria pollutant emissions for modified heaters were calculated using 98th percentile (near-peak) emissions data. Baseline CO_2e emissions were based on reported annual emissions for the baseline period. In order to ensure that worst-case emissions are projected and analyzed for the proposed project, post-project emissions for all pollutants are calculated based on a peak day, and the CO_2e daily emissions are multiplied by 365 to project maximum annual emissions.

Response G1-78.204 explains in detail that there will be no physical changes to the DCU H-100 heater. Rather, the permit modification is limited to allowing the heater to fire closer to its maximum rated capacity, while at the same time, imposing permit conditions that limit criteria pollutant (NOx, SOx, CO, PM10, and VOC) emissions from the heater. Annual GHG emission calculations are based on maximum operating conditions 365 days per year to ensure that maximum annual emissions are calculated. Therefore, the daily GHG emission calculation will show an increase, while permit conditions are limiting the peak day criteria pollutants. This is because the DCU H-100 heater may have operated at higher emissions in the past (i.e., in the baseline period) than it has operated in the recent past (i.e., the period used for the new source review).

Comment G1-81.86

3. If H-100 will perform much better without physical changes, this indicates it was performing poorly in the past, and credits should not be generated locking in such inflated emissions.

If it is true that this heater will perform better in the future without physical changes, at the same time that it will be used more, this is a strong indication that the heater was operating unnecessarily poorly in the past, and generating excess emissions. The reason for the improved performance of the heater was not identified in the DEIR (nor was the baseline data for the heater's past emissions provided). The reductions should be verified through publicly-available baseline data. If verified, it would still run counter to public health interests to reward poor past performance by allowing the generation of credits for tuning up the heater performance in some way. Generating credits for this will lock in the unnecessarily high past emissions by allowing another source to increase. The DEIR should evaluate these issues.

G1-81.86

Response G1-81.86

The DCU H-100 heater was operating within the permit limits established at the time of permitting. The permit revision allows the SCAQMD to impose more restrictive permit limits than previously imposed, such that emission reductions will occur. This is because the DCU H-100 heater may have operated at higher emissions in the past (i.e., in the baseline period) than it has operated in the recent past (i.e., the period used for the new source review). The CEQA evaluation is based on actual achieved emissions to establish the baseline, and even non-compliant activities can constitute "existing conditions".[276] The SCAQMD has used a "near-peak" daily achieved baseline to evaluate the proposed modifications to the DCU H-100 heater. Therefore, the emission calculations presented in the DEIR accurately reflect the potential impacts from the proposed project in accordance with CEQA requirements.

[276] Riverwatch v. County of San Diego (1999) 76 Cal. App. 4th 1428.

The comment suggests that emission credits should not be generated (allowed) associated with any emission reductions from DCU H-100 heater. The Refinery has not requested any emission reduction credits for accepting the draft Title V permit limits on the DCU H-100 heater. In addition, because Refinery heaters are regulated by RECLAIM, no additional credits are generated when the heaters are operated at lower NOx emission rates.

Comment G1-81.87

4. The numerical basis for H-100 heater NOx emissions appears to have inconsistencies and an error, which would result in NOx emissions for the Project being significant

G1-81.87

The DEIR does briefly provide a basis for the daily and annual emissions, but it does not adequately document the validity of the basis, emissions factors vary for the same pollutant, and it seems to use a different approach for pre-and post-Project NOx calculations that may not fairly compare these two time periods.

For example, the appendix provided a calculated emission factor for NOx of 0.1214 lb/mmBTU.[113] If this same factor was applied to both the current and the proposed heat input limits (changing from 252 to 302.4 = + 50.4 mmBTU/hr), this would result in a NOx increase of 6 lbs/hr[114] or +147 lbs/day. This is a big contrast to the result ultimately used in the DEIR (-171.03 lb/day, or reduced NOx).

Elsewhere, the DEIR (Table A-3) gives the basis for -171.03 lb/day NOx (decrease) ultimately chosen:

352.47 lbs/day (listed as Pre-Project actual emissions)
minus **181.44** lbs/day (Post-Project Routine emissions).
-171.03 lbs/day

The Post-Project emissions of **181.44** lbs/day NOx were in turn based on another Emission Factor or EF (.03 lbs/mmBTU).[115] (This is a different NOx emission factor than elsewhere given in the DEIR of 0.1214 lbs/mmBTU, also from Appendix B-3).

G1-81.87 cont'd.

Even assuming .03 lbs/day is correct for Post-Project emissions, the calculation above appears to include an error, in use of the *Pre-Project* heat input rate of 252 mmBTU/hr in the Post-Project calculations.[116] We can also reproduce this simple calculation:

0.030 lb/mmBTU x 252 mmBTU/hr = 7.56 lbs/hr, x 24 hrs/day = **181.44** lbs/day,

If the calculation instead used the Post-Project heat input limit of 302.4 mmBTU/hr for Post-Project emissions, this is the result:

0.030 lbs/mmBTU x 302.4 mmBTU/hr = 9.07lbs/hr, x 24 hrs/day =217.73 lbs/day,
(36 lbs/day higher than the 181 lb/day Post-Project number used in the DEIR).

The DEIR should explain why it used a Pre-Project heat input for Post-Project emissions. Adding 36 lbs/ day to the total NOx emissions changes listed in DEIR Table 4-2-4 of 38 lbs/day, would result in 74 lbs/day increase in NOx, which is above the 55 lb/day significance threshold.

[113] From Appendix B-3, page B-3-48, for H-100
[114] 0.1214 lbs/mmBTU X 50.4mmBTU/hr = 6.12 lbs/hr, x 24 hrs/day = 146.8lbs/day
[115] Table A-2., Appendix B-3, p. B-3-48
[116] *"NOx (Daily): Emissions based on R1109 EF of 0.03 lb/mmbtu and 252 mmbtu/hr (previous described firing rate)"* (Table A-2., Appendix B-3, p. B-3-48).

Response G1-81.87

The draft Title V permit imposes a potential to emit of 181.44 lb/day of NOx (see Title V Draft Permit Condition A63.YY). The proposed potential to emit is based on the current permit described firing duty of 252 mmbtu/hr and a SCAQMD Rule 1109 NOx emissions factor of 0.03 lb/mmbtu (252 mmbtu/hr x 0.03 lb/mmbtu x 24 hours/day= 181.44 lb/day; see footnote to heater H-100 found in FEIR Appendix B-3, Attachment A, Table A-2). As part of the proposed project, Tesoro proposes to increase the permit described firing duty from 252 mmbtu/hr to 302.4 mmbtu/hr while maintaining NOx emissions at levels calculated using the 252 mmbtu/hr firing duty. This restrictive, enforceable permit limit is intended to reduce emissions. This is because the DCU H-100 heater may have operated at higher emissions in the past (i.e., in the baseline period) than it has operated in the recent past (i.e., the period used for the new source review). Tighter control of heater operating conditions, increased routine maintenance, and strict enforcement of permit conditions will ensure that the Refinery operates within the more stringent emissions limitation. Draft Title V permit condition D29.XX requires demonstration of compliance with this stringent emission limitation by way of CEMS data or annual source testing.

Pre-project NOx emissions are based on actual emissions of this heater during the baseline period and prior to implementation of the proposed limit (as measured by CEMS). Post-project emissions for this heater, as described above, are based on SCAQMD's proposed NOx emissions limit of 252 mmbtu/hr x 0.03 lb/mmbtu x 24 hr/day = 181.44 lb/day of NOx. The FEIR (Appendix B-3, Attachment A, Table A-3) analysis correctly shows a decrease in emissions from the DCU H-100 heater because actual emissions during the baseline period are higher than the emission limits that are included in the draft Title V permit.

The comment identifies two different NOx emissions factors of 0.1214 lb/mmbtu and 0.03 lb/mmbtu used to calculate emissions from this heater. These emission factors, and their basis, are identified in Appendix B-3, Attachment A, Table A-2 to the FEIR. The 0.1214 lb/mmbtu emission factor conservatively estimates emissions from this heater during periods of startup, shutdown and commissioning (SSC) of the heater; periods when the heater is not operating at sufficient operating temperature to employ SCR NOx reduction control technology. As described above, the 0.03 lb/mmbtu emission factor is used to calculate the proposed potential to emit emissions during peak normal operating day conditions (equivalent to 181.44 lb/day at heater maximum firing rate).

Comment G1-81.88

5. The DEIR also uses routine emissions, not including startup / shutdown emissions

Startup / shutdown emissions seem to have been left out of the emissions for heaters. These emissions are significant, occur regularly, are part of refinery operation, and should be included in emissions estimates. If the total emissions including SSC NOx emissions will *increase* due to the Project (as the DEIR table below indicates), then the DEIR should be corrected to include startup / shutdown emissions for this, and all sources. *[Note to attorneys –including startup/shutdown emissions is I believe a legal requirement]*

As below, the DEIR[117] showed *increased* NOx emissions of 6.12 tons per year (tpy) for DCU Heater H-100, in the case where Startup, Shutdown, and Commissioning emissions were included with routine emissions (labeled "NOx (SSC)"), instead of the decrease of 4.38 tpy when SSC was not included:

G1-81.88

Table 10: DCU Heater H-100 Pre- and post-Project emissions

	Pre Mod Actual Emissions (Lbs/Year)	Post Mod Emissions (Lbs/Year)	Increase (Tons/yr)	Pre-Mod Basis	Post-Mod Basis
NOx (SSC)	74,980.50	87,220.49	6.12	--	--
NOx (Routine)	74,980.50	66,225.60	(4.38)	RECLAIM Data	2014 Permit Application

The DEIR also did not provide the RECLAIM data, or the 2014 Permit Application that were the basis of the pre- and post-Project emissions, which should be added.

[117] Appendix B-3, at p. B-3-50, Table A-4

Response G1-81.88

See Responses G1-78.201 and G1-78.202 that explain the startup and shutdown emissions associated with the DCU H-100 heater. SCAQMD's CEQA significance thresholds are based on a peak day for NOx emissions. Because the DCU H-100 is an existing heater, startup and shutdown emissions already occurred in the baseline and are not expected to change as a result of implementing the proposed project. Additionally, as further explained in Response G1-78.201, total mass emissions during startup and shutdown are typically less than the peak normal operating day. Therefore, peak daily post project emissions compared to near-peak (98^{th} percentile) baseline normal operation emissions is the appropriate scenario used to determine potential impacts. The NOx SSC emissions were not used in the SCAQMD NOx Mass Daily Threshold CEQA significance determination.

In order to ensure that the ambient air quality analysis is based on conservative theoretical, worst-case emissions, the DCU H-100 NOx SSC emissions are used to assess compliance with annual and 1-hour NO_2 Ambient Air Quality standards. The annual NO_2 ambient air quality modeling was conservatively based on using the theoretical maximum emissions during SSC for the allowable startup and shut down days and using the Draft Title V permit NOx emissions limit during normal operations for the rest of the year, less the emissions during the baseline period. The theoretical maximum emissions were calculated based on the physical limitations of the heater, including, the maximum physical firing rate of the heater (302.4 mmBtu/hr) and an

uncontrolled NOx concentration of 100 ppmv[277]. The 1-hour NO_2 modeling was also performed based on the theoretical maximum emissions value for this heater less the emissions during the baseline period. As shown Table 4.2-12 in the FEIR, ambient air quality standards for annual and 1-hour NO_2 are not exceeded as a result of this conservative analysis of the proposed project.

Therefore, Table A-4 in Appendix B-3 has been revised in the FEIR to remove the NOx (SSC) and NOx (routine) rows showing lb/year and tons/year data for the DCU H-100 heater and other sources in the proposed project because they were not used to calculate NO_2 ambient air quality impacts and were not used to determine significance.

Comment G1-81.89

C. There is a greater potential for pipeline spills and the DEIR should add evaluation

The pipelines associated with this Project, and with related Tesoro Logistics projects are extensive and should receive special attention, especially given that this is a a region where a major earthquake is overdue. (See the later section – "*Special attention is needed for earthquake and related fire risks . . .*") Furthermore, this report discussed cleaning and degassing emissions in the above section on tanks, which were also identified as a significant source of emissions in pipelines, and needed assessment in the DEIR. In addition, oil refinery pipeline spills have already occurred in the local area, and Tesoro has had its own major pipeline spills in other locations.
In addition to identified pipelines, one pipeline previously identified in the 2014 Negative Declaration was no longer identified in the DEIR. The 2014 Negative Declaration included a large expansion of a pipeline from the Marine Terminal to the new Storage Tanks, as a change from 12 to 42 inches (over a 12-fold increase in volume – see Neg Dec comments, attached). Since the new storage tanks are still part of the 2016 proposal, and these tanks would still receive crude oil from marine vessels by pipeline, the potential expansion and status of this or other pipelines from the marine terminal should have been identified in the 2016 DEIR. Such a large pipeline expansion, especially in an earthquake zone, has a strong potential to significantly increase impacts, including spills or leaks. Tesoro has already had a history of pipeline spills and violations.

G1-81.89

The status of this pipeline as part of the Project was not readily identifiable in the DEIR, and may have already been carried out, despite the environmental review (the 2014 Negative Declaration) being retracted. The DEIR needs to clarify the status of the pipeline as either no longer planned, already constructed, or sized differently, and how it relates to the Project, including whether it has come under different ownership (such as Tesoro Logistics, which was spun-off from Tesoro). Regardless of ownership, any pipelines from marine terminals to the refinery and especially the new storage tanks or expanded storage tanks are part of the Project, but the DEIR did not explain what happened to the 42-inch pipeline plan, either in the Project or in cumulative impacts. Even if the pipeline would go to existing storage tanks, the DEIR still needs to provide the status of the potential expansion, since the new storage tanks free up capacity in existing storage tanks, so effectively all the refinery storage tanks are impacted by the Project.

G1-81.89 cont'd.

[277] Emissions = (302.4 mmBtu/hr)(100 ppmv NOx)(1.194e-7 lb NOx/scf/ppmv NOx)(8710 dscf/ mmBtu)(20.9%/(20.9%-3% O2)) – reference EPA 40 CFR Part 60, Appendix A, Method 19. See DEIR Appendix B-3, Attachment A, Tables A-2 and A-3.

Response G1-81.89

Hazards associated with pipelines were described in Section 3.3.4 of the DEIR and hazards associated with proposed pipelines were analyzed in the Section 4.3.2.3 of the DEIR. See Master Response 9 for a description of the DEIR's analysis of hazard impacts, including those resulting from earthquakes. De-gassing of pipelines is addressed in Response G1-81.43.

The 42-inch pipeline that was part of the previous Draft Negative Declaration was not a marine terminal pipeline replacement as claimed in the comment, but was a proposed pipeline replacement within the Wilmington Operations to replace the existing 12-inch pipeline that connects to the 24-inch marine terminal pipeline. The pipeline replacement was described in the withdrawn Negative Declaration as sized up to 42-inch and was not included in the DEIR as a 42-inch pipeline because further engineering determined that only a 24-inch pipeline was needed. The 24-inch pipeline is described as replacing the 5,000 feet of 12-inch pipeline on pages 2-39 and 2-40 of the DEIR. The proposed pipeline replacement is identified on Figure 2-14 of the DEIR, which is the same pipeline replacement identified on Figure 1-3 of the withdrawn Draft Negative Declaration. The pipeline proposed in the withdrawn Negative Declaration was included in the DEIR with a more definitive size. Therefore, until completion of the CEQA process, no approval for construction has been granted and no pipeline replacement has gone forth.

Comment G1-81.90

The DEIR does identify an expansion from 12 to 24 inches (making volume four times larger) within the Wilmington operations, and states that there would be no changes at the marine terminal, but this is inconsistent with a down-stream pipeline expansion, but no up-stream expansion: [118]

> Piping within the Carson Crude Terminal will be installed to connect the six new 500,000 barrel tanks to existing pipelines to the Carson Operations and Marine Terminal 1. The two new 300,000 barrel tanks will be connected to existing pipelines from the Wilmington Long Beach Terminal. Within the confines of the Wilmington Operations, the existing 12-inch diameter piping will be replaced with 24-inch diameter piping to connect the replacement tanks to the Wilmington Operations. . . .
>
> Crude oil for the Wilmington Operations is delivered via ship using the pipeline from the Tesoro Marine Terminal at the Port of Long Beach. . . .
>
> Currently Carson and Wilmington Operations are connected via Tesoro and third party pipelines that enable the transfer of intermediate and finished products between the two facilities. The proposed project is not expected to result in any physical changes to the existing marine terminals. Additionally, no changes to the pipelines connecting the marine terminal to the Refinery are planned as a result of the proposed project.

G1-81.90

This seems incongruous. The original project determined that it needed a 42-inch pipeline to offload to the new and expanded storage tanks, but the DEIR only identifies a portion of the pipeline within the refinery that will be expanded to 24, instead of 42 inches, then the rest of the pipeline volume upstream needs to be identified. It would be nonsensical to expand a down-line pipeline to 24 inches, while the up-line portion remains at 12 inches, so it is clear that the up-line pipeline either will be, or has been expanded to a larger pipeline, or that the down-line pipelines at the refinery would be connected to a larger number of up-stream pipes, or some such variation.

Either way, upstream pipelines are part of the Project or at least need cumulative impacts explored.

G1-81.90 cont'd.

[118] DEIR at p. 1-8 to 1-9

Response G1-81.90

As explained in G1-81.89, the proposed 24-inch pipeline is within the confines of the Wilmington Operations. No changes are proposed to the existing Marine Terminals, specifically the Long Beach Marine Terminal and its existing 24-inch pipeline are described on page 2-27 of the DEIR. Page 2-39 of the DEIR discloses that "the proposed project does not require any modifications to the Wilmington Operations Marine Terminal in the Port of Long Beach." The installation of the 24-inch pipeline within the Wilmington Operations will make the Refinery pipeline the same size as the Marine Terminal pipeline. This will reduce the piping hydraulic restrictions in the Refinery and ensure that the proposed increase in the crude oil transfer rate, from 5,000 bbl/hr to 15,000 bbl/hr, can be met. No changes to the Long Beach Marine Terminal, Marine Terminal T-1, or Marine Terminal T-2 are proposed.

The piping within the Carson Crude Terminal is to connect the six new, 500,000 bbl crude oil storage tanks to the existing manifold connected to the existing pipeline from Marine Terminal 1. As disclosed on page 2-27 of the DEIR, no physical or operational change to the existing marine terminals are proposed and no changes to the pipelines connecting the marine terminals to the Refinery are planned as a result of the proposed project. Therefore, there are no upstream pipeline modifications as the comment claims.

Comment G1-81.91

Pipeline impacts are not theoretical – Tesoro already had major spills and was identified for pipeline safety violations; other industry pipelines have ruptured in the Los Angeles region:

- In N. Dakota, Tesoro was responsible for a major oil spill still being cleaned up.[119]
- Tesoro received a notice letter for potential pipeline safety violations in 2009, from the Pipeline and Hazardous Materials Safety Administration (PHMSA), attached.[120]

Tesoro N. Dakota pipeline oil spill site in wheat field

- Phillips 66 also had an oil pipeline rupture in a Wilmington California residential neighborhood (pictured below), causing severe odors, and prompting a visit and comments by Rep. Janice Hahn, D-San Pedro, who visited the site out of "concern for the safety and well-being of the residents of Wilmington," . . . "The harsh, crude oil smell is not only horrible, but can also be potentially harmful to the neighborhood residents and environment."

"As a member of the House Transportation and Infrastructure Subcommittee on Railroads, Pipelines and Hazardous Materials, I plan to make this oil spill incident a priority," . . . "I have already reached out to the subcommittee to find out what federal actions we can take to ensure that an incident like this will not happen again, and that there is proper oversight with our nation's pipelines." . . . "We have to protect the residents of Wilmington and the environment from the risks of hazardous materials transportation."[121]

Phillips 66 2014 Wilmington neighborhood oil spill from Press-Telegram

G1-81.91

The DEIR needs to more fully examine existing underground pipeline threats in the area, increased threats from the Project, and cumulative impacts from Projects in the region. G1-81.91 cont'd.

[119] *'It Will Never Be The Same': North Dakota's 840,000-Gallon Oil Spill, One Year Later,* Emily Atkin, Climate Progress, Oct 21, 2014, http://thinkprogress.org/climate/2014/10/21/3582480/north-dakota-spill-one-year-later/ and *Two years after North Dakota oil spill, dirty pile still dwarfs clean pile,* Amy Dalrymple / Forum News Service, Sep 26, 2015, http://www.inforum.com/news/3848193-two-years-after-north-dakota-oil-spill-dirty-pile-still-dwarfs-clean-pile Attachment 41 and 42

[120] *Notice of Probably Violation and Proposed Compliance Order,* CPF 5-2009-0002, January 6, 2009, U.S. Department of Transportation letter to Tesoro, Michael McCann, Vice President of Pipeline and Terminals, Tesoro Refining and Marketing Company, Attachment 43 https://primis.phmsa.dot.gov/comm/reports/enforce/documents/520090002/520090002_NOPV%20PCO_01062009_text.pdf

[121] Crack in idle Phillips 66 pipeline spews crude oil onto Wilmington streets, Press-Telegram from Sandy Mazza, Daily Breeze, 03/18/14, http://www.presstelegram.com/general-news/20140318/crack-in-idle-phillips-66-pipeline-spews-crude-oil-onto-wilmington-streets Attachment 44

Response G1-81.91

The comment raises issues with pipeline releases and potential violations of pipeline safety requirements.

Tesoro reported that it initiated a quick and thorough response once the pipeline leak in Tioga, North Dakota was discovered. No injuries or impacts to wildlife resulted from the incident. Tesoro is working with the landowner and the North Dakota Department of Health to complete the remediation. An independent, third-party report concluded that the likely cause of the small diameter hole in the pipeline was from electrical discharge, consistent with a lightning strike. Tesoro continues to work with PHMSA to enhance pipeline system integrity and continues to strengthen its systems and controls to prevent pipeline releases.

The Interconnecting Piping associated with the proposed project includes more sophisticated leak prevention, leak monitoring and detection and automatic shut-off equipment than was deployed on the Tioga pipeline at the time of the incident. In addition, the proposed project Interconnecting Piping will be monitored by Tesoro's internal pipeline control center; the Tioga line was monitored by a third-party at the time of the incident.

On January 6, 2009, the PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (NOPV/PCO) to Tesoro Refining & Marketing Company resulting from the inspection of a 0.5 mile fuel gas pipeline at Tesoro's Wilmington Refinery. The inspection occurred in September 2008; 16 months after Tesoro acquired the Wilmington Refinery from another operator.

The NOPV/PCO did not allege any conditions of unsafe pipeline operations, rather all allegations were related to the detail in written procedures. In response to this NOPV/PCO, Tesoro identified that 8 of 17 alleged deficiencies were available in other documents, but were not referenced in the manual that PHMSA inspected. The remaining procedure deficiencies were immediately addressed by revising procedures to include the missing details. PHMSA accepted the revised procedures and closed out the NOPV/PCO on November 2, 2010.

PHMSA recently inspected this same pipeline in September 2016. The PHMSA inspector provided no indications of suspected violations or items of concern during the inspection closeout meeting.

The comment also references a pipeline release and resulting impacts associated with Phillips 66 operations in Wilmington, California. A pipeline release associated with a different operator (Phillips 66) is not related to Tesoro's operations or the proposed project.

Hazards associated with pipelines were explained in the DEIR in the Existing Setting in Section 3.3.4 and hazards associated with proposed project pipelines were analyzed in the Section 4.3.2.3 of the DEIR. Section 5.1.2 of the FEIR presents the projects considered in the cumulative impacts analysis.

Comment G1-81.92

D. California approved the Tesoro purchase of BP Carson despite anti-competitive concerns based on environmental improvements, so the Project should not take credit for the FCCU shutdown

Tesoro was allowed by the Federal Trade Commission and State of California to buy the BP[122] Carson refinery next door to the Tesoro Wilmington refinery in 2013, despite outcries this would be ant-competitive and could increase gasoline prices. Consumer Watchdog found previous to the purchase, that there was already too much concentration of the gasoline market with too few oil companies in California, already causing high gas prices, so the organization opposed the sale as further exacerbating the problem.

Consumer Watchdog found the Tesoro purchase of the BP refinery was a bad deal for consumers, and could increase gas prices![123]

> **As Gas Prices Spike to Record High, Consumer Watchdog Urges California Attorney General to Block Tesoro Purchase of BP Refinery and Arco Gas Stations**
>
> *Otherwise consumers will face even higher prices when Tesoro and Chevron control nearly half of California's fuel refining capacity*
>
> "If the purchase goes through, Tesoro and Chevron will between them own more than half of California's fuel refining capacity, including the three largest refineries in the state," the letter said. "California's drivers and the state economy will pay the price for this merger at the pump. We ask you to halt it on antitrust grounds."

G1-81.92

The purchase means Tesoro and Chevron own half the refining capacity in the state, which is monopolistic. Usually when an oil company buys a refinery in the state they are required to sell another one, to avoid having a small number of companies monopolize the gas market, but Tesoro got away with the purchase without having to sell another refinery. Now Tesoro owns three refineries in the state, and four on the West Coast.

As a contrasting example, in 2001 the Federal Trade Commission investigated the merger of Valero and Ultramar, filed a complaint against them, and required that the merged companies sell one of the California refineries, in order to increase competition, since both already competed in the Northern California market:[124]

> Resolving Anticompetitive Concerns,
> FTC Consent Order Would Allow Merger of Valero Energy and Ultramar,

Valero Required to Divest Golden Eagle Refinery and 70 Ultramar-owned Gasoline Stations

Apparently the atmosphere had become more lax in 2013, because unlike Valero, Tesoro was allowed to proceed without selling a refinery. **The State of California did however identify environmental upgrades as conditions in its approval letter (below).**
Tesoro should not be eligible to generate air pollution credits to offset other air pollution expansions for these environmental improvements that were required for the merger, because they had to do that to get the state approval.

Tesoro is specifically taking credit for pollution cuts from the planned shutdown of the Wilmington Fluid Catalytic Cracking Unit (FCCU) and associated equipment, but the FCCU shutdown is referenced in the letter from the California's Attorney General, as part of the decision to approve the BP refinery purchase. [125]

G1-81.92 cont'd.

Tesoro should not be allowed to take credit for the cuts that were discussed in the Kamala Harris letter, since they were part of the deal that allowed Tesoro to the buy into a much larger part of California's fuels market. The following table shows that Project emissions without allowing credit for the FCCU shutdown are high:

Table 11: Project emissions without credit for the Wilmington FCCU shutdown

NEW AND MODIFIED SOURCES	NOx	SOx	CO	PM10*	VOC	Notes
Total Combined Project Emissions as described in the DEIR (Negatives numbers mean reductions)	-567.98	-248.15	-599.06	-66.43	399.26	From App B-3 p.B-3-14
The above includes the following Total FCCU shutdown w Heaters & Fugitives Emissions	-572.59	-416.38	-959.79	-171.35	-318.96	App B-3, p B-3-14
Total Project emissions without allowing credit for the FCCU Shutdown.	**4.61**	**168.23**	**360.73**	**104.92**	**718.22**	

G1-81.92 cont'd.

Furthermore, the Draft Title evaluation found that the heaters associated with the Wilmington FCCU were never permitted under the District New Source Review (NSR) program. For this reason, the facility operated for decades without such NSR, Best Available Control Technology in place.[127] Tesoro should not receive emissions credits for shutting down the FCCU and associated heaters and other equipment, given the long term, higher-than-necessary emissions. The shutdown should be considered a result of the agreement with the state and Tesoro's modernization.

G1-81.92 cont'd.

[122] British Petroleum
[123] http://www.consumerwatchdog.org/newsrelease/gas-prices-spike-record-high-consumer-watchdog-urges-california-attorney-general-block-t
[124] Federal Trade Commission, December 18, 2001, https://www.ftc.gov/news-events/press-releases/2001/12/resolving-anticompetitive-concerns-ftc-consent-order-would-allow
[125] May 17, 2013, Attachment 45
https://oag.ca.gov/system/files/attachments/press_releases/AG%20Letter%20to%20CEC%20(Tesoro).pdf
[126] *Consumer Watchdog Calls For Sunlight On Big Oil Refiners To Avert CA Gasoline Price Spikes; State Energy Commission Panel To Make Recommendations On Transparency For Refiners,* 4/22/2016, http://www.consumerwatchdog.org/newsrelease/consumer-watchdog-calls-sunlight-big-oil-refiners-avert-ca-gasoline-price-spikes-state-e Attachment 46
[127] Draft Title V calculations, 169th p. of pdf, *["However, the heaters associated with the FCCU (H-2 Heater (D92), H-3 Heater (D89), H-4 Heater (D90), H-5 Heater (D91), FCCU Startup Heater (D1664), and CO Boiler (D112)), **were never permitted under the District NSR program.** For this equipment emissions reductions are calculated as actual emissions over the past two years, reduced to the amount which would be actual if current Best Available Control Technology (BACT) were applied. Attachment #1 contains the calculations for emissions reductions from the heaters, based on current BACT emissions factors."]*

Response G1-81.92

As described in Master Response 13, the comment incorrectly claims that the shutdown of the Wilmington Operations FCCU was a condition of approval for Tesoro's acquisition of the BP Carson Refinery and ARCO branded service stations, and therefore, the baseline for air quality

impacts should not include emissions from the Wilmington Operations FCCU. Consistent with applicable law, the District properly concluded that the baseline includes the existing operation of the Wilmington Operations FCCU. The Federal Trade Commission and the California Attorney General both reviewed Tesoro's proposed acquisition to ensure that the acquisition would not violate federal and state antitrust laws. After a nine-month review, on May 17, 2013, the agencies announced that they had resolved any potential antitrust concerns with the proposed acquisition.

During the antitrust review process, Tesoro submitted documents to the FTC and the California Attorney General stating that Tesoro intended to make certain modifications at the combined Refinery that would allow Tesoro to achieve specified "synergies" between the Wilmington and Carson Operations. Among other changes, Tesoro explained, Tesoro planned to replace some of the combined Refinery's fluid catalytic cracking unit ("FCCU") capacity with additional hydrotreater capacity.

In connection with her approval of the acquisition, the Attorney General entered into an agreement with Tesoro. In this agreement Tesoro agreed to maintain CARBOB capacity for three years, maintain the ARCO brand, and not eliminate jobs for a period of two years. Tesoro also agreed to provide an annual report on the actions taken to achieve the specified synergies, including actions designed to replace FCCU capacity with hydrotreater capacity.[278]

Thus, it is not accurate to say that the Attorney General required Tesoro to shut down the Wilmington Operations FCCU as a condition of approval. Rather, the Attorney General required Tesoro to provide an annual report on the implementation of Tesoro's existing plans to modify the combined Refinery by, among other things, replacing FCCU capacity with hydrotreater capacity. Moreover, operation of the Wilmington Operations FCCU is part of the baseline environmental conditions and the proposed project enables the Wilmington Operations FCCU to be shutdown.

As explained in Section 4.2.2.2 and Table 4.2-4 of the DEIR and Master Response 13, emission reductions are appropriately credited to the proposed project. Further information about the purchase of the BP Carson Refinery by Tesoro can be found on Page 2-1 of the DEIR. Section 4.2.2.2 of the DEIR explains that the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. The proposed project will result in local reductions in GHG emissions as discussed in Section 5.2 of the DEIR and as summarized in Table 5.2-8 (see page 5-26 of the DEIR).

The statement in the permit evaluation cited by the comment summarizes the permitting history of the Wilmington Operations FCCU heaters. SCAQMD's NSR program and the requirement

[278] See Attachment E, Kathleen Foote for Kamala Harris, letter to Robert Weisenmiller, May 17, 2013. In the letter, the Attorney General uses the term "distillate desulfurization unit" to refer to additional hydrotreating capacity. The letter notes that replacing FCCU capacity with "desulfurization" capacity will benefit the environment by reducing emissions and greenhouse gases.

for BACT are applicable when a new emissions source is constructed or when an existing emission source is modified resulting in an emissions increase. The FCCU heaters were constructed prior to the adoption of the NSR program and had not been modified in a way that triggered these requirements since their original construction. As such, there were no permit restrictions placed on the heaters that would limit emissions based on NSR. However, the permit evaluation quoted in footnote 127 above correctly notes that the emissions reductions from shutdown of these units would be reduced to the amount of emissions that would occur if current BACT were applied. The DEIR properly evaluated the impacts of shutting down the Wilmington Operations FCCU. See Response G1-78.211 for further description of this issue. Even if shutdown of the Wilmington FCCU had been required by the Attorney General, the CEQA baseline would still be actual emissions in the baseline period.

Comment G1-81.93

Consumer Watchdog also found in 2016 that:[126]

> In addition, Court pointed out that [the] Exxon increased its gasoline sales by 4% in 2015 despite the fact that its only refinery in Torrance was out for 11 months of the year. Exxon did this through production agreements with its competitors to use their refineries, including Tesoro, that signaled to the other refiners that Torrance would not be online for a long period of time. Meanwhile misinformation about Torrance led the market to believe that the refinery would be back online throughout the year, because Exxon had no duty to report its actual condition or true estimated uptime, sparking shortages and price spikes. [sic]

G1-81.93

[126] *Consumer Watchdog Calls For Sunlight On Big Oil Refiners To Avert CA Gasoline Price Spikes; State Energy Commission Panel To Make Recommendations On Transparency For Refiners*, 4/22/2016, http://www.consumerwatchdog.org/newsrelease/consumer-watchdog-calls-sunlight-big-oil-refiners-avert-ca-gasoline-price-spikes-state-e Attachment 46

Response G1-81.93

The comment refers to the ExxonMobil Refinery in Torrance. It does not raise an issue regarding the proposed project and therefore, does not require a response.

Comment G1-81.94

E. **Special attention is needed for earthquake and related fire risks from the Project because of the large new storage tanks, pipeline expansions, LPG by rail, and increased risk of hazardous chemical release**

It is well established that Southern California is due for a major earthquake. A news report quoting USGS and emergency services experts summarized the risks well, finding an almost 100% chance of a big earthquake within 30 years, and that Southern California had a higher risk within the state. The damage would be severe with a higher magnitude quake, including collapses and fires:

> **How bad would it be?**[128]
>
> "You would see buildings collapse, you'd see people trapped, you'd see roadways collapse," said Kelly Huston of California's Office of Emergency Services. "You'd see widespread destruction." Under the USGS's crisis scenario for a magnitude-7.8 temblor in Southern California, the soil-filled Los Angeles Basin would turn into a violently trembling Jell-O, causing major highways and airport runways to buckle, water and sewer pipes to crack, electrical and gas lines to sever, and thousands of fires to break out across the region. Those blazes could then be whipped into a frenzy by the Santa Ana winds. Fiber-optic cables running across the San Andreas would be torn apart, and infrastructure would take months, if not years, to repair. The hospitals would be swamped by 50,000 injured people, and at least 1,800 would die.

A research geologist stated the southern San Andreas has not had a large quake for more than a century. "That means stress is building, building, building," said Rufus Catchings, a research geophysicist. "It's overdue for a really big one."

This is well known, but unfortunately preparation does not always take a front seat. In the case of the DEIR, when a whole tank farm is being constructed with long pipelines, earthquake and fire risk should receive special attention – it merits a particular analysis. Building codes are designed to reduce seismic risks, not to eliminate them.

G1-81.94

My previously cited 2014 comments on the ND included a discussion of the probability of an earthquake in the region, and potential impacts, such as fire damage to storage tanks (like the storage tank damage due to the Turkish earthquake shown below).

Fire damage to naphtha tanks at Tüpras refinery.

Earthquake risk and prevention measures, including analysis regarding fires, toxic releases, and evacuation planning is essential when further increasing the concentration of flammable and explosive petroleum products, and additional hazardous materials, in an already-heavy industrial zone. Now is the time to do the planning, before a disaster occurs. I am unable to complete further comments on this extensive but key subject, but additional comments on fires and other hazards were identified in previously cited 2014 Fox report on the 2014 Negative Declaration. The broad and severe implications of earthquake and fire hazard should have its own separate analysis.
[128] *When will the Big One strike California?* The Week, April 19, 2014, http://theweek.com/articles/447730/when-big-strike-california

G1-81.94 cont'd.

Response G1-81.94

As explained in Section 4.3 of the DEIR on page 4-52, "the consequence of a hazardous materials release would be the same irrespective of the cause of the release (e.g., human error, equipment failure, sabotage, terrorism, natural disaster, or civil uprising)." It should be noted that the DEIR conservatively assumed that releases of flammable materials would be ignited. As with any incident, the cause(s) of the incident are investigated and industry organizations (such as API) improve design standards (e.g., API has improved tank design standards with API 650 12th edition 2nd Addendum being issued in January 2016) and agencies modify regulations (e.g., CalEPA and CalOSHA has proposed changes to CalARP and CalOSHA regulations). Therefore, the findings/lessons learned from past incidents are been incorporated into design standards. See Master Response 9 and Response G1-78.237 for additional discussion on effects of earthquakes.

Comment G1-81.95

VI. Cumulative Impacts should not have included the SCIG, are Significant, and many Interrelated Projects should be identified and evaluated

A. The Cumulative Impacts are significant and need to be corrected; an incorrect assumption claims reductions for the SCIG project, but its EIR has been invalidated in court

G1-81.95

The Cumulative Impacts section finds no cumulative operational impacts. Unfortunately, this conclusion is based mainly on the false assumption that one project will result in a large reduction in emissions. It showed the Southern California International Gateway project (SCIG) reduced emissions of 5,619 lbs/day NOx (or 2.8 tons per day or tpd), 2,905 lbs/day CO (about 1.5 tpd), 316 lbs/day VOCs, 139 lbs/day SOx, 313 lbs/day PM10, and 228 lbs/day PM2.5:

TABLE 5.2-2

Cumulative Operational Emissions (lbs/day)

No.	Project	VOC	CO	NOx	SOx	PM10	PM2.5
4	Southern California International Gateway Project[a]	-316	-2,905	-5,619	-139	-313	-228
6	ILWU Local 13 Dispatch Hall[b]	19.9	--	26.9	--	16.9	1.5
8	Valero Cogen[c]	33.4	201.8	0	0	95.8	20.6
9	WesPac[d]	-27	-266	-40	<1	-33	-30
10	LAUSD Span K-8 School[e]	8.76	--	--	--	--	--
12	Warren E&P[f]	19.0	14.4	20.5	--	3.7	4.3
15	Sepulveda/Panama Project[g]	339.1	546.9	521.6	2.82	203.9	32.4
16	Shell Revitalization Project[h]	50.83	0	0	0	0	0
21	Phillips 66 Crude Oil Storage[i]	166.8	109.1	249.4	0.3	18.9	12.8
22	Shell Carson Facility E10 Project[j]	0	0	0	0	0	0
23	Carousel Tract[k]	30	200	50	0.48	32	9.1
32	CSULB Foundation Retail Project[l]	4.89	18.95	3.61	0.03	2.26	0.67
34	Tesoro LPG Recovery Unit	0.46	0	0	0	0	0
35	Tesoro Dehexanizer Unit	0.68	0	0	0	0	0
40	Tesoro Storage Tank 956	0.15	0	0	0	0	0

(a) POLA, 2013 (As reported in FEIR, but subject to revision pending outcome of ongoing litigation.) (P. 5-18)

G1-81.95 cont'd.

This is a surprising inclusion in the DEIR, because the AQMD challenged the validity of the SCIG EIR in court and won, and the court put the SCIG EIR aside. Regarding the SCIG and this victory, the AQMD website quoted William A. Burke, Chair of the AQMD Board:[129] *"Communities in the surrounding areas are already highly impacted by air pollution from the ports and other activities,"* and *"The impact this project would have on the residents, school children and others in the area is just unacceptable,"* The AQMD found that the SCIG would actually cause significant negative impacts on air quality:

> **The Port's EIR acknowledged SCIG would have significant air quality impacts on nearby environmental justice communities, including the residences, parks, schools, and a homeless veteran's shelter located in nearby West Long Beach.** The SCAQMD argued that the air quality impacts would be worse than what was disclosed in the EIR and sought inclusion of enforceable mitigation measures to require cleaner trucks and trains as they become available.
>
> **In the court's detailed 200-page opinion, Judge Goode ruled that portions of the EIR's air quality analysis did not disclose the true extent of the project's harm to air quality, and that important air quality mitigations were not enforceable and "could leave outdated technology locked into a major project for half a century."** The court further ruled that the EIR mischaracterized the project as providing an air quality benefit because it ignored the combined impacts of SCIG together with the proposed expansion of Union Pacific's adjacent intermodal

container transfer facility railyard and BNSF's existing Hobart railyard. The court also found serious deficiencies with the analysis of traffic and noise impacts.

This is a very damning finding and invalidates the use of the emissions reductions in the Tesoro Project Cumulative Impacts analysis.

Without the SCIG reductions, Table 5-2-2 emissions add up to: 646.97 lbs/day of VOCs, 825.15 lbs/day of CO, 832.01 lbs/day of NOx, 3.63 lbs/day of SOx, 340.46 of PM10, and 51.37 lbs/day of PM2.5:

Table 12: Cumulative Operational Emissions (lbs/day) are significant with the SCIG subtracted

	VOC	CO	NOx	SOx	PM10	PM2.5
6 ILWU Local 13 Dispatch Hall(b)	19.9	--	26.9	--	16.9	1.5
8 Valero Cogen(c)	33.4	201.8	0	0	95.8	20.6
9 WesPac(d)	-27	-266	-40	<1	-33	-30
10 LAUSD Span K-8 School(e)	8.76	--	--	--	--	--
12 Warren E&P(f)	19	14.4	20.5	--	3.7	4.3
15 Sepulveda/Panama Project(g)	339.1	546.9	521.6	2.82	203.9	32.4
16 Shell Revitalization Project(h)	50.83	0	0	0	0	0
21 Phillips 66 Crude Oil Storage(i)	166.8	109.1	249.4	0.3	18.9	12.8
22 Carson Facility E10 Project(j)	0	0	0	0	0	0
23 Carousel Tract(k)	30	200	50	0.48	32	9.1
32 CSULB Foundation Retail Project(l)	4.89	18.95	3.61	0.03	2.26	0.67
34 Tesoro LPG Recovery Unit	0.46	0	0	0	0	0
35 Tesoro Dehexanizer Unit	0.68	0	0	0	0	0
40 Tesoro Storage Tank 956	0.15	0	0	0	0	0
Total	**646.97**	**825.15**	**832.01**	**3.63**	**340.46**	**51.37**
Operational Significance Thresholds	55	550	55	150	150	55
Significant?	**Yes**	**Yes**	**Yes**	No	**Yes**	No

This shows large, significant Cumulative Impacts for VOCs, CO, NOx, and PM10 for the Project, even given the small estimations of emissions given for the Tesoro Project, without considering emissions underestimations discussed in other parts of this report. When additional underestimations discussed in this report are considered (such as SOx, PM2.5, and all pollutants from flares and heaters), then all criteria pollutants become significant.

[129] http://www.aqmd.gov/home/library/public-information/2016-news-archives/scig-win-pr

G1-81.95 cont'd.

Response G1-81.95

The comment is correct that a superior court recently set aside certification of the EIR for the Southern California International Gateway (SCIG) project, and accordingly the emission reductions associated with the SCIG project should not be considered in the environmental analysis of the proposed project. However, the invalidation of the SCIG EIR does not alter the analysis or conclusions in the DEIR because the SCIG emission reductions were not considered in the determination of cumulative impacts. Moreover, the DEIR disclosed the fact that the SCIG emission reductions were tentative and annotated the references to SCIG with a disclaimer that the SCIG environmental analysis "has been challenged and is being litigated" or is "subject to revision pending outcome of ongoing litigation." (see pages 5-17, 5-18, 5-20, and 5-23 of the DEIR). In the FEIR, references to SCIG emission calculations in Chapter 5 have been removed.

The conclusion in the DEIR that the operational emission impacts of the proposed project are not cumulatively significant did not rely upon the emission reductions reported in the SCIG EIR. The chart (Table 12) provided in the comment letter is not an accurate representation of the

information in the DEIR. The emissions from the cumulative projects were listed in Tables 5.2-1 and 5.2.-2 of the DEIR for informational purposes. But, the emissions are not summed (as Table 12 would suggest) in order to determine cumulative impacts. As explained in Master Response 16, consistent with SCAQMD's policy, the operational emissions of the proposed project are below significance thresholds for all pollutants and thus, are not considered cumulatively considerable. Accordingly, the removal of the SCIG project does not affect the cumulative impacts emissions findings of the DEIR for the proposed project.

Comment G1-81.96

B. Many Interrelated Projects and additional issues should be identified and evaluated

The Project is very complex, involving thousands of pages of permit applications, evaluations, and DEIR documents and appendices. While the AQMD provided much-appreciated extensions to the public comment period, there are still many areas of evaluation missing from the DEIR that I was unable to fully explore, but which have the potential for major impacts, or major cumulative impacts. The DEIR should provide information about these projects. G1-81.96

Numerous related Projects or projects which could cause significant cumulative and/or piecemealed impacts that were not evaluated in the DEIR:

1. **Pipelines, storage, and export of fuels to Los Angeles International Airport –** 16 miles of pipelines were described in the Tesoro Logistic SEC 10K filing:

   > "On November 12, 2015, we purchased crude oil and refined product storage and pipeline assets in Los Angeles, California (the "LA Storage and Handling Assets") from Tesoro, which included 97 crude oil, feedstock, and refined product storage tanks with combined capacity of 6.6 million barrels and a 50% fee interest in a 16-mile pipeline that transports jet fuel from Tesoro's Los Angeles refinery to the Los Angeles International Airport."[130]

   It appears that Tesoro terminal storage capacity is increasing significantly, and the DEIR should provide information about the cumulative impacts of this project for the region, and how the refinery project would provide fuels for the airport. (A different airport project was identified in cumulative impacts – the WesPac project, at p. 5-9)

2. **Additional modifications and/or inter-relation with Tesoro Logistics operations** (since Tesoro sold many facilities for gathering, moving, storing, and distributing petroleum inputs and products to Tesoro Logistics and since previously cited company literature identifies its ongoing plans to use synergies between Tesoro refining and Tesoro Logistics). G1-81.96 cont'd.

3. **Baselines and changes in sales of hydrogen from offsite companies such as Air Products (and any others) to the Tesoro refinery should be provided, to establish whether overall hydrogen use will increase.** Hydrogen used at oil refineries is generated using fossil fuels. The DEIR identifies many expanding areas where hydrogen is used (hydrocracking, hydrotreating, etc.), but also stated that since the FCCU would shut down, hydrogen use would decrease. However, no baseline for hydrogen use was provided. Hydrogen production is a high-energy process, and a major industry in the State of California. US EPA found that refinery hydrogen plants produce almost 6% of refinery's GHG emissions.[131] Importing of hydrogen from Air Products and

4. **An evaluation of the San Pedro butane storage tanks relation to the Tesoro Los Angeles Refinery Project is needed.** It has been stated that oil refineries including Tesoro use butane from this San Pedro site. Since Tesoro is increasing use of LPG (Liquefied Petroleum Gas such propane, butane, etc.) that it will be importing by rail, the DEIR should also identify potential cumulative impacts regarding Tesoro storage or use of butane from the San Pedro tanks, and whether this will change post-Project. Potential impacts from explosion risk in San Pedro related to piping, using, and storing materials

must be evaluated. Potential explosion risk at this site could devastate the local residences and cover a wide area.

A hazard assessment was performed for this facility, showing very large blast zone maps extending miles away from the facility in the event of catastrophic releases, for example due to earthquake. This assessment found:[132]

> In the event of unexpected release of butane from the Amerigas storage facility, a variety of accidental risks can occur, which include types of combustion (pool, flash, and jet fires) and types of overpressure explosions (overpressure in storage tank, BLEVE [Boiling Liquid Expanding Vapor Explosion], etc.). The worst case scenario of a large-scale release hazard is projected to occur during the night when population density of the nearest receptors is highest. Low wind velocity is considered, as this would cause a dense vapor cloud of evaporated butane to collect within the facility, producing a powerful blast wave upon ignition. The largest combustion incident is projected to occur, whereupon BLEVE will occur as the result of simultaneous tank failure due to catastrophic earthquake, creating an intense overpressure that would result in a large-scale explosion, projectile shrapnel, and fire radiation exposure.

G1-81.96 cont'd.

This site has garnered widespread community concern and prompted public hearings regarding safety.[133] One community member, Janet Gunter, testified at the AQMD hearing about the Tesoro Project relation to the San Pedro butane tanks. She provided the following information by email:[134]

> "Tesoro and Valero both have contracts with Plains/Rancho LPG *[formerly Amerigas]* to receive and send their butane by pipeline directly from those facilities. Apparently Valero taps into the Tesoro pipeline, which I am assuming comes from the Wilmington facility. During summer blend months, the excess butane is pushed to Rancho from Tesoro. Then during the Winter months, the needed butane to be blended back into the gasoline is returned to Tesoro, again via the pipeline. Because of the issue of liability, it is assumed that Tesoro has some kind of buy/sell agreement that waives them of liability in case of accident while being stored at Rancho. The Rancho LPG manager has stated publicly that this storage facility is an important part of the region's refining process due to the "inability" of these two refineries to store this excess butane on their own property. Congresswoman Hahn has acknowledged a number of times, that these facilities should be storing this butane on their own property."

CBE asked Tesoro representatives if Tesoro stores butane at the San Pedro tanks. Tesoro representatives stated that the refinery did not, but that Tesoro does sell LPG products at certain times of year to third parties in the area.[135]

G1-81.96 cont'd.

The DEIR should identify whether any parties (Tesoro or third parties) store or use LPG products that end up in these tanks, how this is transported (pipeline or other), volumes, and how this might change due to the Project.

[130] From Tesoro Logistics 2015 10-K, p. 8: http://services.corporate-ir.net/SEC.Enhanced/SecCapsule.aspx?c=242247&fid=14232449

[131] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry,* Oct 2010, https://www.epa.gov/sites/production/files/2015-12/documents/refineries.pdf

[132] *Quantitative Risk Analysis for Amerigas Butane Storage Facility, 2010, Prepared in Consideration of: Amerigas Propane L. P.,* 2110 North Gaffey Street San Pedro, CA 90731, Cornerstone Technologies, Inc., http://nwsanpedro.org/wp-content/uploads/2012/10/RISK-ANALYSIS-ON-TANKS-PDF2.pdf

[133] 9/11/2014, Donna Littlejohn, Daily Breeze, *Critics not satisfied by assurances that Rancho LPG storage tanks in San Pedro meets all federal standards,* http://www.dailybreeze.com/business/20140911/critics-not-satisfied-by-assurances-that-rancho-lpg-storage-tanks-in-san-pedro-meets-all-federal-standards , Attachment 47

[134] Email from Janet Gunter to Julia May, Senior Scientist, CBE, May 19, 2016, In a follow-up email, she reported that this information was as reported to her by Valero, PHMSA (Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation), and Janice Hahn, Rep. Janice Hahn, D-San Pedro

[135] 6/1/2016 meeting of CBE and Tesoro by telephone and webex presentation of Tesoro LARIC project.

Response G1-81.96

The Tesoro Logistics acquisition mentioned in item 1 of the comment is the transfer of assets from one Tesoro entity to another. Therefore, Tesoro did not expand its storage capacity, but merely changed the management structure of the existing storage tanks and pipelines. This management adjustment has no impact on the physical environment. Neither the acquisition nor the proposed project included or propose changes to the pipeline to LAX.

Item 2 mentioned in the comment provides no specific reference to Tesoro statements and no citations to topics analyzed in the DEIR. Without further information, no response is necessary under CEQA.

Item 3 in the comment addresses hydrogen use at the Refinery. Response G1-78.171 explains the hydrogen demand of the Refinery and the hydrogen production limitations. The Air Products Plant is the only third-party hydrogen supplier connected to the Refinery and, therefore, is the only third-party source of hydrogen for the Refinery. Because the Refinery is hydrogen limited and no additional hydrogen production facilities are proposed, no change in hydrogen production is expected from implementing the proposed project.

The Rancho LPG facility mentioned in item 4 of the comment is explained in Master Response 10. Tesoro does not own or store butane, propane, or LPG at the Rancho LPG facility. Master Response 10 also explains that the proposed project will reduce the excess LPG available for third-party sales, as a result of shutting down the Wilmington Operations FCCU.

As described above, none of the four items mentioned in the comment have provided evidence of significant impacts associated with the proposed project not disclosed in the DEIR. Therefore, no cumulative impacts are associated with the items mentioned in the comment and no piecemealing has occurred.

Comment G1-81.97

VII. The Environmental Justice setting and implications of all the above Project and Cumulative impacts require serious attention and compliance with AQMD and EPA policies

This Project Setting is proposed in an area of extreme industrialization, and a textbook case of environmental inequity. The DEIR is remiss in leaving out an Environmental Justice analysis for the Project. I have left discussion of this issue late in the report, in order to illustrate the specific harms of the Project first, but the context of the existing setting must not be underplayed, as is clearly illustrated in just the few examples below. The DEIR needs to pay this serious, detailed attention, because the Project is not occurring in isolation.

G1-81.97

If there was any doubt, in one example study, *Minding the Climate Gap*, academic researchers found that the BP Carson (now Tesoro Carson) and Tesoro Wilmington were both the top, and the second worst polluters in the entire state, in terms of *"Top 10 Facilities Polluting Disproportionately in Communities of Color"*. Specifically, the report analyzed the highest *"Pollution Disparity Index for PM10 at 2.5 Miles Across All Major GHG-Emitting Facilities"*.[136] The report also found half of the top ten list in the state was in the Wilmington/Carson area (all five of these are oil refineries), which impact Wilmington, Carson, Long Beach, and other communities:

Minding the Climate Gap **- Top 10 Facilities Polluting Disproportionately in Communities of Color (p. 7)**

Rank	Facility Name	City	Pollution Disparity Index
1	BP Carson Refinery	Carson	1.44
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)	1.01
3	Paramount Refinery	Paramount	0.62
4	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)	0.52
5	ExxonMobil Torrance Refinery	Torrance	0.40
6	Chevron Richmond Refinery	Richmond	0.32
7	Malburg Generating Station (Vernon Power Plant)	Vernon	0.31
8	ConocoPhillips Carson Refinery	Carson	0.29
9	Valero Wilmington Refinery	Wilmington (Los Angeles)	0.24
10	California Portland Cement Company Colton Plant	Colton	0.16

Minding the Gap provided this photo of Tesoro Wilmington air impacts during a 2009 accident:

Tesoro Wilmington Refinery, September 25, 2009

G1-81.97 cont'd.

(p.3)

There is an abundance of information about the concentration of petroleum and other toxic sources in this area. I compiled information in 2009 into a report to the community regarding the concentration of refining in Southern California and the state, showing Wilmington/Carson/Long Beach,[137] as the highest concentration of oil refining in the state, with almost a third of the state's capacity. (See for example, pages 3, 6, 14, and 15). The capacity of many individual refineries has probably increased since that time (possibly statewide), but the high concentration in Wilmington/Carson/Long Beach remains.

G1-81.97 cont'd.

[136] Minding the Climate Gap, 2009, Manuel Pastor, Ph.D., Rachel Morello-Frosch, Ph.D., MPH, James Sadd, Ph.D., Justin Scoggins, M.S, UC Berkeley, and USC Program for Environmental and Regional Equity, P. 7, available at: https://dornsife.usc.edu/assets/sites/242/docs/mindingthegap_executive_summary.pdf, Attachment 48

[137] The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean them Up, April 2009, *["California has a large oil refining capacity—over 2 million barrels per day (bpd) of crude oil refined in three regions. The largest refining capacity in the state is in the Los Angeles region (about 1.25 million bpd of crude oil refining), followed by the San Francisco Bay Area with about 860,000 bpd refining capacity, with another 150,000 bpd in the Center of California). Even a single small refinery is a major air pollution source. (See maps on the following pages.) • Wilmington/Carson in the LA region has the highest concentration of refineries in the state (about one third the state's capacity). About half Los Angeles' refining capacity is concentrated in the Wilmington/ Carson area (five refineries and about 650,000 bpd)."]* at p. 3, http://www.cbecal.org/wp-content/uploads/2012/05/wilmington_refineries_report.pdf

Response G1-81.97

The comment claims that the DEIR is remiss in leaving out an environmental justice analysis of the proposed project. The DEIR analysis evaluated impacts to residents surrounding the Refinery, irrespective of whether the residents are part of the environmental justice community. It should be noted that neither the CEQA Statutes nor Guidelines require an analysis of environmental justice impacts. Despite this, the SCAQMD has a strong record of addressing environmental justice issues in other forums. For example, the history of SCAQMD's Environmental Justice program began in 1997. Since that time, the SCAQMD has instituted a number of community initiatives to help improve air quality for low income residents and residents of color in the Basin. The programs and initiatives have been continually reviewed and updated to keep the environmental justice movement growing. One important component of the SCAQMD's review process is the EJAG), which serves as an advisory group to the SCAQMD Governing Board. The mission of EJAG is to advise and assist SCAQMD in protecting and improving public health in SCAQMD's most impacted communities through the reduction and prevention of air pollution.[279] As a result, the SCAQMD's Environmental Justice program goes beyond a single project, but instead encompasses a unified regional approach to reducing exposure to the Basin's most impacted communities. Master Response 14 explains environmental justice relative to the analysis of the proposed project in the DEIR.

The comment also claims that the context of the existing setting must not be underplayed. To support this claim, the comment provides information from a seven-year old study that explains racial disparity in exposure to PM10 emissions at the facility level. Chapter 3 of the DEIR includes comprehensive descriptions of the existing settings for all environmental topic areas evaluated in the DEIR. With regard to the existing air quality setting, the DEIR uses the years 2012 and 2013 as the baseline, which is more recent and, therefore, more accurate and representative of the existing setting for the proposed project than 2009 information. Thus, the existing setting is not underplayed and complies with all requirements in CEQA Guidelines § 15125 for establishing the environmental setting. See Master Response 12 for information on the Existing Setting (baseline) for the proposed project.

It should be noted that the claim in the comment that the BP Carson (now Carson Operations) and the Wilmington Operations were the top and second worst polluters in the state in the 2009 study cited refers to pollution disparity impact (PDI) which is not the same as total emissions.[280] PDI is a way showing the extent to which a facility, based on location, may disproportionately expose people of color compared to non-Hispanic whites to PM10 emissions at the facility level based on the population already living within certain distances of the facilities in question. The higher the population density the greater the PDI, which is one measure of environmental justice. Nonetheless, the PDI is not a measure of the amount of PM10 emissions from the Refinery. As

[279] For additional information on the SCAQMD's environmental justice policies see *Environmental Justice* at http://www.aqmd.gov/home/about/initiatives/environmental-justice.

[280] The citation in the comment refers to: Pastor, M. Ph.D.; Morello-Frosch, R., Ph.D., MPH; Sadd, J., Ph.D.; Scoggins, J. M.S. 2009. Minding the Climate Gap What's at Stake if California's Climate Law isn't Done Right and Right Away. https://dornsife.usc.edu/assets/sites/242/docs/mindingthegap_executive_summary.pdf.

explained in Section 4.2.2.2. of the DEIR, the proposed project will result in local reductions of PM10 emissions largely attributed to the shutdown of the Wilmington Operations FCCU.

The comment claims there is an abundance of information about the concentration of petroleum and other toxic sources in the vicinity of the proposed project. The SCAQMD has carried out four MATES analyses since the early 1990s.[281] The results of these analyses, especially the most recent analyses, MATES IV[282], show that cancer and non-cancer health risks have been declining Basin-wide, although the area surrounding the Ports of Long Beach and Los Angeles continue to have some of the highest risks. However, the MATES IV data indicate that 87 percent of the cancer risk in these areas is generated by mobile sources, both diesel and gasoline vehicles. Further, benzene emissions, which are emitted by a number of sources including refineries, represent four percent of the risk in these areas. Benzene concentrations in these areas, however, do not appear to be substantially different than other areas of the Basin. As a result, health effects from exposure to TACs have been declining and appear to be associated primarily with exposure to mobile source emissions rather than refinery emissions. For additional information see Master Response 3 and Section 3.2.4.5 of the DEIR.

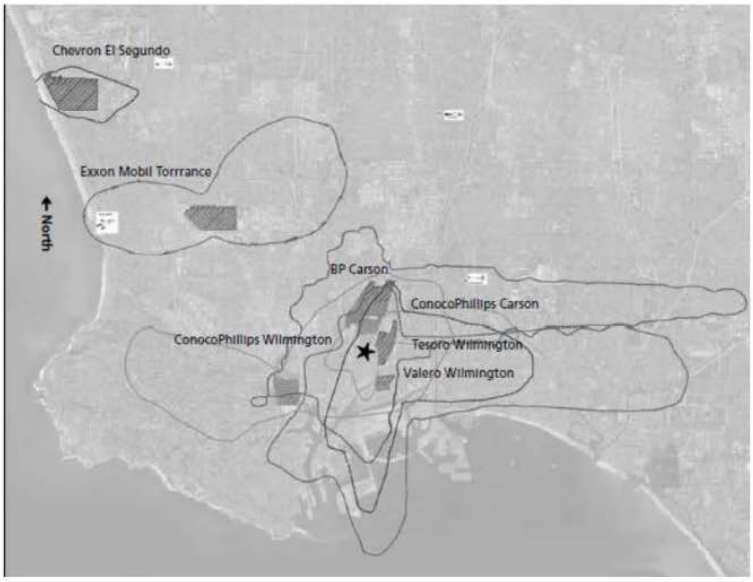
Finally, the comment claims that the capacity of many individual refineries has "probably" increased since 2009. The comment provides no data or other information to support this claim. Although the SCAQMD does not specifically regulate crude oil throughput, emission limits imposed on emission sources at refineries in the Basin through permit conditions enforced by SCAQMD staff act to limit crude oil throughput. Although the proposed project has the potential to increase crude oil capacity by 6,000 bbl/day associated with the Wilmington Operations DCU H-100 heater, this increase is analyzed throughout the DEIR. For additional information, see Master Response 6.

[281] For additional information on the SCAQMD's MATES analyses see *Health Studies* at http://www.aqmd.gov/home/library/air-quality-data-studies/health-studies.

[282] For additional information on the SCAQMD's MATES IV analysis, see *MATES IV Multiple Air Toxics Exposure Study* at http://www.aqmd.gov/home/library/air-quality-data-studies/health-studies/mates-iv.

Comment G1-81.98

At that time, the AQMD provided a map of oil refinery plumes in the South Coast (below and available in the Wilmington report), showing the overlapping plumes of 5 oil refineries impacting Wilmington, Carson, Long Beach, and further areas downwind (at p. 6):



I also summarized demographic data at the time for Wilmington showing this area is not only impacted by refineries, but two major ports, heavy, and expanding freeways, auto body shops, oil drilling, and more. It also showed that Wilmington is a community of color, and also a lower income area compared to the region.

G1-81.98

Five Oil Refineries	Oil Drilling
Ports of LA & Long Beach	Alameda Corridor (railway)
I-110 & 710 Freeways	Diesel Trucking
Auto Body Shops	Recycling Facilities
Sewage Treatment (& much more)	Regional Smog

Communities of color & the low income in Wilmington bear the cumulative impact burden of fossil fuel.[28]

	Wilmington	LA
Hispanic or Latino of any race	85%	45%
Median household income	$30,260	$42,190
Individuals below the poverty level	27%	18%

G1-81.98 cont'd.

I did not provide this information for Carson and Long Beach at the time. The DEIR should provide an updated analysis on the local demographics.

Response G1-81.98

The comment references a 2009 document[283] that compiled emissions data for refineries in California in 2009, including those located in the Basin. The comment claims that not only is the area impacted by refineries, but two major ports, heavy, and expanding freeways, auto body shops, oil drilling and more. As noted in Response G1-81. 97, MATES IV data indicates that 87 percent of the cancer risk in these areas is generated by mobile sources, both diesel and gasoline vehicles. So, although the area is an industrial area, the vast majority of TAC emissions is from mobile sources, not industrial facilities. For additional information see Master Response 3. Additionally, it should be noted that the proposed project will reduce local emissions of operational CO, NOx, SOx, PM10, PM2.5, and GHG. However, the DEIR analysis concluded that regionally, reductions of these pollutants are considered to be neutral.

The comment also claims that the DEIR should provide an updated analysis on local demographics. Because the comment references low income and people of color communities, it is assumed that this refers to an environmental justice analysis. With regard to preparing an environmental justice analysis in the DEIR, Response G1-81.97 explains why a specific environmental justice analysis was not included in the DEIR.

Comment G1-81.99

The DEIR did provide in the Cumulative Impacts chapter the following long list of many other major projects in the area (at p. 5-20):

TABLE 5.2-3

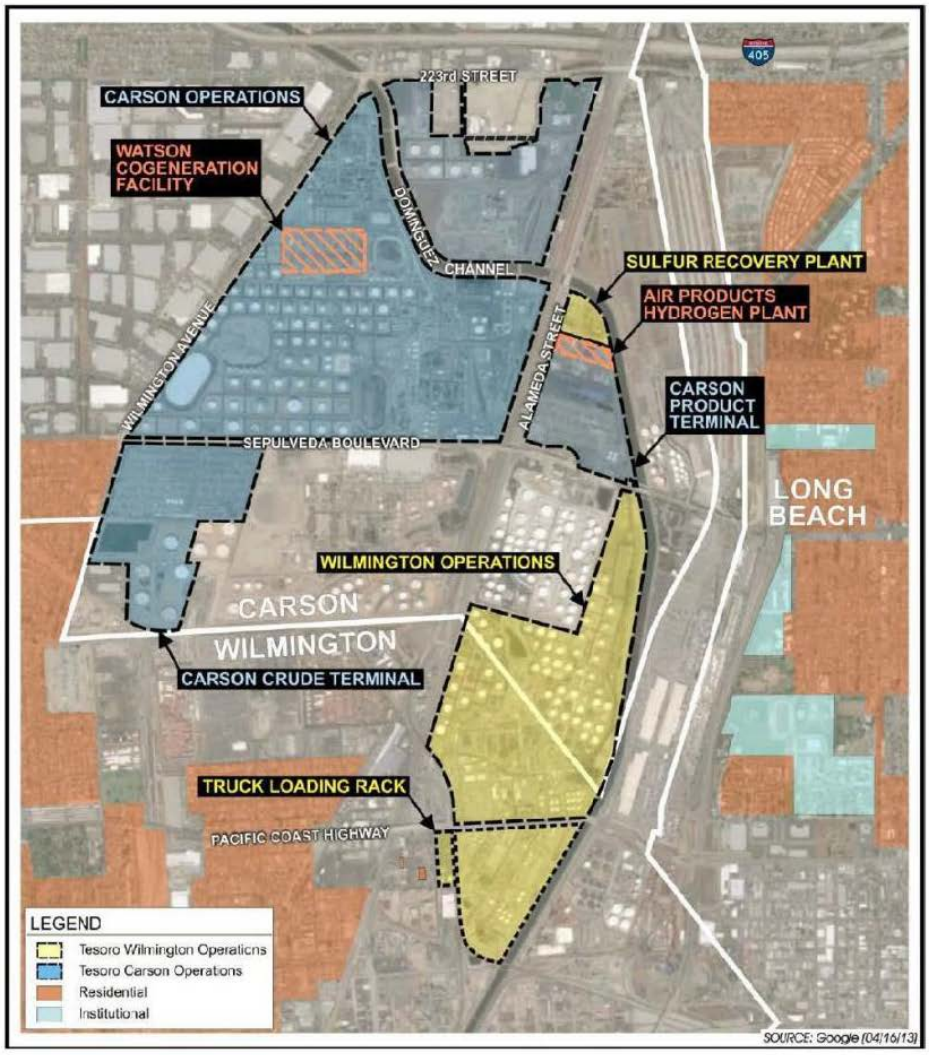
Cumulative Health Risk Assessment Results Associated with Exposure to Toxic Air Contaminant Emissions

No.	Cumulative Project	MEIR	MEIW	Chronic Hazard Index	Acute Hazard Index
4	Southern California International Gateway Project[a]	-160×10^{-6}	-114×10^{-6}	0.11	0.13
6	ILWU Local 13 Dispatch Hall[b]	NS	NS	--	--
8	Valero Cogen[c]	0.57×10^{-6}	0.33×10^{-6}	0.024	0.019
12	Warren E&P[d]	0.4×10^{-6}	0.05×10^{-6}	0.0007	0.014
16	Shell Revitalization Project[e]	8.90×10^{-6}	7.20×10^{-6}	0.022	0.105
21	Phillips 66 Crude Oil Storage[f]	0.13×10^{-6}	0.13×10^{-6}	0.0005	0.0015
22	Shell Carson Facility E10 Project[g]	2.11×10^{-6}	1.55×10^{-6}	0.0196	0.002
23	Carousel Tract[h]	0.81×10^{-6}	0.09×10^{-6}	0.01	0.01
32	CSULB Foundation Retail Project[i]	0.16×10^{-6}		0.001	NA

The DEIR did provide the following map, showing residences in close proximity, surrounding the two refineries, although a larger map would show additional impacted residences:

G1-81.99

[283] May, J. 2009. The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean Them Up! http://www.cbecal.org/wp-content/uploads/2012/05/wilmington_refineries_report.pdf.



This community requires serious attention regarding air pollution and hazards. The communities of Wilmington, Carson, and Long Beach are proud communities, with a richness of culture and community strength, in addition to carrying this extreme burden of heavy industry. Providing an Environmental Justice analysis is consistent with AQMD and EPA policies, and should be part of the DEIR.

G1-81.99 cont'd.

Response G1-81.99

The comment identifies the major projects analyzed in the cumulative impacts chapter contained in Table 5.2-3 of the DEIR. No issues are identified so no further comment is necessary under CEQA.

The comment reproduces Figure 2-2 from the DEIR and states that a larger map would show additional impacted residences. Figure 2-2 along with Figure 2-1 comply with CEQA Guidelines § 15124(a), which states, "The precise location and boundaries of the proposed project shall be shown on a detailed map, preferably topographic. The location of the project shall also appear on a regional map." For maps that show areas outside the boundaries of the

Refinery that are adversely affected by the proposed project, refer to Chapter 4. See for example Figures 4.3-1, 4.3-2, and 4.3-3.

As claimed in the comment, the community requires serious attention regarding air pollution and hazards. Sections 4.2 and 4.3 of the FEIR include comprehensive quantitative and robust analyses of air quality and hazard impact analyses, respectively. Please refer to these sections for addition information on the air quality and hazards analyses prepared for the proposed project.

The comment claims that providing an environmental justice analysis is consistent with SCAQMD and U.S. EPA policies. The comment, however, does not identify any specific SCAQMD or U.S. EPA environmental justice policies or deficiencies in the DEIR. The SCAQMD does not have a policy requiring an environmental justice analysis in a CEQA document for a permit project. Response G1-81.97 provides additional information on SCAQMD environmental justice policies. U.S. EPA's environmental justice policies refer to incorporating environmental justice goals into U.S. EPA's preparation of EISs and Environmental Assessments (EAs) under the National Environmental Policy Act (NEPA).[284] The proposed project is not subject to NEPA and the environmental analysis document is neither an EIS nor an EA. Therefore, neither the proposed project nor the EIR is subject to U.S. EPA policies. Master Response 14 explains environmental justice relative to the analysis of the proposed project in the DEIR.

Comment G1-81.100

VIII. Recommendations and Alternatives

In order to evaluate the potential Project impacts, the DEIR should provide the baseline data and evaluations described above in this report. As a partial summary, it should include the following information:

G1-81.100

Response G1-81.100

The comment is an introduction to the Recommendations and Alternatives section of the comment letter and does not require a response. Responses G1-81.1 through G1-81.99 address all the issues raised, including the suggestions that additional baseline data and evaluations are required.

[284] For additional information on U.S. EPA's environmental justice policies relative to NEPA, refer to *Environmental Justice and National Environmental Policy Act* at https://www.epa.gov/environmental justice/environmental-justice-and-national-environmental-policy-act.

Comment G1-81.101

Baseline data and projected changes for the following:

Crude Oil:

- **The crude oil slate** baseline of each refinery for at least the past 5 years, including the specific crude oil geographic origin, API gravity, H2S percent and total sulfur percent, TAN, metal content, benzene percent, and paraffinic content, in addition to projected changes, for both domestic and imported crude oil;

G1-81.101

Response G1-81.101

As described in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and the proposed project is not designed to facilitate a change in the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend. Master Response 4 further describes that the crude oils are blended to stay within a consistent range of properties due to the processing constraints of the Refinery. Additionally, Response G1-78.94 provides a table where additional responses to Comment Letter 78 address the crude oil properties listed in Comment G1-81.100.

Master Response 2 clarifies that specific data regarding crude oil blends processed by the Refinery are trade secret, confidential business information. Because the data are trade secret and no modifications are proposed to enable a significant change in the crude oil blend processed at the Refinery, baseline crude oil data were not relied upon or used in the DEIR analysis and need not be provided.

Comment G1-81.102

- **Total crude oil throughput** baseline data at each refinery for the past 5 years and projected changes, clarifying the discrepancy between the DEIR figures of 363,000, plus potentially 6,000 bbls/day, as compared to the Tesoro website figure of 380,000, and projected changes; and distillation unit throughput baseline and projected changes,

G1-81.102

Response G1-81.102

Master Response 5 describes explains the difference in the 363,000 bbl/day Refinery crude oil capacity stated in the DEIR and the 380,000 bbl/day capacity recently reported in SEC filings and on Tesoro's website. Master Response 5 also addresses the adequacy of the DEIR's analysis of the environmental impacts of crude oil capacity changes which may result from the proposed project.

Master Response 2 clarifies that specific data regarding crude oil blends processed by the Refinery are trade secret, confidential business information. Because the data are trade secret and no modifications are proposed to enable a significant change in the crude oil blend processed at the Refinery, baseline crude oil data were not relied upon or used in the DEIR analysis and need not be provided.

Comment G1-81.103

- **The crude oil storage** baseline including total existing volume at each refinery, the total existing throughput, and the specific crude oils stored in each tank for at least the last year, in addition to projected changes. G1-81.103

Response G1-81.103

Previous responses have addressed in detail the existing crude oil storage volume and capacity at the Refinery (see Responses G1-78.126 and G1-78.128).

Master Response 2 clarifies that specific data regarding crude oils processed by the Refinery are trade secret, confidential business information. Because the data are trade secret and no modifications are proposed to enable a significant change in the crude oil blend processed at the Refinery, baseline crude oil data were not relied on or provided to the SCAQMD, and need not be provided.

Comment G1-81.104

Others:

- **Sales of fuels within California,** outside California to other states, and outside the U.S., baseline and projected changes, and the percent of baseline and future projected fuels sales that already meet California low sulfur fuels standards, and what percent would instead meet federal Tier 3 standards; G1-81.104

Response G1-81.104

The comment duplicates points made in Comment G1-81.38. Response G1-81.38 explains that throughput or production data were not relied on to evaluate the impacts of the proposed project in the DEIR. Also, as explained in Master Response 2, Tesoro's fuel production and sales data are trade secret, confidential information. Therefore, baseline and projected fuel production and sales data were not relied on or provided to the SCAQMD and need not be provided.

Comment G1-81.105

- **Desulfurization capacity,** baseline and projected changes; G1-81.105

Response G1-81.105

Master Response 4 and Response G1-81.31 address the SRP capacity and the fact that the Refinery operates at or near the SRP capacity. It is important to understand that since no modifications to the SRPs are included in the proposed project, the actual sulfur removal capacity of the Refinery will not change as a result of the proposed project because the SRP is downstream of the hydrotreating (desulfurization) units. Therefore, the proposed project is not designed to, and the Refinery cannot accommodate, a change in the range of sulfur allowed in the crude oil blend processed by the Refinery.

The proposed hydrotreater project modifications are focused on the Tier 3 gasoline specification that is changing. While there are project elements that will increase sulfur removal from distillates and gasoline blending components, the volume of gas oil requiring sulfur removal will be reduced. As explained in Response G1-81.31, the reduced gas oil hydrotreating offsets the additional distillate and gasoline blend stock hydrotreating, and the sulfur removal capacity of the Refinery is limited by the capacity of the SRPs, which are downstream of the hydrotreaters.

Comment G1-81.106

- **Mass of sulfur processed in each refinery** (baseline for the last 3-5 years, and projected changes); G1-81.106

Response G1-81.106

The comment is addressed in Response G1-81.105.

Comment G1-81.107

- **Emissions for DCU Heater H-100** and other project heaters, including criteria pollutants, toxics, and greenhouse gases baseline daily and annual emissions. G1-81.107

Response G1-81.107

The comment is addressed in Responses G1-81.79 and G1-81.81. The FEIR evaluated daily criteria pollutant emissions from heaters and other project components in Section 4.2.2.2, daily and annual TAC emissions in Section 4.2.2, annual GHG emissions in Section 5.2.2, detailed emissions in Appendix B-3, and health risk impacts in Appendix B-4. No additional analysis is required.

Comment G1-81.108

- **Hydrogen purchase** baseline and projected changes. G1-81.108

Response G1-81.108

The comment is addressed in Response G1-81.96. No additional hydrogen is available for purchase, the Refinery operations are hydrogen limited, and the proposed project does not alter the ability to produce hydrogen. Therefore, no hydrogen purchase analysis is needed.

Comment G1-81.109

- **LPG, butane, propane** storage at San Pedro tanks and projected changes, and sales to third parties storing these materials; G1-81.109

Response G1-81.109

The comment is briefly addressed in Response G1-81.96 and in detail in Master Response 10. The proposed project does not involve the Rancho LPG facility.

Comment G1-81.110

- **Marine terminals crude delivery characteristics, ship size and projected changes** G1-81.110

Response G1-81.110

Responses G1-78.176, G1-78.183, and G1-78.184 discuss the marine terminal analysis that was presented on pages 4-26 through 4-29 of the DEIR. Master Response 6 also explains marine deliveries and marine vessel emission reductions expected from the proposed project based on recent operations. While marine vessel emissions will be reduced as a result of the proposed project, the DEIR conservatively did not include marine vessel emission reductions in the CEQA significance determination. The emission reductions are difficult to predict with certainty since type/size and number of marine vessels that will visit the marine terminals post-project is independent of the proposed project, is dependent upon the type of vessel the ocean carrier chooses in which to transport the crude oil, and the number of each type of vessel arriving in a given year is speculative.

Comment G1-81.111

The DEIR should evaluate the following:

- A complete Environmental Justice evaluation of the human and environmental setting, and potential increased burden due to the additional impacts listed below G1-81.111

Response G1-81.111

The comment is addressed in Response G1-81.97 and Master Response 14.

Comment G1-81.112

- The potential that additional crude oil storage tank volume, throughput, and permit limits accommodate different crude oils, especially Bakken and Canadian crudes. — G1-81.112
- The refinery's potential to replace Alaskan crude with Bakken.
- The potential for increased BTEX presence and other negative impacts in the refinery due to replacement of Alaskan crude with Bakken.
- The refinery potential to mix Bakken and Canadian crude to approximate Alaskan crude.
- The refinery potential to replace California crudes with Canadian tar sands crudes.
- An evaluation of the well to wheel GHG and other emissions due to a substantial switch to Bakken crude oils above the baseline at the refinery. — G1-81.112 cont'd.
- An evaluation of the well to wheel GHG and other emissions due to introduction of significantly increased volumes above the baseline of Canadian crude oils at the refinery.
- Potential increased corrosion, explosion risk, benzene, H2S, and other toxic components of crude oil, increased processing hazards due to paraffinic crudes, increased GHGs due to replacing some heavy crudes with heavier crudes including Canadian.
- Potential impacts out of state due to importing Bakken crude oil to new Tesoro LA storage tanks, including GHGs and transportation risks.

Response G1-81.112

The issues raised in the comment have been explained previously. The comments are brief and summary in nature. Detailed responses to the topics raised can be found in the responses listed in Table 81.112-1. As explained in the detailed responses, the DEIR fully analyzed the proposed project and no further analysis is needed.

Additionally, regarding the requests to provide information about environmental impacts of Bakken and heavy Canadian crude oil *production and transportation* (i.e., including so-called "well to wheel greenhouse gas and other emissions), such analysis is not required by CEQA because the proposed project will have no effect on demand for those crude oils. A lead agency need only evaluate "direct physical changes in the environment which may be caused by the project and reasonably foreseeable indirect physical changes in the environment which may be caused by the project." (CEQA Guidelines § 15064(d)) The comment suggests that as a result of the increased storage capacity and/or changing of types of crude oils refined at the Refinery associated with the proposed project, there will be environmental impacts elsewhere (in North Dakota and Canada) where the Refinery's demand for more Bakken and heavy Canadian crude oil will increase production of these crude oils. The proposed project does not directly affect or result in changes to oil production methods or transportation. CEQA only requires consideration of indirect physical changes "if that change is a reasonably foreseeable impact which may be caused by the project." (CEQA Guidelines § 15064(d)(3).) "A change which is speculative or unlikely to occur is not reasonably foreseeable." (CEQA Guidelines § 15064(d)(3).)

It is not reasonably foreseeable that the proposed project will cause environmental impacts related to the production of Bakken and heavy Canadian crude oils because the proposed project will have no effect on demand for these goods. The crude oil slate at the Refinery will not change as a result of the proposed project and the Refinery will continue to utilize crude oil consistent with the regulatory constraints on the Refinery. See Master Response 4. The

construction of new storage tanks will not increase or alter the Refinery's demand for crude oils because the tanks are being constructed to increase crude oil unloading efficiency from marine vessels delivering crude oil to be used at the Refinery. Tesoro will not import and store crude oils that will not fit its crude oil operating envelope, and will not import and store substantially more crude oil because the Refinery's crude oil capacity will not increase beyond the slight 6,000 bbl/day increase analyzed in the DEIR. In addition, as shown in Table 81.112-1, Responses G1-81.37, G1-81.57, G1-81.59, and G1-78.150 explain that Bakken or heavy Canadian crude oils are not replacements for ANS or California crude oils.

Table 81.112-1

Topics Raised in Comments and Location of Responses

Topic	Response	
	Master Response Number	Specific Response Number
Crude Oil Blend Remains Unchanged	4	G1-81.36 and G1-78.94
Proposed Crude Oil Storage Tanks for Maine Vessel Unloading	6	G1-81.39
Bakken Not a Replacement for ANS	-	G1-81.57
Bakken Crude Oil H_2S	-	G1-81.58
Canadian Crude Oil Hazards and Emissions	-	G1-81.59 through G1-81.63
Bakken and Heavy Canadian Crude Oil Blend not a Replacement for ANS	-	G1-81.37 and G1-78.150
Heavy Canadian Crude Oil Not a Replacement for CA Crude Oil	-	G1-81.59
GHG Emissions Fully Analyzed	-	G1-81.65 and G1-81.67
Crude Oil Properties	-	G1-81.53 through G1-81.63

Note: - = No Master Response prepared on this topic.

Comment G1-81.113

- The Project potential to increase to the total refinery crude oil throughput, distillation unit, coker throughput, and other unit increases, due to the current lack of clarity on the exact refinery capacity and actual baseline throughput.] G1-81.113

Response G1-81.113

Master Response 5 explains the difference in the 363,000 bbl/day Refinery crude oil capacity stated in the DEIR and the 380,000 bbl/day capacity recently reported in SEC filings and on Tesoro's website.

Master Response 2 clarifies that specific data regarding crude oil blends processed by the Refinery are trade secret, confidential business information. Because the data are trade secret

and no modifications are proposed to enable a significant change in the crude oil blend processed at the Refinery, baseline crude oil data were not relied on or provided to the SCAQMD, and need not be provided.

Master Response 5 also addresses the adequacy of the DEIR's analysis of the environmental impacts of crude oil capacity changes which may result from the proposed project. Therefore, the DEIR fully assessed the potential impact of the proposed project and no further analysis is required.

Comment G1-81.114

- The potential that additional desulfurization may accommodate additional Canadian crude oil.
- The potential increase in the overall mass of H2S at the refinery due to additional desulfurization.

G1-81.114

Response G1-81.114

Master Response 4 explains the sulfur processing capacity at the Refinery and that the proposed project will not enable a change in the types of crude oil processed, the crude oil blend processed by the Refinery or the crude oil operating envelope of the Refinery.

As described in Response G1-81.38, the Refinery has limited ability to increase the amount of heavy Canadian crude oils that can be blended for processing. Therefore, no further analysis is required.

Comment G1-81.115

- GHG emissions of third parties due to importing additional hydrogen to the refinery.

G1-81.115

Response G1-81.115

As described in Responses G1-81.96 and G1-78.171, no additional hydrogen is available for purchase or production. Therefore, no additional GHG emissions could occur and no additional analysis is required.

Comment G1-81.116

- The potential for additional hazards at the San Pedro storage tanks, due to increased use of LPG at the refinery

G1-81.116

Response G1-81.116

As explained in Response G1-81.96 and Master Response 10, Tesoro does not own or store butane, propane, or LPG at the Rancho LPG facility. Master Response 10 also explains that the proposed project will reduce the excess LPG available for third-party sales, as a result of shutting down the Wilmington Operations FCCU.

Comment G1-81.117

- Hazards due to spills and accidents from ships due to crude oil changes G1-81.117

Response G1-81.117

As described in Master Response 4, the proposed project does not enable a change in the types of crude oil processed at the Refinery. The Refinery has historically processed crude oils from around the world, including North American crude oils such as Bakken and Canadian crude oils. As described on pages 4-26 through 4-29 of the DEIR, the size of marine vessels that can be received at the Long Beach Marine Terminal is limited to Panamax and Aframax and the proposed project does not change that limitation. Additionally, the proposed project would reduce anchorage between offloading events at Marine Terminal 1 and does not modify unloading operations. Therefore, the hazards associated with marine vessels are the same after implementation of the proposed project as the existing conditions and no further analysis is required.

Comment G1-81.118

- Interconnection and cumulative impacts of the Tesoro LA refinery with other Tesoro facilities in the region that transfer petroleum materials, including Tesoro Logistics and others G1-81.118

Response G1-81.118

The proposed project includes the installation of interconnecting piping to further connect the Carson and Wilmington Operations to operate as a single refinery. The Carson and Wilmington Operations crude oil and products distribution systems have always been connected because they are connected to the same third-party terminals via existing pipelines. After Tesoro's acquisition of Carson Operations in 2013, access to this connectivity was utilized. The environmental impacts of the proposed project pipelines were evaluated in Chapter 4 of the DEIR.

The DEIR analyzed cumulative projects in Chapter 5 and specifically included the Wespac pipeline project (see Table 5.1-1 No. 9 of the DEIR), which is unrelated to the proposed project.

Comment G1-81.119

- The status of the 42-inch pipeline expansion from the marine terminal to the storage tanks, described in the Tesoro 2014 Negative Declaration G1-81.119

Response G1-81.119

As explained in Response G1-81.89, the 42-inch pipeline that was part of the previous Draft Negative Declaration was not a marine terminal pipeline replacement as claimed in the comment. The proposed pipeline replacement was within the Wilmington Operations to replace the existing 12-inch pipeline that connects to the existing 24-inch marine terminal pipeline. The pipeline replacement described in the withdrawn Negative Declaration was sized up to 42-inches in

diameter. Further engineering determined that only a 24-inch pipeline was needed. Accordingly, a 24-inch pipeline to replace the 12-inch pipeline was included in the DEIR. Therefore, no additional analysis is required.

Comment G1-81.120

- Identification of cumulative potential impacts from underground petroleum pipelines and storage tanks controlled by Tesoro and Tesoro Logistics, and the regional petroleum industry, in the event of earthquakes and related fires.] G1-81.120

Response G1-81.120

With the exception of the interconnecting pipelines described in Section 2.7.3.1, the proposed project does not modify facilities outside the Refinery and the Carson Crude Terminal. The existing pipelines and storage tanks in the Basin are considered existing conditions. Since there are no identified projects at these facilities (see Table 5.1-1 of the DIER), and the comment provides no evidence of cumulative projects, these facilities are not considered as cumulative projects. A cumulative pipeline project proposed by Westpac (#9) was identified and analyzed in the cumulative analysis, including the cumulative hazards analysis in Section 5.2.3 of the FEIR. No significant cumulative impact related to hazards was identified.

As explained in Master Response 9, the worst-case consequence hazard analysis is not based on any single accident scenario, but evaluates the effect of a release no matter the cause. Therefore, earthquake generated upsets have been analyzed in the DEIR (see Sections 3.3, 4.3, and 5.2.3 of the FEIR).

Comment G1-81.121

Additional Alternatives to the Project pooling public recommendations on safety and lower emissions should be evaluated, including: G1-81.121

Because of extensive deficiencies in the DEIR, and the potential for significant harms due to the Project, an alternative outlined as follows should be added. Because the DEIR defines the objectives of the Project to be basically to build the units identified as the Project, it is not possible to propose an environmentally preferred alternative that meets the Project objectives. The DEIR has set up a self-supporting description in this way, so that only building the identified Project components can be found consistent with the objective of building the identified Project components (a circular argument).

This should be corrected, or as an alternative, the following could be considered as a hybrid between a No Project alternative, and an environmentally preferred alternative which meets some of the Project objectives (such as reducing emissions), but either way should be considered.

This environmentally preferred alternative should be evaluated, including at least the following means to eliminate Project impacts: G1-81.121 cont'd.

- No increased refinery crude oil throughput above an established, publicly available baseline (by permit),
- No storage tank expansions,
- No Bakken or Canadian crude oil in the refinery above baseline levels, set by a permit condition,
- No increased hazards and no increases in explosive and acutely hazardous materials use (including at least LPG sources, new railcar transfers, H2S, the Sulfuric Acid Regeneration Plant, Wet Jet Treater, and hydrotreaters).
- Additional emissions reductions in the refinery to offset or prevent potential increases from flaring, heaters, the crude oil switch, and all sources.
- Evaluation of funding for local zero carbon alternative energy mitigation measures, for example, those included in the 2014 Chevron Modernization Project Revised DEIR,

Response G1-81.121

The comment states that the manner in which the DEIR defines the objectives of the proposed project precluded effective alternatives analysis because the DEIR defined its objectives as building the particular units identified in the proposed project, rendering the analysis "circular" or "self-supporting." However, the objectives of the proposed project are not defined in the narrow manner characterized by the comment. The objectives are listed in the DEIR on pages 2-3 to 2-4 in the Project Description chapter and again on pages 6-1 to 6-2 in the Project Alternatives chapter. The DEIR first states each general objective of the proposed project then explains the specific way by which the proposed project will achieve each objective, but the subsequent explanatory phrases are not intended as the objectives themselves. The general objectives are:

- Improving process efficiency through integration while maintaining the overall production capability of transportation fuels.
- Recovering and upgrading distillate range materials from FCCU feeds.
- Complying with federal, state, and local rules and regulations.
- Improving financial viability for the newly integrated Tesoro Los Angeles Refinery and the local community.

- Integrating Carson and Wilmington Operations.
- Increasing overall Refinery processing efficiency.
- Improving efficiency of water-borne crude oil receipt and marine vessel unloading.

Contrary to the suggestion in the comment, these objectives are not to build the particular units called for in the proposed project. Consistent with the general objectives, the alternatives analysis in the DEIR evaluates alternatives in which different units are installed at the Refinery in order to accomplish objectives such as recovering and upgrading distillate range materials from FCCU feed or complying with applicable rules and regulations. (See DEIR Alternatives 2 and 3, pages 6-5 through 6-7). The DEIR concluded that both Alternative 2 and Alternative 3 would achieve most of the objectives of the proposed project, but determined that they were not environmentally superior to the proposed project (see pages 6-51 to 6-50 of the DEIR).

The comment proposes that the DEIR consider a "hybrid" alternative which only meets *some* of the proposed project objectives. CEQA only requires consideration of alternatives "which would feasibly attain most of the basic objectives of the project."[285] An "EIR [i]s not required to analyze the effects of a project that [the proponent] did not propose, or to analyze the effects of an alternative that would not feasibly attain most of the basic objectives of the project."[286] The Supreme Court has upheld alternatives analysis that did not include any alternatives which would not meet all project objectives because the agency reasoned that all objectives were necessary to achieve the project's fundamental purpose.[287] It is well-settled that "[a]n EIR need not consider every conceivable alternative to a project or alternatives that are infeasible."[288]

The comment does not identify the impacts which the offered alternative would mitigate. The DEIR appropriately analyzed project alternatives by describing "a range of reasonable alternatives to the project . . . which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project[.]"[289] Long-term operational air quality impacts are not expected to be adverse, and indeed would provide beneficial local air quality impacts by reducing overall localized emissions of operational CO, NOx, and SOx, as well as GHG emissions. Therefore, the proposed project is not expected to have long-term adverse environmental impacts on air quality. Accordingly, there was no need to analyze alternatives incorporating zero carbon alternative energy mitigation measures, or the other modifications that the comment states should have been analyzed.

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[285] CEQA Guidelines, § 15126.6(a).

[286] *Sierra Club v. County of Napa* (2004) 121 Cal.App.4th 1490, 1509 (holding that the EIR did not need to consider a suggested alternative that did not meet the "specific objective of putting vineyards on the site and irrigating them with wastewater resulting from its operations".

[287] *In re Bay-Delta Programmatic Environmental Impact Report Coordinated Proceedings* (2008) 43 Cal.4th 1143, 1165-1166 (The agency "determined that the four primary project objectives had to be addressed concurrently in an integrated manner if the project was to be successful and therefore feasible . . . Although a lead agency may not give a project's purpose an artificially narrow definition, a lead agency may structure its EIR alternatives analysis around a reasonable definition of underlying purpose and need not study alternatives that cannot achieve that basic goal.")

[288] *Bay-Delta*, 43 Cal.4th at 1163.

[289] CEQA Guidelines, § 15126.6(a).

It should be noted that Mitigation Measure A-9 (see page 4-41 of the DEIR) proposes mitigation to offset a substantial portion of the short-term construction emissions that will be generated.

Further, the DEIR was not required to analyze an alternative like the one described in the comment because it fails to meet many of the proposed project's objectives, and thus is not feasible. By precluding storage tank expansion, construction of a Sulfuric Acid Regeneration Plant to regenerate sulfuric acid on-site, addition of a Wet Jet Treater to improve jet fuel quality, and the upgrading of existing LPG rail facilities to enable fast unloading of railcars, the suggested alternative would not attain two of the proposed project's fundamental objectives—improving the efficiency of water-borne crude oil receipt and marine vessel unloading and increasing overall Refinery processing efficiency. The comment does not specify other ways in which those objectives would be achieved in the suggested alternative; instead, it proposes that the DEIR should have entirely foregone the objectives associated with these project components and considered a project alternative meeting only "some" objectives. As explained above, CEQA does not require that analysis.

Comment G1-81.122

On this last point, the Tesoro DEIR should evaluate the zero carbon mitigation measures identified in the 2014 Chevron Richmond Modernization Project Revised Draft Environmental (RDEIR). Many examples were included in the 2014 Chevron Modernization Project Revised DEIR (RDEIR) after the initial Chevron DEIR was rejected by the court due to its failure to account for changes to the crude oil slate, and was then extensively re-written.[138]

Although the Chevron RDEIR still contained deficiencies outlined in public comment, it nevertheless identified a whole class of local alternative energy mitigation for air pollution increases (both GHGs and co-pollutants) that are not present in the Tesoro LARIC DEIR. This included a fair amount of good information on innovative Community-Based Greenhouse Gas Reduction Programs (CGRPs), in line with ideas proposed by the community concerns that would move toward changing the local energy infrastructure toward inherently cleaner and safer systems is necessary. The RDEIR however was limited in its proposals to carry out the identified mitigation, and can be improved upon, but Chevron did identify millions of dollars in funding for developing these zero carbon community programs. The Chevron RDEIR unfortunately stated that CGRP reductions were just examples, and if not carried out, they would be replaced with cap-and-trade allowances (which are not local, and not reliable reductions). An environmentally superior alternative project would provide firm, specific, local reduction commitments at higher levels while improving the local economy. G1-81.122

Attached are my comments on the Chevron RDEIR zero carbon refinery emission mitigation measures, which identifies many of these mitigation measures, references the full Chevron report, and identifies improvements to ensure implementation.[139] G1-81.122 cont'd.

[138] Chevron Richmond Refinery Proposed Revised Project City of Richmond Planning Department File PLN11, May 2, 2014, Full RDEIR through City of Richmond, CA, links to this RDEIR may no longer be current at the City of Richmond website; excerpts are provided as Attachment 49, and should be available by request at the City, or by request to CBE.

[139] Comments on the Chevron RDEIR: A Feasible Alternative to the Project would provide firm, specific, local Greenhouse Gas Reductions, and this would be Environmentally Superior, Regarding the Chevron Richmond Refinery Proposed Revised Project, City of Richmond Planning Department File PLN11, May 2, 2014, Julia E May, CBE, which was attached to CBE comments on the Project, Attachment 50

Response G1-81.122

The comment suggests mitigation measures to reduce GHG impacts: "zero carbon mitigation measures identified in the 2014 Chevron Richmond Modernization Project Revised DEIR." The comment states that the Chevron RDEIR identified a class of local alternative energy mitigation for air pollution increases (both GHGs and co-pollutants) that are not present in the proposed project's DEIR, cross-references Chevron documents, and urges the DEIR to include these measures and to go beyond Chevron's contemplative approach to the measures and commit to developing them.

Mitigation measures to reduce GHG impacts are not required because the proposed project will reduce rather than increase GHG emissions. "[T]he proposed project is expected to result in local GHG emission reduction of approximately 66,139 metric tons per year, providing a net GHG emission reduction from the Refinery, thus, reducing the Refinery's contribution to global climate change (see pages 4-7 and 5-26 of the DEIR)." GHG impacts were analyzed in Chapter 5 of the DEIR, and because the proposed project will reduce GHG emissions, the DEIR appropriately concluded that the proposed project's contribution to GHG impacts is not cumulatively considerable (see pages 5-26 to 5-27 of the DEIR). Thus, as explained in the DEIR, "[m]itigation measures are not required because GHG emissions from the proposed project are not considered to be cumulatively considerable and, therefore, would not contribute to an existing cumulative significant impact for GHG emissions from other cumulative projects." (see page 5-27 of the DEIR). Accordingly, the particular mitigation measures proposed by the comment that were explained for a different project (the 2014 Chevron Richmond Modernization Project) with different impacts in need of mitigation are not relevant to the analysis of the proposed project.

Additional Submittal December 9, 2016

TESORO REFINERY INTEGRATION & EXPANSION
- Merging Tesoro Wilmington & former BP refinery next door

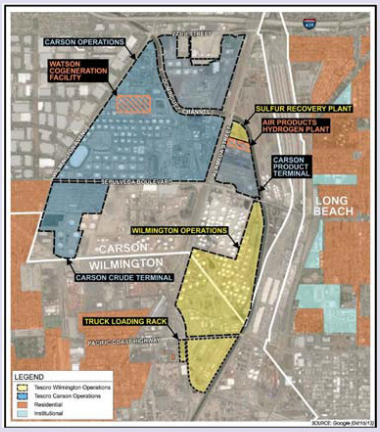
PRESENTATION BY CBE

(COMMUNITIES FOR A BETTER ENVIRONMENT)

DEC 2016

Project merges & expands former BP Carson with Tesoro Wilmington;
Would become largest refinery on West Coast with impacts in LA & Northern U.S.

- **Extensive additions**
  - -Closing Wilm. cracking unit, but expanding Carson's
  - -6 heater shutdowns, but 22 heater expansions
  - -New LPG rail delivery (Liquefied Petroleum Gas)
  - -Expanded hazardous chemicals
  - -Major new pipelines
  - -Major Port impacts
  - -New Storage tanks holding 3.4 Million Barrels crude
- **Switch to explosive N. Dakota Bakken & high carbon Canadian tar sands crude**
- **Increased crude oil per day processed by refinery**



2

G1-81.123

G1-81.124

G1-81.125

Tesoro misleadingly describes this as a "clean air" project,
but even the DEIR says VOCs & hazards increase…

- **DEIR says hazardous release risk significantly increases**
- **DEIR calls Project neutral for greenhouse gases, Nitrogen Oxides, Sulfur Oxides, and Particulate Matter,** (only Carbon Monoxide decreases), and says the Project will increase VOCs (Volatile Organic Compounds)
- **DEIR leaves out extensive additional impacts** that will further increase air pollution, **needs to be sent back to the Draft Stage**

G1-81.126

G1-81.127

3

In addition to expanding 22 big Heaters the Carson cracking unit, & more the Project adds a dozen new Pressure Relief connections to Flares.

- **The EIR counted zero flare emissions,** despite Tesoro's application showing tons of pollutants per hour can be connected through new relief devices to flares
- **Flaring is already large,** new project adds to burden
- **Tesoro stated it only included "normal" operations** (when flares are not in use)
- **According to expert testimony, DEIR underestimates emissions** of heater, storage tank, marine vessel, & other sources, cannot be finalized as is

Tesoro Flaring

G1-81.128

4

Tesoro also wants to add 3.4 million barrels of new Crude Oil Storage Tanks!

5

G1-81.129

Increased throughput for new tanks is unprecedented – 420,000 bbls/day
(Larger than the two refineries' existing crude processing of 380,000 bbls/day)

Why does Tesoro need this big crude oil throughput increase for the new tanks?
(far more than Tesoro could claim for faster ships offloading). It enables:

- Using more crude at the combined refinery
- Selling dirty crude to other local refineries
- Exporting crude overseas

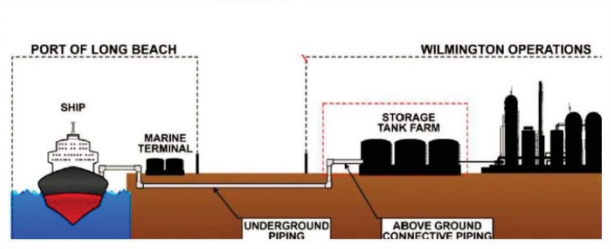
→ DEIR fails to evaluate this

6

G1-81.130

Port impacts were underestimated – Tesoro claims it would benefit air quality to build massive storage, to allow faster ship offloading of crude oil, or larger ships:

- Adding massive crude storage is not the way to clean up the ports.
- **Ship electrification is the way to clean up Port pollution**
- California is already in the process of requiring electrification, but this needs to be speeded up.



G1-81.131

- Expert analysis determined new storage tanks would allow for much larger ships, increased loading, and allows for significantly increased emissions

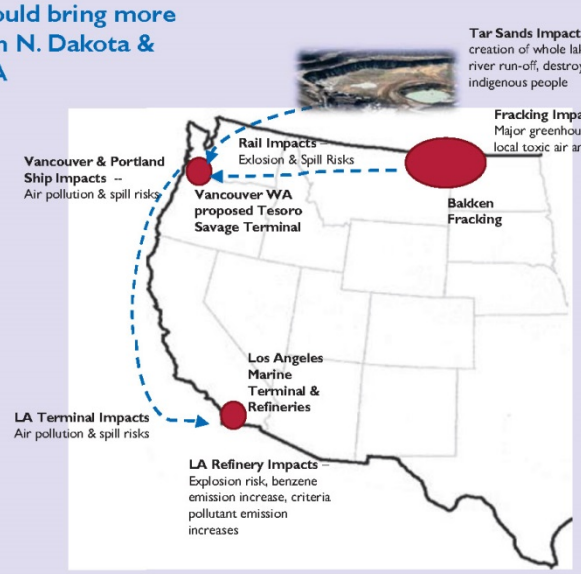
G1-81.132

- DEIR also failed to analyze increased benzene content from Bakken crude oil, and potential impacts at the marine terminal, storage tanks, and the refinery, as well as increased fire and explosion risk from Bakken crude oil.

G1-81.133

7

Upstream, the Project would bring more dangerous crude oils from N. Dakota & Canadian Crude oil, to LA



G1-81.134

8

CHEAP DIRTY CRUDE OIL SWITCH – DEIR doesn't acknowledge it, but Tesoro repeatedly describes to investors the N. Dakota Bakken crude oil switch:

Tesoro's own Slide says →

Supplying Advantaged Crude Oil to the West Coast

Vancouver Energy Project

- Joint venture with Savage Companies
- Up to 360 MBD Rail-to-Marine Terminal
- Most efficient route to West Coast for Bakken crude oil
- Significant infrastructure exists; low development cost

Strategic Crude Supply

- Increases West Coast competitive crude supply
- Relative refining values of $3 to $5 per barrel

Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 09, 2015, p. 10, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations

9

G1-81.135

But Tesoro repeated many times it plans to bring N Dakota crude oil by rail to Vancouver WA, then by ship LA. *For example:*

"When you think about formalizing competitive advantage and fully integrating our value chain, that is really what the Los Angeles Integration and Compliance Project is about.

And when we think about creating value, we are not just thinking about advantaged crude oils in front of our refineries, ***but we're thinking about how that supply to the west coast of advantaged crude oils can change the shape of the crude oil supply/demand dynamics for the west coast. And that's what we are trying to accomplish through Vancouver Energy."***

But Tesoro won't admit this in the Environmental Impact Report!

Thomson Reuters Street Events, Dec. 2015, http://webcache.googleusercontent.com/search?q=cache:9bPuHQPWsH4J:phx.corporate-ir.net/External.File%3Fitem%3DUGFyZW50SUQ9NjA1MTY0fENoaWxkSUQ9MzE2NDI2fFR5cGU9MQ%3D%3D%26t%3D1+&cd=1&hl=en&ct=clnk&gl=us

10

G1-81.136

Devastating Crude Oil Extraction & Greenhouse Emission Impacts in N. Dakota & Canada

Canadian tar sands strip mining pristine land to get at solid tar sands bitumen, also requires very large water volumes, and produces whole toxic lakes, river & fish contamination

N. Dakota Fracking Boom – Major Methane Emissions, Water Pollution, Air Toxics

11

G1-81.137

Tesoro rail-to-ship terminal along Columbia River would bring Bakken & Canadian tar sands crude to LA

After explosions, US DOT found N. Dakota Bakken crude more dangerous

"The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert . . .

. . . the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil."

". . . whether the shipment is in a cargo tank, rail tank car or other mode of transportation.

. . . the materials pose significant fire risk if released from the package in an accident."

→Governors and Mayors in Pacific Northwest have called for a moratorium on crude by rail, and also asked for more environmental review

June 3, 2016 – Latest Bakken crude by rail explosion on Columbia River next to elementary school along route that Tesoro would send its crude oil for this Project

12

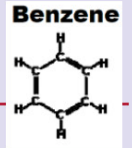
G1-81.138

A Bakken crude by rail accident also killed 47 people after a crude train exploded

13

G1-81.139

N. Dakota crudes contain more Benzene (causes leukemia)
Crude switch increases other hazards in the refinery, Ports, by transport, in oil fields



- **Air District EIR did not include the known higher Benzene content in N. Dakota crude oil,** & increased benzene emissions in new Storage Tanks, ships, transport, and refinery
- **Air District EIR also failed to evaluate the switch to dirtier crude oils**, and the many impacts inside and outside the refinery and Port, including impacts of N. Dakota & Canadian Tar Sands crude imports.
- **These causes many refining impacts,** including increased sulfur decontamination, and increased cracking and coking due to heavy tar sands, and added toxic and explosive diluents, to allow the solid crude oil to flow.
- Bakken crudes were also found in Hydrocarbon Processing Journal as having high wax content, causing refinery fouling, corrosion, and unintended coking.

14

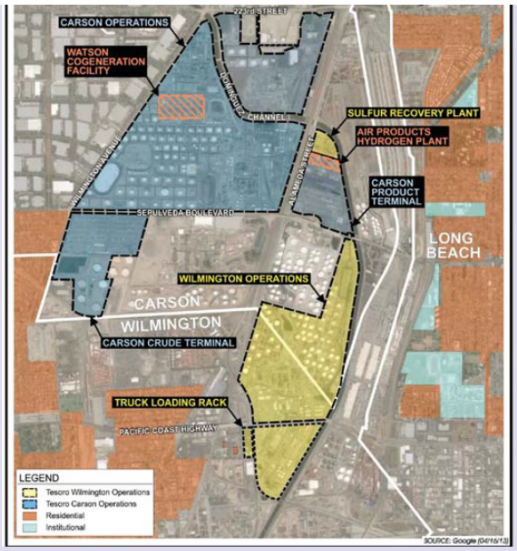
G1-81.140

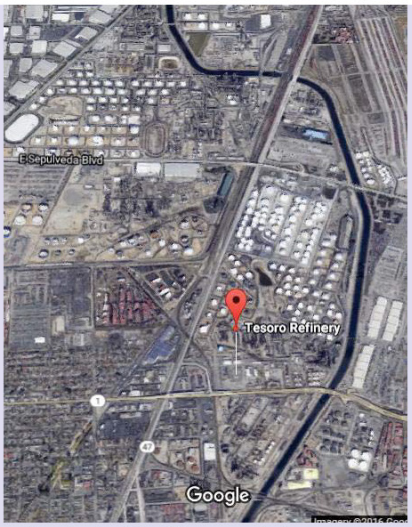
G1-81.141

G1-81.142

G1-81.143

What is the existing context of all these Tesoro expansions in LA?

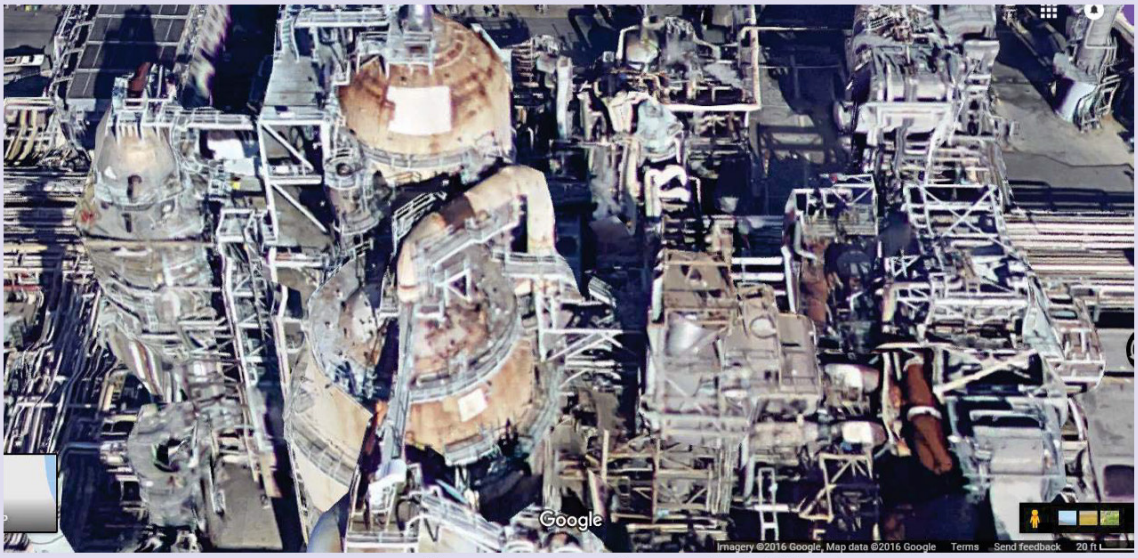




Quick Refinery Tour

15

G1-81.144



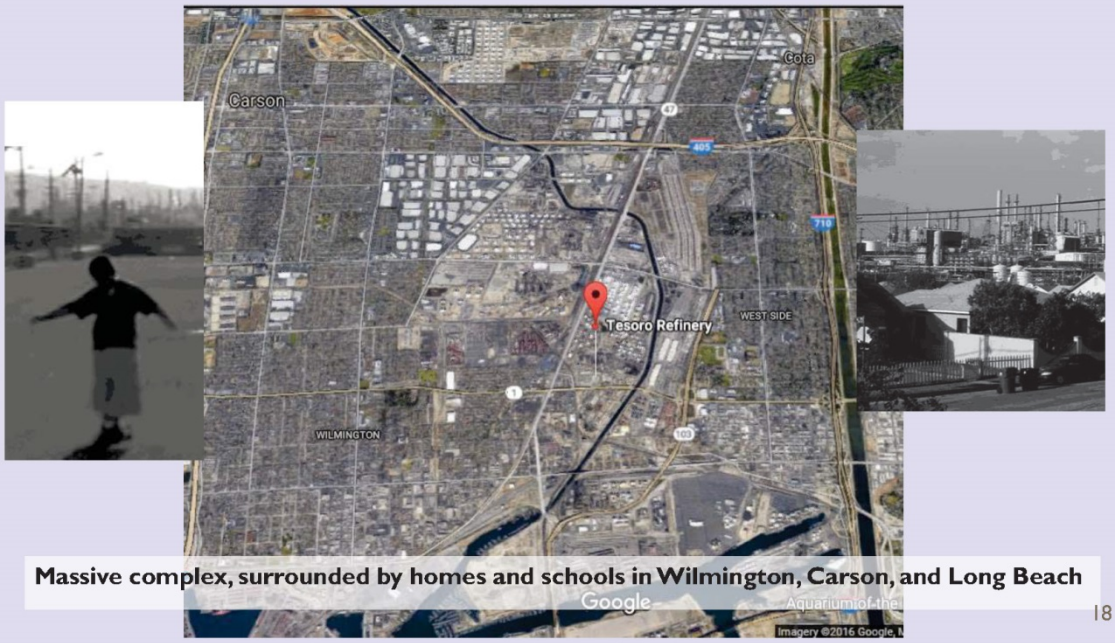
Carson side of the refinery – with big FCC unit

16

Most recently - Sulfur tank blew up. (August 2016), but AQMD could not explain how this could happen. Shelter in place was ordered. Now Tesoro wants to expand hazardous sulfur processing.

17

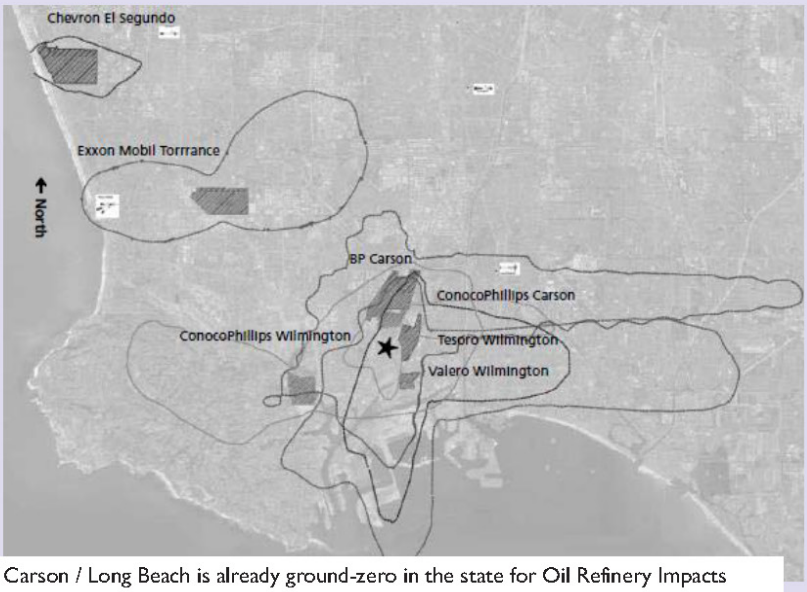
G1-81.145



Massive complex, surrounded by homes and schools in Wilmington, Carson, and Long Beach

18

G1-81.146



Wilmington / Carson / Long Beach is already ground-zero in the state for Oil Refinery Impacts
-- AQMD Plume map of oil refinery air emissions

19

G1-81.147

Who gets the worst Cumulative Impacts of these heavy Fossil Fuel burdens?

- **Over 90% of the population of Wilmington, Carson, and West Long Beach near the refineries are People of Color** (Latino, Asian, Black, Pacific Islander, Native America)
- **This area has 5 oil refineries,** the Ports of LA & Long Beach, the 710 & 110 freeways, heavy diesel truck traffic, and many other pollution sources
- **This extreme concentration of polluting sources in Communities of Color constitutes Environmental Racism**

20

G1-81.148

G1-81.149

G1-81.150

G1-81.151

G1-81.152

G1-81.153

G1-81.154

Excerpt from SCAQMD website, downloaded 12/9/2016, full document available at:

http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgboardsynopsis.pdf?sfvrsn=2

Page 1:

BOARD MEETING DATE: December 5, 2008 AGENDA NO. 31

PROPOSAL: Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans

SYNOPSIS: This action is to adopt a resolution approving the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules, and Plans where AQMD is the lead agency. This interim threshold will be used for determining significant impacts for proposed projects. Once CARB adopts the statewide significance thresholds, staff will report back to the Board regarding any recommended changes or additions to the AQMD's interim threshold.

COMMITTEE: Climate Change, September 19, 2008 and October 29 2008

RECOMMENDED ACTION:
Adopt the attached resolution approving the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules, and Plans for use by the AQMD.

Barry R. Wallerstein, D.Env.
Executive Officer

EC:LT:SN:SS

G1-81.155

Page 5 excerpt:

Emission Calculations and Significance Threshold Proposal – For the purposes of determining whether or not GHG emissions from affected projects are significant, project emissions will include direct, indirect, and, to the extent information is available, life cycle emissions during construction and operation.

The President and CEO of Tesoro, Greg Goff, stated the following in the first quarter 2014 earnings call in response to questions:[1]

"Paul Y. Cheng - Barclays Capital - Analyst

Okay. In Carson [Los Angeles], I think before being acquired by you guys, that they were running largely you said[2] ANS, maybe 100,000 barrel per day. And then maybe another 100,000 of the Iraqi Basra[3]. Is the crude slate changed now? Or that is essentially secured by the same crude slate as in the past?

Gregory J. Goff – Tesoro Corporation – President & CEO

Basically the same. We are running some different crudes there, but not material differences at this point in time. It is in our plans to do that. Basically what you described, is the bulk of the crude supply the two sources what is happens in the Los Angeles refinery today.

Paul Y. Cheng - Barclays Capital - Analyst

Right. Greg, how quickly that you think you may start to be able to change the crude slate to do that?[4]

Gregory J. Goff – Tesoro Corporation – President & CEO

The first thing, our intention at the Port of Vancouver to be able to do that. (emphasis added)

G1-81.156

Paul Y. Cheng - Barclays Capital - Analyst

You have to wait until the Savage terminal's[5] up and running before you can actually do that?

Gregory J. Goff – Tesoro Corporation – President & CEO

That would allow us to move the most significant volume right now if we do that. We are looking at other things on an ongoing basis to be able to move crudes there. But we have a number of things that we're looking at, but **that is the primary way that we want to be able to improve crude supply cost at the Los Angeles facility.** (emphasis added)

Most recently, Tesoro reiterated in 2016 its plans to import crudes from the Vancouver Terminal to the Los Angeles Refinery in response to a question on the connection between the integrated Los Angeles Refinery and the Vancouver Terminal:

Gregory J. Goff – Tesoro Corporation – President & CEO

"We have said that once Vancouver Energy is up and operating, we'll use crude oil into the facility to supply our west coast operations but there's no connection to the permits."[6]

[1] Thomson Reuters Streetevents Edited Transcript, TSO – Q1 2014 Tesoro Corporation Earnings Conference Call, May 1, 2014 (Q1 2014 Tesoro Earnings Call), Barclay Capital questions at pp. 12-13. There are some discrepancies between the Thomson Reuters transcript and the original webcast. The recording of the original webcast is available.

[2] "you said" mistranscribed as "essential"

[3] "Basra" mistranscribed as "basket".

[4] "slate to do that" mistranscribed as "slated to buy it?"

[5] "Savage terminal" mistranscribed as "terminal".

[6] Tesoro, 2016 Tesoro Corporation Earnings Conference Call Recording, May 5, 2016, 41:39 – 41:50 minutes, Exhibit 5a; Available at: http://edge.media-server.com/m/p/56vao56c; Thomson Reuters Streetevents Edited Transcript, TSO – Q1 2016 Tesoro Corporation Earnings Conference Call, May 5, 2016, p. 14.

Response G1-81.123

As explained in Master Response 7, Tesoro acquired the Carson Operations from BP in 2013. The Carson and Wilmington Operations have already merged, and the two pre-existing refinery operations have been operating as one Refinery since the acquisition. As described in Section 2.1 of the DEIR, the proposed project is designed to better integrate the Carson and Wilmington Operations.

The slide presents a list of items under the header “Extensive Additions”. However, the list mischaracterizes the following components of the propose project.

The comment incorrectly refers to "expansion" of the Carson Operations FCCU. No physical modifications are proposed at the Carson Operations FCCU; as noted in the DEIR, the throughput capability of the Carson Operations FCCU will remain unchanged (see Section 2.7.2.2). However, as noted in Section 4.1.2.3 of the DEIR, the Carson Operations FCCU is expected to operate more consistently at its demonstrated capacity of 102,500 bbl/day.

The comment refers to new or increased use of 22 Refinery heaters and boilers. The DEIR fully evaluated potential project impacts; including direct and indirect impacts (see Section 4.1.2.1 of the FEIR). Seven heaters would be installed or modified as part of the proposed project resulting in direct project impacts. In addition to these direct impacts associated with the proposed project, "…the proposed project may have indirect impacts on downstream equipment by causing increased utilization from operational changes, even though the equipment is not part of the proposed project, that is, it is not modified in any way, is operating within existing permit limits and no permit modification would be required." The majority of the 22 heaters referenced in the comment are currently permitted to operate at the levels analyzed in the DEIR.

The Refinery currently receives LPG railcar deliveries. The proposed project will not increase the number of LPG trains or trips to the Refinery. The additional ten railcars associated with the proposed project will be added to existing trains.

The proposed project does not introduce any new chemicals, not already in use at the Refinery that would be expected to cause odors or introduce different types of hazards.

The proposed project includes the installation of interconnecting piping to further connect the Carson and Wilmington Operations to operate as a single refinery.

As described in Master Response 4, the proposed project does not enable a change in the types of crude oil processed at the Refinery. The Refinery has historically processed crude oils from around the world, including North American crude oils such as Bakken and Canadian crude oils. As described on pages 4-26 through 4-29 of the DEIR, the size of marine vessels that can be received at the Long Beach Marine Terminal is limited to Panamax and Aframax and the proposed project does not change that limitation. Emission reductions are expected from increasing the offloading rate when transferring crude oil to internal floating roof tanks at the Wilmington Operations. Additionally, the proposed project would reduce anchorage events and

associated emissions between offloading activities at Marine Terminal 1 and does not modify unloading operations.

Response G1-81.124

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and will continue to do so with or without the proposed project. The proposed project is not designed to, and will not in fact, facilitate a change in the slate of crude oils purchased by the Refinery or the crude oil blend processed by the Refinery, except to the extent that the DCU H-100 heater permit revisions may allow the processing of a slightly heavier crude oil blend.

The DEIR has analyzed the potential increase in crude oil processing of up to 6,000 bbl/day associated with the DCU H-100 heater permit revision. The increase in crude oil processing rate is not related to any specific crude oil source. Master Response 4 explains that the Refinery's sources of crude oils have and will continue to vary with or without the proposed project. By using worst-case crude oil properties (see Response G1-78.157), the DEIR fully analyzed the potential impacts associated with storing various crude oils in the new and replacement storage tanks and with transferring various crude oils via the associated piping. There would be no additional impacts, beyond those analyzed in the DEIR, for the new and replacement storage tanks if different light or heavy crude oil is processed at the Refinery (see Section 4.2.2.2 of the FEIR). The proposed project does not facilitate or encourage sourcing crude oil from any particular location. In other words, the improved offloading efficiency benefits all crude oil transported by marine vessel equally.

Light and heavy crude oil is currently delivered, stored, and processed at the Refinery and will continue to be delivered, stored, and processed with or without the proposed project. The impact analysis in the DEIR accounts for the variety of crude oils that have been and will be handled by the Refinery. For example, the TAC concentrations of crude oils in storage tanks associated with the proposed project were based on a worst-case hybrid analysis of the toxic content of the crude oils currently and potentially processed at the Refinery, including Bakken and heavy Canadian crude oil. The hybrid TAC speciation was prepared by selecting the highest concentration of each toxic compound from the entire speciated data set of all the crude oils analyzed.

There have been previous volatility issues associated with the transport of Bakken crude oil. However, regulations have since been adopted that require a reduction in volatility of Bakken crude oil that is transported. For example, in December 2014, the Industrial Commission of North Dakota issued an order regarding conditioning of Bakken crude oil and limiting the RVP of crude oil provided for transport to 13.7 RVP. Thus, Bakken crude oil transported to the West Coast will be pipeline quality (i.e., qualified for safe transport) and will not have as high a vapor pressure as the Bakken crude oil produced at the wellhead. As with other U. S. crude oil production operations, the order adopted by the State of North Dakota will require that crude oil production facilities remove a significant portion of the light ends (ethane, propane, butane and pentane) prior to offering the crude oil for shipment to refineries for processing.

Because of Bakken crude oil's purported volatility, concerns were raised in the media as to whether Bakken crude oil was properly classified as a Class 3 hazardous material under U.S. DOT regulations. A Class 3 hazardous material is generally a flammable or combustible liquid that does not meet the regulatory classification requirements for other hazardous characteristics, such as toxicity, corrosivity, radioactivity or explosiveness. However, those concerns have since been resolved by repeated analysis and testing that demonstrates Bakken crude oil to be a Class 3 hazardous material, similar to other light sweet crude oils. After considering the information, the Pipeline and Hazardous Material Safety Administration (PHMSA) Deputy Administrator testified to Congress that Bakken crude oil is accurately classified as a Hazard Class 3 Flammable Liquid.[290] This is consistent with the sampling and testing Tesoro has completed on Bakken crude oil. Therefore, Bakken crude oil has properties similar to other light crude oils, and is not classified as explosive.

As explained in subsequent responses, which are listed in Table 78-94.1, Bakken and heavy Canadian crude oils are similar to other light and heavy crude oils currently processed by the Refinery. As described in Master Response 4, and Response G1-78.150, in the future, as now, any Bakken or heavy Canadian crude oils processed would have to be combined to create a crude oil blend that matches the Refinery's processing capabilities and permit limitations. This is what has occurred with the amounts of Bakken, heavy Canadian, and many other heavy and light crude oils that were utilized in the baseline period, and is what will occur after implementation of the proposed project. It is correct to say that Tesoro makes ongoing efforts to provide "advantaged crude oil", as that term is used by Tesoro (i.e., any economically advantaged crude oil capable of being processed at each of Tesoro's refineries). Providing "advantaged crude oil" to Tesoro refineries, including the Los Angeles Refinery, is occurring independent of the proposed project. Any increased use of Bakken or heavy Canadian crude oils, or any other specific crude oils, would not be caused by the proposed project. The proposed project's impacts were analyzed in detail using worst-case assumptions (e.g., vapor pressure of crude oil approaching the maximum allowable by SCAQMD rules), which accounts for any impacts from increased use of Bakken or heavy Canadian crude oil, if any.

Response G1-81.125

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revisions. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

Response G1-81.126

The slide accurately summarizes the conclusions in the DEIR. However, the VOC increase as a result of the proposed project is only significant during construction, and will be less than significant once the proposed project is operational.

[290] Written statement of Timothy P. Butters Before the Subcommittees on Energy and Oversight Committee on Science, Space and Technology, U.S. House of Representatives at page 12 (Sept. 9, 2014).

Response G1-81.127

This point on the slide presents the summary conclusion of Comment Letter G1-81. See Responses G1-81.1 through G1-81.122 for the comprehensive responses that explain the DEIR fully and adequately analyzed the proposed project.

Response G1-81.128

See Responses G1-81.69 through G1-81.78 that address flaring. See Responses G1-81.79 through G1-81.88 that address the process unit heaters. See Responses G1-81.39 through G1-81.51 that address storage tanks. See Response G1-81.117 that addresses potential marine vessel impacts.

Response G1-81.129

See Response G1-81.39 that describes the existing crude oil storage capacity at the Wilmington and Carson Operations.

Response G1-81.130

See Responses G1-81.39 and G1-81.40 that address the crude oil throughput of the proposed new and replacement storage tanks at the Wilmington and Carson Operations. See Response G1-81.52 that addresses the inability to export crude oil from the Carson Crude Terminal.

Response G1-81.131

As described in Sections 2.7.2.11 and 4.2.2.2.2 of the DEIR, the proposed project will result in a decrease in transportation emissions with respect to marine vessels that deliver crude oil. Because the proposed project does not result in a significant increase of marine vessel emissions or any emissions, installation of additional "cold ironing" capability as mitigation or a project alternative is not necessary. Cold ironing means that a marine vessel can completely shut down its main engine and allow its pumps to be run by shore side electricity.

The proposed project provides several advantages for emission reductions and offloading efficiency. The new and replacement storage tanks enable Tesoro to meet the proposed project objective of increased offloading efficiency which reduces marine vessel demurrage costs. Additionally, the proposed project would reduce maneuvering and hoteling emissions that occur while marine vessels wait for available storage space to offload into on-shore storage tanks that would not be reduced by cold ironing. The additional hoteling associated with marine vessels waiting for on-shore storage space are a substantial portion of offloading emissions (see Master Response 6), and these emissions would not be reduced with cold ironing.

Response G1-81.132

As described in DEIR Section 4.2.2.2.2, the Wilmington Operations Long Beach Marine Terminal currently receives crude oil shipments only in vessels of two size classes, Panamax

(400,000 bbl capacity) and Aframax (720,000 bbl capacity) and will continue to receive crude oil in the same size vessels once the proposed project becomes operational. Marine vessels larger than an Aframax cannot be handled at the Long Beach Marine Terminal because of its location within the Port of Long Beach and the water depth at the Marine Terminal location, and, as described below, Marine Terminal 1 already receives Very Large Crude Carriers (VLCC) with up to two million bbl capacity.

As described in the DEIR (see pages 4-26 through 4-29), the proposed project will increase the crude oil storage capacity at the Refinery and increase the offloading rate from 5,000 bbl/day to 15,000 bbl/day when unloading into floating roof storage tanks at the Wilmington Operations, which will reduce the amount of time that marine vessels spend at the Port.

Marine Terminal 1 already receives the largest marine vessels which it is capable of unloading (i.e., Very Large Crude Carrier (VLCC) up to two million bbl capacity). As explained discussed in Section 2.7.2.11, currently marine vessels often unload a portion of the crude oil at Marine Terminal 1, then leave the Terminal and anchor within the Port until sufficient room has been made within the existing crude oil storage tanks to unload the remaining portion of the crude oil. As explained in Master Response 6, in 2015, 41 anchorage events occurred (i.e., a marine vessel delivering crude oil which could not unload all its contents at one time) for an average duration of over seven days each. These anchorage events resulted in approximate excess annual emissions of 36, 25, 200, 3, and 8 tons of VOC, CO, NOx, SOx, and PM, respectively. The additional crude oil storage tanks would allow for demurrage costs and these anchorage emissions to be reduced, if not eliminated entirely. Any single day of ship anchorage that is eliminated by installing the proposed crude oil storage tanks will result in emissions benefits.

Response G1-81.133

See Responses G1-81.41 and G1-81.44 regarding the analysis of TAC, including benzene, emissions from the proposed storage tanks.

Response G1-81.134

See Response G1-81.25 that addresses the fact that the Vancouver Energy Project is unrelated to and independent of the proposed project and Responses G1-81.53 through G1-81.67 that address Bakken and heavy Canadian crude oil processing.

Response G1-81.135

See Response G1-81.22 that explains the slide when presented in proper context.

Response G1-81.136

See Response G1-81.22 that addresses the quotes presented in the slide.

Response G1-81.137

See Responses G1-81.65 through G1-81.67 that address production impacts related to Bakken and heavy Canadian crude oils.

Response G1-81.138

See Responses G1-81.53 through G1-81.58 that address the hazardous characteristics of Bakken crude oil. Response G1-81.57 specifically discusses the U.S. Department of Transportation's Safety Alert.

Response G1-81.139

The slide presents an accident that is unrelated to the proposed project and makes no reference to the DEIR. Therefore, no further response is required under CEQA.

Response G1-81.140

See Responses G1-81.53 through G1-81.58 that address Bakken crude oil properties.

Response G1-81.141

See Response G1-81.53 that explains the proposed project does not facilitate a switch to a new slate of crude oils.

Response G1-81.142

See Responses G1-81.31, G1-81.38, and G1-81.105 that address desulfurization capacity. See Responses G1-78.170 regarding coking impacts. See Responses G1-78.164 through G1-78.168 that address use of diluents.

Response G1-81.143

See Responses G1-81.54 and G1-81.55 that address wax properties of Bakken crude oil. See Response G1-78.111 regarding corrosion impacts. See Responses G1-78.170 regarding coking impacts.

Response G1-81.144

The photos presented in the slides show the existing Tesoro locations and existing equipment which establish the existing setting. Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's Carson and Wilmington Operations.

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revisions. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

Response G1-81.145

The proposed project does not propose to build new sulfur processing units, but includes the SARP, which will allow regeneration of sulfuric acid.

The sulfur tank event that occurred at the Refinery on August 26, 2016, is unrelated to the proposed project. No modifications are included in the proposed project that would impact the SRP in any way. However, the sulfur tank event was thoroughly investigated following Tesoro's Incident Investigation criteria, work process, and methodologies. An incident investigation team with representation by specific disciplines (e.g. technical, operations, and maintenance) as well as an outside industry expert conducted an incident investigation root cause analysis. Root cause methodology reviews incident data for cause, identifies causal factors and root causes, and provides the associated recommendations, which are implemented with the goal of incident prevention and recurrence.

Tesoro reports that the cause of the event is believed to have been solid sulfur blockages in the storage tank vent gas blower suction line. The sulfur blockage led to low flow conditions which caused combustible vapors to build up in the tank vapor space in excess of the flammability concentration. An unknown ignition source then ignited the vapors that started the fire. Corrective actions included calculating a safe minimum operating vent gas rate and changing the vent gas flow alarms on the sulfur tank based on the calculated safe minimum operating vent gas rate. Ongoing corrective action also includes a re-evaluation of the design of the existing sulfur tank venting system to determine if there are any better long-term engineered solutions that can be feasibly implemented.

Response G1-81.146

As depicted in the slide and described in Section 2.4.2 of the DEIR, the Refinery is in a mixed industrial and urban area.

Response G1-81.147

See Response G1-81.98 that addresses this slide.

Response G1-81.148

See Master Response 14 that addresses environmental justice issues. See Master Response 16 that addresses cumulative impacts.

Response G1-81.149

The comment is a conclusory statement of the presentation. See Responses G1-81.123 through G1-81.148 that refute the claims made. The proposed project is designed to meet the objectives expressively stated in Section 2.2 of the DEIR. As explained in the Responses G1-81.1 through G1-81.148, the DEIR fully described and analyzed the proposed project and the associated environmental impacts.

Response G1-81.150

As explained in Section 4.1.2.5 of the DEIR and Master Response 8, the Vancouver Energy Project is wholly independent from the proposed project and is undergoing separate environmental review by the Washington State EFSEC, which includes the evaluation of transportation hazards. Additionally, as described in Master Response 8, the Final EIS has not yet been issued for the Vancouver Energy Project, and the project has not been approved. See also Responses G1-81.22 and G1-81.59 regarding the Vancouver Energy Project.

Response G1-81.151

Chapters 4, 5, and 6 of the DEIR fully analyzed the proposed project's potential impacts and the comment does not provide any new information of environmental impacts that was not analyzed or that changes the significance conclusions made in the DEIR. Therefore, no substantial revision and/or recirculation of the DEIR is necessary under CEQA.

Master Response 5 explains that the current Refinery capacity is 380,000 bbl/day. The proposed project does not enable the Refinery to achieve this capacity. The reported capacity of 380,000 bbl/day has already been achieved by the various individual crude processing units in the Refinery. The current Refinery capacity of 380,000 bbl/day is noted in the FEIR.

Responses G1-81.1 though G1-81.122 address comments raised on the DEIR.

Response G1-81.152

See Response G1-81.96 that addresses the activities mentioned in the slide and the independence of those items, which are baseline conditions, from the proposed project.

Response G1-81.153

Chapter 6 of the DEIR discusses alternatives to the proposed project in detail, a summary of which can be found on page 6-54. The DEIR found that while several of the alternatives discussed meet many of the project objectives, none of the project alternatives would eliminate the potentially significant adverse construction air quality and hazard impacts except Alternative 1, the No Project Alternative. As a result, when balancing environmental impacts with achieving project objectives, the proposed project was the preferred choice as it would most effectively meet all project objectives.

Response G1-81.154

The DEIR fully analyzed the proposed project's potential impacts and the comments do not provide any new information of environmental impacts that was not analyzed or that changes the significance conclusions made in the DEIR. Therefore, no recirculation of the DEIR is necessary under CEQA.

The proposed project has complied with the public process required by CEQA Guidelines § 15087. As explained in detail in Master Response 1, the DEIR was circulated for an extended length of time. The public comment period closed on June 10, 2016, after two extensions. A 94-day public review and comment period (March 8, 2016 through June 10, 2016) was provided, which exceeds CEQA requirements. A public hearing on the Title V permit and public meeting on the DEIR was held on May 17, 2016. Copies of the DEIR were made available in neighborhood public libraries. Notices were published and distributed for the original public comment period, the two extensions, and the public hearing on the Title V permit and public meeting on the DEIR. Therefore, no additional public meeting is required.

Response G1-81.155

On December 5, 2008, the SCAQMD Governing Board adopted the staff proposal for an interim GHG significance threshold for projects where the SCAQMD is lead agency. While the lifecycle emissions are to be considered "to the extent information is available,"[291] predicting the GHG emissions from the sources of crude oil purchased by Tesoro is not reasonably achievable because the source of crude oil varies widely as shown in Master Response 4 Table G0-2.4-1. Moreover, the decisions with respect to sourcing the crude oil slate are made independent of the proposed project. As such, the life-cycle emissions of the Refinery's crude oil slate (including the potential for increases in GHG emissions at the source of any crude oil) are not influenced by the proposed project and are not a reasonably foreseeable impact caused directly or indirectly as a result of the proposed project. Additionally, the specifics of the operations at each oil production field vary by operator and are not affected by the proposed project. This information is not publicly available. Further, in December 2009, the California Natural Resources Agency removed the term "lifecycle" from the CEQA Guidelines Appendix F guidance on analysis and mitigation of energy impacts from proposed projects in conjunction with its rulemaking pertaining to analysis and mitigation of GHG impacts.[292] Therefore, lifecycle impacts need not be analyzed.

[291] SCAQMD Board Letter, Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans, December 8, 2008, http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgboardsynopsis.pdf?sfvrsn=2.

[292] California Natural Resources Agency, 2009. Final Statement of Reasons for Regulatory Action for the Amendments to the State CEQA Guidelines Addressing Analysis and Mitigation of Greenhouse Gases Emissions Pursuant to SB97, December 2009, http://resources.ca.gov/ceqa/docs/Final_Statement_of_Reasons.pdf.

Response G1-81.156

See Response 78.133 that addresses the quoted corporate earnings calls and explains the context of the conversations.

Comment Letter No. G1-82

Re: Comments Opposing Approval of both the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro Los Angeles Refinery Integration and Compliance Project (LARIC)

Dear Ms. Wong and Mr. Luong,

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project, including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more.

My name is Jan Victor Andasan. I have lived in Carson for seventeen years. Before I lived in Carson, I lived right next to what is now known as Tesoro Carson Facility (back then it was British Petroleum) in West Long Beach. For nineteen years of my life, I have either lived next to or adjacent to a refinery that pollutes a predominantly people of color working class community.

I understand the consequences of what it means to live next to a refinery that pollutes the air and impacts the health of residents living along these facilities. I am also a Community Organizer in West Long Beach for East Yard Communities for Environmental Justice. I work with many residents that live next to the Tesoro Refinery. G1-82.1

Unfortunately, in both West Long Beach and Carson, the Tesoro refinery is not the only source of pollution. Community members bear the burden of having to breathe polluted air from **a multitude of polluting facilities**. In the region, Tesoro is one of three refineries that exist between the cities. The Port of Long Beach and Port of Los Angeles operate adjacent to these communities that will soon be hosting mega ships coming from Asia. Combined, the Port of Long Beach and Los Angeles is the largest port in the nation. Along with the port, there are multitudes of trucks that pass through residential areas, schools, parks, and so on. Finally, there is also an incinerator located in Long Beach that burns trash and emits various pollutants in the region.

Why does any of this matter? Tesoro's DEIR fails to note the **cumulative impacts** of the many polluting facilities in the region. Absent from the entire DEIR is the true context for this project. This project is taking place in one of the most disproportionately impacted communities in all of California. Both locations of the Tesoro refinery are located either in an area designated by California as the top 25% of most disadvantaged communities or surrounded on all sides by areas designated in the top 25% of most disadvantaged communities. This project will add to the already disproportionate amount of air pollution residents experience on a daily basis. G1-82.2

On the subject of cumulative impacts, the DEIR uses claimed reductions from the Port of Los Angeles Southern California International Gateway (SCIG) project to show the air cumulatively getting cleaner in the project area. They use this to show that emissions in the project are going G1-82.3

down for the criteria pollutants. As a community organizer for East Yard Communities for Environmental Justice and working with many residents who oppose SCIG, this is highly offensive. It is absurd that the DEIR is using assumptions from the SCIG projects as part of their report on "Cumulative Operational Emissions." The SCIG project will bring more pollution into the community and therefore the DEIR cannot use this proposed project as part of their data set. This is unacceptable. It is clear that this DEIR is not presenting factual data to articulate how various pollutants and emissions will impact the community and to what extent.

G1-82.3 cont'd.

Our community already suffers from too much air pollution and dangers of petroleum storage, pipelines, and refining. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process.

G1-82.4

I appreciate your consideration of these comments. Please do not hesitate to contact if you have questions about these comments.

Sincerely,
Jan Victor F. Andasan
549 W. 224th Pl.
Carson, CA 90745

Response to Comment Letter No. G1-82

Jan Victor Andasan

Comment G1-82.1

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project, including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more.

My name is Jan Victor Andasan. I have lived in Carson for seventeen years. Before I lived in Carson, I lived right next to what is now known as Tesoro Carson Facility (back then it was British Petroleum) in West Long Beach. For nineteen years of my life, I have either lived next to or adjacent to a refinery that pollutes a predominantly people of color working class community.

I understand the consequences of what it means to live next to a refinery that pollutes the air and impacts the health of residents living along these facilities. I am also a Community Organizer in West Long Beach for East Yard Communities for Environmental Justice. I work with many residents that live next to the Tesoro Refinery.

Unfortunately, in both West Long Beach and Carson, the Tesoro refinery is not the only source of pollution. Community members bear the burden of having to breathe polluted air from **a multitude of polluting facilities**. In the region, Tesoro is one of three refineries that exist between the cities. The Port of Long Beach and Port of Los Angeles operate adjacent to these communities that will soon be hosting mega ships coming from Asia. Combined, the Port of Long Beach and Los Angeles is the largest port in the nation. Along with the port, there are multitudes of trucks that pass through residential areas, schools, parks, and so on. Finally, there is also an incinerator located in Long Beach that burns trash and emits various pollutants in the region.

G1-82.1

Response G1-82.1

The comment regarding opposition to the proposed project does not raise issues related to the proposed project or the DEIR. The comment is noted and no response is necessary under CEQA.

Although the proposed project includes adding new storage tanks, this component of the proposed project would not increase the crude oil throughput capacity at the Refinery. Instead, the new crude oil storage tanks would allow the Refinery to reduce transportation emissions associated with marine vessels that deliver crude oil. As explained in the DEIR (see pages 4-26 through 4-29) and Master Response 6, the proposed project will increase the crude oil storage capacity at the Refinery, which will reduce the amount of time that marine vessels spend at the Port and the associated emissions.

Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity; it would further integrate the Refinery's Carson and Wilmington Operations. Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be

accommodated with the DCU H-100 heater permit revision. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

Master Response 15 and Response G1-78.207 address the new connections of pressure relief valves to the flare gas recovery system, which do not increase flaring.

The comment refers to increased use of 22 Refinery heaters and boilers. Response G1-81.79 addresses heaters and boilers. The DEIR fully analyzed proposed project impacts, including increased use of and modifications to numerous process heaters. As indicated in Section 4.1.2 of the FEIR, in addition to direct impacts, the proposed project may have indirect impacts on downstream equipment, including Refinery heaters, by causing increased utilization from operational changes, even though the equipment is not part of the proposed project. That is downstream equipment that will not be modified in any way, will operate within existing permit limits and no permit modification would be required. The anticipated indirect operational changes are described in Section 4.1.2 and are included as part of the analysis of operational impacts in Section 4.2.2.2 of the FEIR. Even though there is potential for increased operation of the various Refinery heaters, overall the proposed project will result in localized emission reduction benefits.

The Refinery currently receives LPG railcar deliveries. The proposed project will not increase the number of deliveries. The additional ten railcars associated with the proposed project will be added to existing trains. The potential risks associated with rail transport were analyzed in Section 4.3.2.5.2 of the FEIR. The Worst-Case Consequence Analysis for the proposed project carefully evaluated the proposed modifications to existing equipment and proposed new units (see Appendix C of the FEIR).

The comments describing the existing setting do not specify any issues related to the proposed project or the DEIR. Therefore, no further response is necessary under CEQA.

Comment G1-82.2

Why does any of this matter? Tesoro's DEIR fails to note the **cumulative impacts** of the many polluting facilities in the region. Absent from the entire DEIR is the true context for this project. This project is taking place in one of the most disproportionately impacted communities in all of California. Both locations of the Tesoro refinery are located either in an area designated by California as the top 25% of most disadvantaged communities or surrounded on all sides by areas designated in the top 25% of most disadvantaged communities. This project will add to the already disproportionate amount of air pollution residents experience on a daily basis.

G1-82.2

Response G1-82.2

As analyzed in Chapter 5 of the DEIR and explained in Master Response 16, consistent with SCAQMD's policy and applicable case law, the operational emissions of the proposed project are below SCAQMD's CEQA significance thresholds for all pollutants and thus, are not considered cumulatively considerable.

Neither the CEQA Statutes nor Guidelines require an analysis of environmental justice impacts. The SCAQMD, however, has a strong record of addressing environmental justice issues since the SCAQMD's Environmental Justice program began in 1997. Since that time, the SCAQMD has instituted a number of community initiatives to help improve air quality for low income residents and residents of color in the Basin. The programs and initiatives have been continually reviewed and updated. As a result, the SCAQMD's Environmental Justice program goes beyond a single project, and encompasses a unified regional approach to reducing impacts to the Basin's most impacted communities. Master Response 14 addresses environmental justice regarding the proposed project.

Comment G1-82.3

On the subject of cumulative impacts, the DEIR uses claimed reductions from the Port of Los Angeles Southern California International Gateway (SCIG) project to show the air cumulatively getting cleaner in the project area. They use this to show that emissions in the project are going down for the criteria pollutants. As a community organizer for East Yard Communities for Environmental Justice and working with many residents who oppose SCIG, this is highly offensive. It is absurd that the DEIR is using assumptions from the SCIG projects as part of their report on "Cumulative Operational Emissions." The SCIG project will bring more pollution into the community and therefore the DEIR cannot use this proposed project as part of their data set. This is unacceptable. It is clear that this DEIR is not presenting factual data to articulate how various pollutants and emissions will impact the community and to what extent.

G1-82.3

G1-82.3 cont'd.

Response G1-82.3

The certification of the EIR for the Southern California International Gateway (SCIG) project was recently set aside by a superior court, and accordingly, the emission reductions associated with the SCIG project should not be considered in the environmental analysis of the proposed project. However, the invalidation of the SCIG EIR does not alter the analysis or conclusions in the DEIR because the SCIG emission reductions were not considered in the determination of cumulative impacts. Moreover, the DEIR disclosed the fact that the SCIG emission reductions disclosed in the DEIR were tentative and annotated the references to SCIG with a disclaimer that the SCIG environmental analysis "has been challenged and is being litigated" or is "subject to revision pending outcome of ongoing litigation" (see pages 5-17, 5-18, 5-20, and 5-23 of the DEIR). In the FEIR, references to SCIG emission calculations in Chapter 5 have been removed.

The conclusion in the DEIR that the operational emission impacts of the proposed project are not cumulatively significant did not rely upon the emission reductions reported in the SCIG EIR. The emissions from the cumulative projects were listed in Tables 5.2-1 and 5.2.-2 of the DEIR for informational purposes. But, the emissions are not summed in order to determine cumulative impacts. As explained in Master Response 16, consistent with SCAQMD's policy, the operational emissions of the proposed project are below significance thresholds for all pollutants and thus, are not considered cumulatively considerable. Accordingly, the removal of the SCIG project does not affect the cumulative impacts emissions findings of the DEIR for the proposed project.

Comment G1-82.4

Our community already suffers from too much air pollution and dangers of petroleum storage, pipelines, and refining. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process. G1-82.4

Response G1-82.4

As explained in Section 4.2.2.2 of the FEIR, upon completion, the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. The proposed project emissions are described in detail in Section 4.2 of the FEIR and are summarized in Table 4.2-4 (see pages 4-16 through 4-18). The proposed project will result in local overall reductions in GHG emissions, as described in Section 5.2 of the FEIR and summarized in Table 5.2-8 (see page 5-26).

Section 3.3.6 of the DEIR describes existing Refinery safety systems at the Tesoro Refinery. As explained in Section 4.3 and Appendix C of the FEIR and Master Response 9, the proposed project has been fully analyzed for hazard impacts based on a worst-case consequence analysis. This includes proposed project equipment, including pipelines and storage tanks, and process units regardless of the cause of release (e.g., human error, equipment failure, sabotage, terrorism, natural disaster, or civil uprising). The DEIR found that hazards associated with the Naphtha Isomerization Unit, new crude oil storage tanks, the SARP, and interconnecting pipelines are potentially significant based on worst-case release scenarios.

Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's Carson and Wilmington Operations.

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the 6,000 bbl/day potential crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revision. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

The proposed project has complied with the public process required by CEQA Guidelines § 15087. As explained in detail in Master Response 1, the DEIR was circulated for an extended length of time. The public comment period closed on June 10, 2016, after two extensions. A 94-day public review and comment period (March 8, 2016 through June 10, 2016) was provided, which exceeds CEQA requirements. A public hearing on the Title V permit and public meeting on the DEIR was held on May 17, 2016. Copies of the DEIR were made available in neighborhood public libraries. Notices were published and distributed for the original public comment period, the two extensions, and the public hearing on the Title V permit and public meeting on the DEIR.

In addition, Tesoro independently offered and provided community outreach to over 100 entities including public agencies, community organizations, neighborhood organizations, business associations, and other interested parties to describe the scope of the proposed project and environmental effects of the proposed project. The community meetings were held on April 4, 11, and 14, 2016 in Carson, Wilmington, and Long Beach, respectively. Tesoro has identified that a total of 277 people attended the meetings.

Comment Letter No. G1-83

From: Kent Minault [mailto:kminault@gmail.com] **On Behalf Of** Kent Minault
Sent: Friday, June 10, 2016 5:00 PM
To: Jillian Wong <jwong1@aqmd.gov>
Cc: Danny Luong <dluong@aqmd.gov>; Organizer Joe <organizer@southbay350.org>
Subject: Proposed Tesoro Merger, Facility ID#s 174655 and 800436

Dear Dr. Wong:

I oppose the Proposed Title V Significant Permit Revisions and the Draft Environmental Impact Report (DEIR) for Tesoro Refining & Marketing Co., LLC's Carson and Wilmington Sites, Facility ID#s 174655 and 800436, and you should, too. G1-83.1

This is an enormous expansion of refinery capacity, and Tesoro is falsely promoting it as a pollution reduction project. But it will increase VOC emissions in our communities which already suffer from some of the worst air quality in the country, which cause high rates of asthma and other diseases. Maybe the emissions of Nox, Sox, PMs and toxins will remain the same, but this will not benefit the public, even if true. G1-83.2

The project will increase refining capacity and add over 3 million barrels of new storage, which is the equivalent of a new oil terminal. My chief worry is that his expansion will prompt Tesoro to start refining dirty and dangerous crude like Canadian Tar Sands and Bakken Shale and bringing it into the Los Angeles Harbor area. The DEIR does not address the overall environmental impacts of such crude. But these highly explosive materials will put the community and Los Angeles/Long Beach Harbors at risk. Additional LPG rail car deliveries, carrying butane and propane will also create increased risks of toxic release hazards at a number of areas of the mega-refinery. G1-83.3

Finally, the project would create an anti-competitive advantage for Tesoro by giving it an even larger share of the California oil market, which could increase prices for consumers.
In sum, the Title V application should be rejected and the DEIR should be sent back for revisions. G1-83.4

Thank you for your consideration:

Response to Comment Letter No. G1-83

Kent Minault

Comment G1-83.1

I oppose the Proposed Title V Significant Permit Revisions and the Draft Environmental Impact Report (DEIR) for Tesoro Refining & Marketing Co., LLC's Carson and Wilmington Sites, Facility ID#s 174655 and 800436, and you should, too. G1-83.1

Response G1-83.1

The comment regarding opposition to the proposed project does not raise issues related to the proposed project or the DEIR. The comment is noted and no response is necessary under CEQA.

Comment G1-83.2

This is an enormous expansion of refinery capacity, and Tesoro is falsely promoting it as a pollution reduction project. But it will increase VOC emissions in our communities which already suffer from some of the worst air quality in the country, which cause high rates of asthma and other diseases. Maybe the emissions of Nox, Sox, PMs and toxins will remain the same, but this will not benefit the public, even if true. G1-83.2

Response G1-83.2

As explained in Master Response 7, the proposed project is not a merger. Tesoro acquired the Carson Operations from BP in 2013. The Carson and Wilmington Operations have already merged. The pre-existing Carson and Wilmington Operations have been operating as one Refinery since the acquisition. As described in Section 2.1 of the DEIR, the proposed project is designed to better integrate the Carson and Wilmington Operations, which will improve processing efficiency and reduce emissions.

The comment claims that the proposed project will not result in an emissions benefit. This statement is incorrect. As explained in Section 4.2.2.2 of the FEIR, upon completion, the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. The proposed project emissions are discussed in detail in Section 4.2 of the FEIR and are summarized in Table 4.2-4 (see pages 4-16 through 4-18). The proposed project will result in local overall reductions in GHG emissions, as discussed in Section 5.2 of the FEIR and summarized in Table 5.2-8 (see page 5-26).

As explained in Master Response 3, the DEIR fully analyzed and disclosed the proposed project's potential health impacts from all pollutants. The proposed project's potential cancer and non-cancer human health impacts, including asthma and other respiratory illnesses, were

analyzed in the DEIR, and determined to be less than significant. The estimated cancer risk due to the operation of the proposed project was found to be less than the SCAQMD's cancer risk significance threshold of ten in one million (see FEIR Section 4.2.2.5). The non-cancer chronic and acute hazard indices were found to be below the SCAQMD's non-cancer chronic and acute hazard index threshold of 1.0. Therefore, the proposed project is not expected to cause a significant adverse health impact.

Comment G1-83.3

The project will increase refining capacity and add over 3 million barrels of new storage, which is the equivalent of a new oil terminal. My chief worry is that his expansion will prompt Tesoro to start refining dirty and dangerous crude like Canadian Tar Sands and Bakken Shale and bringing it into the Los Angeles Harbor area. The DEIR does not address the overall environmental impacts of such crude. But these highly explosive materials will put the community and Los Angeles/Long Beach Harbors at risk. Additional LPG rail car deliveries, carrying butane and propane will also create increased risks of toxic release hazards at a number of areas of the mega-refinery. G1-83.3

Response G1-83.3

Although the proposed project includes adding new storage tanks, this component of the proposed project would not increase the crude oil throughput capacity at the Refinery. Instead, the new crude oil storage tanks would allow the Refinery to reduce transportation emissions associated with marine vessels that deliver crude oil. As explained in the DEIR (see pages 4-26 through 4-29) and Master Response 6, the proposed project will increase the crude oil storage capacity at the Refinery, which will reduce the amount of time that marine vessels spend at the Port and the associated emissions.

Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's Carson and Wilmington Operations.

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revision. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4 and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and will continue to do so with or without the proposed project. The proposed project will not result in a substantial change in the crude oil blend processed by the Refinery.

The DEIR analyzed the potential increase in crude oil processing of up to 6,000 bbl/day associated with the modification of the DCU H-100 heater permit description. The increase in crude oil processing rate is not related to any specific crude oil source. Master Response 4

explains that the sources of crude oils have and will continue to vary with or without the proposed project. By using worst-case crude oil properties (see Response G1-78.157), the DEIR fully analyzed the potential impacts associated with storing various crude oils in the new and replacement storage tanks and with transferring various crude oils via the associated piping. There would be no additional impacts, beyond those analyzed in the DEIR, for the new and replacement storage tanks if different light or heavy crude oil is processed at the Refinery (see Section 4.2.2.2 of the FEIR). The proposed project does not facilitate or encourage sourcing crude oil from any particular location. In other words, the improved offloading efficiency provides a benefit regardless of the type of crude oil transported by marine vessel.

Light and heavy crude oil is currently delivered, stored, and processed at the Refinery and will continue to be delivered, stored, and processed with or without the proposed project. The impact analysis in the DEIR accounts for the variety of crude oils that have been and will be handled by the Refinery. For example, the TAC concentrations of crude oils in storage tanks associated with the proposed project were based on a worst-case hybrid analysis of the toxic content of the crude oils currently and potentially processed at the Refinery, including Bakken and heavy Canadian crude oil. The hybrid TAC speciation was prepared by selecting the highest concentration of each toxic compound from the entire speciated data set of all the crude oils analyzed.

As explained in subsequent responses, which are listed in Table 78-94.1, Bakken and heavy Canadian crude oils are similar to other light and heavy crude oils currently processed by the Refinery. As described in Master Response 4 and Response G1-78.150, in the future, as now, any Bakken or heavy Canadian crude oils processed would have to be combined with other crude oils to create a crude oil blend that matches the Refinery's processing capabilities and permit limitations. This is what has occurred with Bakken, heavy Canadian, and many other heavy and light crude oils that were utilized in the baseline period, and is what will continue after implementation of the proposed project. It is correct to say that Tesoro makes ongoing efforts to provide "advantaged crude oil", as that term is used by Tesoro (i.e., any economically advantaged crude oil capable of being processed at each of Tesoro's refineries). Providing "advantaged crude oil" to Tesoro refineries, including the Los Angeles Refinery, is occurring independent of the proposed project. Any increased use of Bakken or heavy Canadian crude oils, or any other specific crude oils, would not be caused by the proposed project. The proposed project's impacts were analyzed in detail using worst-case assumptions (e.g., the maximum vapor pressure of crude oil allowable by SCAQMD rules), which accounts for any impacts from increased use of Bakken or heavy Canadian crude oil. Response G1-78.111 specifically addresses crude oil corrosivity. Responses G1-81.65 and G1-81.67 address greenhouse gases and crude oil production. Therefore, the DEIR fully evaluated the potential impacts of the proposed project.

Section 3.3.6 of the DEIR describes existing Refinery safety systems at the Tesoro Refinery. As explained in Section 4.3 and Appendix C of the FEIR and Master Response 9, the proposed project has been fully analyzed for hazard impacts based on a worst-case consequence analysis. This includes proposed project equipment, including pipelines and storage tanks, and process units regardless of the cause of release (e.g., human error, equipment failure, sabotage, terrorism, natural disaster, or civil uprising). The DEIR found that hazards associated with the Naphtha

Isomerization Unit, new crude oil storage tanks, the SARP, and interconnecting pipelines are potentially significant based on worst-case release scenarios.

The hazard analysis takes a worst-case approach by assuming that the entire contents of a tank or other equipment would rapidly be released, and that no safety measures are implemented that could reduce the severity of an accidental release. It is expected that hazard impacts would be less than analyzed because the Refinery has safety measures in place and specified employees are trained regarding safety measures. Further, the DEIR imposes measures to mitigate hazard impacts (see Section 4.3.3 of the DEIR). Finally, as described in Section 3.3.7 of the DEIR, the Refinery is subject to many laws and regulations that address safety and emergency responses in the event of an accident. Nonetheless, the DEIR conservatively concluded that hazard impacts would remain significant.

The Refinery currently receives LPG railcar deliveries, and the proposed project will not increase the number of deliveries. The additional ten railcars will be added to existing trains. The potential risks associated with rail transport are analyzed in Section 4.3.2.5.2 of the FEIR.

Comment G1-83.4

Finally, the project would create an anti-competitive advantage for Tesoro by giving it an even larger share of the California oil market, which could increase prices for consumers. In sum, the Title V application should be rejected and the DEIR should be sent back for revisions.

G1-83.4

Response G1-83.4

The issues raised about Tesoro increasing its share of the California oil market will not be realized as a result of the proposed project because it will not enable Tesoro to process significantly more crude oil (beyond a limited potential increase of 6,000 bbl/day). See Master Response 7 explaining that the proposed project is not an expansion of the Refinery.

To the extent that the comment regarding an anti-competitive advantage targets Tesoro's acquisition of the BP Carson Operations generally, it is neither related to the proposed project nor supported by substantial evidence. In June 2013, Tesoro purchased the adjacent BP Carson Operations. Prior to the acquisition, the proposed transaction underwent a nine-month investigation by the Federal Trade Commission and the California Attorney General's office to address potential antitrust concerns. Both government agencies found that the acquisition of the BP Carson operations did not violate anti-trust laws and would not give Tesoro an unlawful anti-competitive advantage. The proposed project involves further integration of the Refinery's Wilmington and Carson Operations.

As part of this process, Tesoro agreed to maintain average daily historical fuel production levels for the Carson and Wilmington Operations for at least three years after the acquisition of Carson Operations. Further details regarding the acquisition, including statements taken from the Federal Trade Commission and California Attorney General's reports, can be found in the DEIR on page 2-1.

The consumer price of gasoline in California will not increase as a result of the proposed project, which further integrates two existing Carson and Wilmington Operations, enabling emissions reductions while maintaining the integrated Refinery's overall fuel production capability. There are many factors that determine the price of transportation fuels, such as gasoline. These include the cost of crude oil, distribution and marketing costs, refining costs, and federal and state taxes. These marketplace and market conditions, including supply and demand factors, determine the price consumers pay at the pump, not one refinery's operational efficiencies. Further, as explained in Master Response 7, the proposed project is not an expansion of the Refinery and thus will not give Tesoro a larger share of the oil market.

The comment regarding the rejection of the Title V application does not raise issues related to the proposed project or the DEIR. The comment is noted and no further response is necessary under CEQA. The comment asserts that the DEIR should be sent back for revisions. However, no evidence was provided in the comment requiring revision of the DEIR.

Comment Letter No. G1-84

From: julius calacsan [mailto:julius_calacsan@yahoo.com]
Sent: Friday, June 10, 2016 4:58 PM
To: Jillian Wong <jwong1@aqmd.gov>
Subject: Comments Opposing Approval of both the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro Los Angeles Refinery Integration and Compliance Project (LARIC)

June 10, 2016

Dear Ms. Wong and Mr. Luong,

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project, including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more. G1-84.1

The DEIR and the Title V Permit (which sets permit limits) are inaccurate. They ignore Tesoro's own published plans to bring dangerous N. Dakota Bakken crude oil by rail to the Tesoro Savage Vancouver Washington ship terminal, then by ship to the Los Angeles refinery. This crude oil is particularly explosive. A Bakken crude oil rail accident blew up an entire town in 2013, killing many people. Just last Saturday another crude oil train carrying this material exploded, requiring evacuation of an elementary school, and spilling oil into the Columbia River. Bakken crude also contains high levels of volatile and toxic air contaminants and the DEIR should evaluate this threat. Tesoro's Project could also bring extreme Canadian tar sands crude oil to the LA refinery through the same Tesoro Savage ship terminal. These two crude oils cause increased greenhouse gases and harms to air, land, and water during extraction, and add explosion risks in storage and in refineries. G1-84.2

The DEIR and Title V permit also failed to count air emissions from flaring during startup, shutdown, and maintenance, other air emissions increases, and failed to set permit conditions that would prevent these increased emissions. G1-84.3

Our community already suffers from too much air pollution and dangers of petroleum storage, pipelines, and refining. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process. G1-84.4

Sincerely,
Julius Calacsan
East Yards Communities for Environmental Justice (EYCEJ)


Rail Costs to Clear Bakken
TESORO
$6-7/bbl
$5.50-6.50/bbl
Bakken
$9-10/bbl
$9.50-10.50/bbl
$9-10/bbl
Bakken Crude Oil Supply and Logistics
MBD | 2013 | 2014E | 2015E
Crude Oil Production[1] | 865 | 1,000 | 1,200
Pipeline Export Capacity | 635 | 685 | 685
Rail Export Capacity | 865 | 1,015 | 1,015
West Coast Unloading Capacity | 218 | 395 | 910
East Coast Unloading Capacity | 700 | 780 | 780
West and East Coasts clearing destinations for Bakken crude oil
ote: Rail cost estimates include only the railroad tariff.
Average annual crude oil production, export capacity and price discount estimates based on industry consultant and Tesoro market outlook.
15

Response to Comment Letter No. G1-84

East Yards Communities for Environmental Justice (EYCEJ)

Comment G1-84.1

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project, including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more. G1-84.1

Response G1-84.1

The comment regarding opposition of the proposed project does not raise issues related to the proposed project or the DEIR. The comment is noted and no response is necessary under CEQA.

Although the proposed project includes adding new storage tanks, this component of the proposed project would not increase the crude oil throughput capacity at the Refinery. Instead, the new crude oil storage tanks would allow the Refinery to reduce transportation emissions associated with marine vessels that deliver crude oil. As explained in the DEIR (see pages 4-26 through 4-29) and Master Response 6, the proposed project will increase the crude oil storage capacity at the Refinery, which will reduce the amount of time that marine vessels spend at the Port and the associated emissions.

Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's Carson and Wilmington Operations.

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revision. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

Master Response 15 and Response G1-78.207 address the new connections of pressure relief valves to the flare gas recovery system, which do not increase flaring.

The comment refers to increased use of 22 Refinery heaters and boilers. Response G1-81.79 addresses heaters and boilers. The DEIR fully analyzed proposed project impacts, including increased use of and modifications to numerous process heaters. As indicated in Section 4.1.2of the FEIR, in addition to direct impacts, the proposed project may have indirect impacts on downstream equipment, including Refinery heaters, by causing increased utilization from operational changes, even though the equipment is not part of the proposed project. That is downstream equipment that will not be modified in any way, will operate within existing permit limits and no permit modification would be required. The anticipated indirect operational changes are described in Section 4.1.2 and are included as part of the analysis of operational

impacts in Section 4.2.2.2. Even though there is potential for increased operation of the various Refinery heaters, overall the proposed project will result in localized emission reduction benefits.

The Refinery currently receives LPG railcar deliveries. The proposed project will not increase the number of deliveries. The additional ten railcars associated with the proposed project will be added to existing trains. The potential hazards associated with rail transport were analyzed in Section 4.3.2.5.2 of the DEIR. The Worst-Case Consequence Analysis for the proposed project carefully evaluated the proposed modifications to existing equipment and proposed new units (see Appendix C of the FEIR).

Comment G1-84.2

The DEIR and the Title V Permit (which sets permit limits) are inaccurate. They ignore Tesoro's own published plans to bring dangerous N. Dakota Bakken crude oil by rail to the Tesoro Savage Vancouver Washington ship terminal, then by ship to the Los Angeles refinery. This crude oil is particularly explosive. A Bakken crude oil rail accident blew up an entire town in 2013, killing many people. Just last Saturday another crude oil train carrying this material exploded, requiring evacuation of an elementary school, and spilling oil into the Columbia River. Bakken crude also contains high levels of volatile and toxic air contaminants and the DEIR should evaluate this threat. Tesoro's Project could also bring extreme Canadian tar sands crude oil to the LA refinery through the same Tesoro Savage ship terminal. These two crude oils cause increased greenhouse gases and harms to air, land, and water during extraction, and add explosion risks in storage and in refineries.

G1-84.2

Response G1-84.2

As described in Section 4.1.2.5 of the DEIR and Master Response 8, the Vancouver Energy Project is wholly independent from the proposed project and is undergoing separate environmental review by the Washington State EFSEC, which includes evaluation of transportation hazards. Additionally, as explained in Master Response 8, the Final EIS has not yet been issued for the Vancouver Energy Project, and the project has not been approved.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and will continue to do so with or without the proposed project. The proposed project will not result in a substantial change in the crude oil blend processed by the Refinery.

The DEIR analyzed the potential increase in crude oil processing of up to 6,000 bbl/day associated with the modification of the DCU H-100 heater permit description. The increase in crude oil processing rate is not related to any specific crude oil source. Master Response 4 explains that the Refinery's sources of crude oils have and will continue to vary with or without the proposed project. By using worst-case crude oil properties (see Response G1-78.157), the DEIR fully analyzed the potential impacts associated with storing various crude oils in the new and replacement storage tanks and with transferring various crude oils via the associated piping. There would be no additional impacts, beyond those analyzed in the DEIR, for the new and replacement storage tanks if different light or heavy crude oil is processed at the Refinery (see Section 4.2.2.2 of the FEIR). The proposed project does not facilitate or encourage sourcing crude oil from any particular location. In other words, the improved offloading efficiency provides a benefit regardless of the type of crude oil transported by marine vessel.

Light and heavy crude oil is currently delivered, stored, and processed at the Refinery and will continue to be delivered, stored, and processed with or without the proposed project. The impact analysis in the DEIR accounts for the variety of crude oils that have been and will be handled by the Refinery. For example, the TAC concentrations of crude oils in storage tanks associated with the proposed project were based on a worst-case hybrid analysis of the toxic content of the crude oils currently and potentially processed at the Refinery, including Bakken and heavy Canadian crude oil. The hybrid TAC speciation was prepared by selecting the highest concentration of each toxic compound from the entire speciated data set of all the crude oils analyzed.

There have been previous volatility issues associated with the transport of Bakken crude oil. However, regulations have since been adopted that require a reduction in volatility of Bakken crude oil that is transported. For example, on December 9, 2014, the Industrial Commission of North Dakota issued Order 25417 regarding conditioning of Bakken crude oil and limiting the RVP of crude oil provided for transport to 13.7 RVP. Thus, Bakken crude oil transported to the West Coast will be pipeline quality (i.e., qualified for safe transport) and will not have as high a vapor pressure as the Bakken crude oil produced at the wellhead. As with other U. S. crude oil production operations, the order adopted by the State of North Dakota will require that crude oil production facilities remove a significant portion of the light ends (ethane, propane, butane and pentane) prior to offering the crude oil for shipment to refineries for processing.

Because of Bakken crude oil's purported volatility, concerns were raised in the media as to whether Bakken crude oil was properly classified as a Class 3 hazardous material under U.S. DOT regulations. A Class 3 hazardous material is generally a flammable or combustible liquid that does not meet the regulatory classification requirements for other hazardous characteristics, such as toxicity, corrosivity, radioactivity or explosiveness. However, those concerns have since been resolved by repeated analysis and testing that demonstrates Bakken crude oil to be a Class 3 hazardous material, similar to other light sweet crude oils. After considering the information, the PHMSA Deputy Administrator testified to Congress that Bakken crude oil is accurately classified as a Hazard Class 3 Flammable Liquid.[293] This is consistent with the sampling and testing Tesoro has completed on Bakken crude oil. Therefore, Bakken crude oil has properties similar to other light crude oils, and is not classified as explosive.

The Refinery did not process large amounts of Bakken or Canadian heavy crude oil in the baseline period. This observation, however, is not relevant to the analysis in the DEIR. As explained in subsequent responses, which are listed in Table 78-94.1, Bakken and heavy Canadian crude oils are similar to other light and heavy crude oils currently processed by the Refinery. As described in Master Response 4, and Response G1-78.150, in the future, as now, any Bakken or heavy Canadian crude oils processed would have to be combined with other crude oils to create a crude oil blend that matches the Refinery's processing capabilities and permit limitations. This is what has occurred with Bakken, heavy Canadian, and many other heavy and light crude oils that were utilized in the baseline period, and is what will continue after implementation of the proposed project. Any increased use of Bakken or heavy Canadian crude oils at the Refinery would not be caused by the proposed project. The proposed project's

[293] Written statement of Timothy P. Butters Before the Subcommittees on Energy and Oversight Committee on Science, Space and Technology, U.S. House of Representatives at page 12 (Sept. 9, 2014).

impacts were analyzed in detail using worst-case assumptions (e.g., the maximum vapor pressure of crude oil allowable by SCAQMD rules), which accounts for any impacts from increased use of Bakken or heavy Canadian crude oil. Response G1-78.111 specifically addresses crude oil corrosivity. Responses G1-81.65 and G1-81.67 address greenhouse gases and crude oil production.

The comment also refers to derailment of a train carrying Bakken crude oil in Mosier, Oregon and another unidentifiable derailment. As explained in Response G1-81.57, there are no proposed project modifications to bring crude oil by rail to the Refinery. Thus the Mosier derailment and other derailments are not relevant to the DEIR analysis or the proposed project. Responses G1-81.65 and G1-81.67 explain that the DEIR does not need to analyze the environmental impacts from crude oil production because the proposed project will not cause any changes to that industry.

The comment includes a slide of a map that the comment claims is ". . . Tesoro's map laying out its plans to transport Bakken crude oil to L.A." The map is titled "Rail Costs to Clear Bakken," and shows ranges of costs to transport Bakken crude oil to various locations on the West and East Coasts of the U.S. The map includes a clarifying subtitle "West and East Coasts clearing destinations for Bakken crude oil." There is no reference on the slide or map to any definitive plans to transport Bakken crude oil to any destination, or to any destination in particular or increased amounts.

The DEIR does not analyze crude oil production because the proposed project will not cause any changes to that industry. Tesoro does not own the crude oil production facilities for any of the crude oil that will be purchased to supply its Refinery. Therefore, the detailed information necessary to accurately quantify the GHG impacts from crude oil production facilities is not available and would require speculation to quantify the impacts. GHG emissions resulting from oil production are the responsibility of the crude oil producer.

The FEIR fully analyzed the potential impacts of the proposed project with respect to greenhouse gas emissions in Section 5.2.2.3 and hazards in Section 4.3.2.

Comment G1-84.3

> The DEIR and Title V permit also failed to count air emissions from flaring during startup, shutdown, and maintenance, other air emissions increases, and failed to set permit conditions that would prevent these increased emissions.] G1-84.3

Response G1-84.3

Startup and shutdown emissions, as well as emergency flaring, are discussed in detail in Master Response 15.

As explained in Master Response 15, the Refinery strives for startups, shutdowns, and maintenance without flaring. In any event, there are no new process units associated with the

proposed project that would be expected to flare during startup or shutdown. No additional permit conditions are needed to control startup and shutdown emissions.

Emission changes as a result of the proposed project have been fully analyzed and are discussed in Section 4.2 of the FEIR. An emissions summary can be found on pages 4-16 in Table 4.2-4. Further, the Title V permit limits will be equal to or more restrictive than the emissions analyzed in the DEIR.

The comment also refers to "other air emission increases" that were not accounted for in the DEIR and the Title V permit. The comment lacks specificity. Without further detail regarding these other air emissions, a specific response cannot be provided.

Comment G1-84.4

> Our community already suffers from too much air pollution and dangers of petroleum storage, pipelines, and refining. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process.] G1-84.4

Response G1-84.4

The proposed project's local health effects have been analyzed and are discussed in Master Response 3. Potential hazard impacts, including those related to material storage and pipelines, are explained in Master Response 9. The proposed project is not an expansion of the Refinery. See Response G1-27.1 and Master Responses 6 and 7 for a detailed description of the potential 6,000 bbl/day crude oil capacity increase associated with the proposed project.

The proposed project has complied with the public process required by CEQA Guidelines § 15087. As explained in detail in Master Response 1, the DEIR was circulated for an extended length of time. The public comment period closed on June 10, 2016, after two extensions. A 94-day public review and comment period (March 8, 2016 through June 10, 2016) was provided, which exceeds CEQA requirements. A public hearing on the Title V permit and public meeting on the DEIR was held on May 17, 2016. Copies of the DEIR were made available in neighborhood public libraries. Notices were published and distributed for the original public comment period, the two extensions, and the public hearing on the Title V permit and public meeting on the DEIR.

In addition, Tesoro independently offered and provided community outreach to over 100 entities including public agencies, community organizations, neighborhood organizations, business associations, and other interested parties to explain the scope of the proposed project and the potential environmental effects of the proposed project. The community meetings were held on April 4, 11, and 14, 2016 in Carson, Wilmington, and Long Beach, respectively. Tesoro has identified that a total of 277 people attended the meetings.

Comment Letter No. G1-85

To Ms. Jillian Wong
c/o Office of Planning, Rule Development and Area Sources/CEQA)
Mr. Danny Luong
Senior Enforcement Manager
dluong@aqmd.gov
South Coast Air Quality Management District

June 10, 2016

Re: Comments Opposing Approval of both the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro Los Angeles Refinery Integration and Compliance Project (LARIC)

Dear Ms. Wong and Mr. Luong,

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project,[1] including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more. G1-85.1

The DEIR and the Title V Permit (which sets permit limits) are inaccurate. They ignore Tesoro's own published plans to bring dangerous N. Dakota Bakken crude oil by rail to the Tesoro Savage Vancouver Washington ship terminal,[2] then by ship to the Los Angeles refinery.[3] This crude oil is particularly explosive.[4] A Bakken crude oil rail accident blew up an entire town in 2013, killing many people.[5] Just last Saturday another crude oil train carrying this material exploded, requiring evacuation of an elementary school, and spilling oil into the Columbia River.[6] Bakken crude also contains high levels of volatile and toxic air contaminants and the DEIR should evaluate this threat. Tesoro's Project could also bring extreme Canadian tar sands crude oil to the LA refinery through the same Tesoro Savage ship terminal. These two crude oils cause increased greenhouse gases and harms to air, land, and water during extraction, and add explosion risks in storage and in refineries. G1-85.2

The DEIR and Title V permit also failed to count air emissions from flaring during startup, shutdown, and maintenance, other air emissions increases, and failed to set permit conditions that would prevent these G1-85.3

[1] http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---year-2016
[2] Tesoro just received a two-year extension on the lease for this terminal. https://www.vancouverenergyusa.com/
[3] Tesoro's map showing this is attached, from: Simmons Energy Conference, *Transformation through Distinctive Performance,* February 27, 2014, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations
Tesoro made the following and many other statements about bringing Bakken crude to LA: *"When you think about formalizing competitive advantage and fully integrating our value chain, that is really what the Los Angeles Integration and Compliance Project is about. And when we think about creating value, we are not just thinking about advantaged crude oils in front of our refineries, but we're thinking about how that supply to the west coast of advantaged crude oils can change the shape of the crude oil supply/demand dynamics for the west coast. And that's what we are trying to accomplish through Vancouver Energy."* Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 09, 2015, p. 10, Keith Casey, Tesoro Corporation, EVP Operations
[4] U.S. Department of Transportation, 2014, available at:
http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/1_2_14%20Rail_Safety_Alert.pdf
[5] http://www.earthisland.org/journal/index.php/eij/article/warning_highly_flammable/
[6] Oregon Public Broadcasting (OPB), 6/7/2016, New Spilled Crude Oil Discovered At Mosier Train Crash, http://www.opb.org/news/series/oil-trains/oregon-oil-train-mosier-derailment-cleanup-spill/

increased emissions. The SCAQMD's public records show that Tesoro Refinery was issued 66 Notices of Violation from 2000 to 2015. Our communities' health and safety must not be put at higher risk when Tesoro cannot demonstrate a consistent record to operate within the law. G1-85.3 cont'd.

Our community is already overburdened with air pollution and dangers of petroleum storage, pipelines, and refining. University of Southern California studies show that improvements in air quality have improved the respiratory health of children in our region[7]. Improvements in air quality come with advanced technology, clean energy sources and forward-thinking solutions. We must not revert to outdated practices that will pollute our air and harm our children's lungs. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process. G1-85.4

Sincerely,

Gisele L. Fong, Ph.D.
Chair, Building Healthy Communities: Long Beach, Environmental Health Work Group
Executive Director, EndOil/ Communities for Clean Ports

Sylvia Betancourt
Program Manager, Long Beach Alliance for Children with Asthma

Stella Ursua
President, Green Education, Inc.

Attachment:

[7] http://usceh.blogspot.com/p/infographic-southern-california.html

Response to Comment Letter No. G1-85

Building Healthy Communities, EndOil/ Communities for Clean Ports, Long Beach Alliance for Children with Asthma, and Green Education Inc.

Comment G1-85.1

This letter is to oppose the Draft Environmental Impact Report (DEIR) and the Title V Permit for the Tesoro LARIC Project,[1] including construction of massive new storage tanks to hold millions of barrels of crude oil, increase crude oil going through the refinery, add a dozen new pressure relief device connections to flares, increase use of 22 large refinery heaters, import Liquefied Petroleum Gas by rail to the refinery, and more. G1-85.1

[1] http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---vear-2016

Response G1-85.1

The comment regarding opposition of the proposed project does not raise issues related to the proposed project or the DEIR. The comment is noted and no response is necessary under CEQA.

Although the proposed project includes adding new storage tanks, this component of the proposed project would not increase the crude oil throughput capacity at the Refinery. Instead, the new crude oil storage tanks would allow the Refinery to reduce transportation emissions associated with marine vessels that deliver crude oil. As explained in the DEIR (see pages 4-26 through 4-29) and Master Response 6, the proposed project will increase the crude oil storage capacity at the Refinery, which will reduce the amount of time that marine vessels spend at the Port and the associated emissions.

Master Response 6 explains that the volume of available crude oil storage capacity has no bearing on Refinery crude oil processing capacity. The proposed project would not create a new or larger refinery or result in a substantial increase of crude oil throughput capacity. It would further integrate the Refinery's Carson and Wilmington Operations.

Sections 2.7.1.3 and 4.1.2.1 of the FEIR describe the potential 6,000 bbl/day crude oil capacity increase that could be accommodated with the DCU H-100 heater permit revision. The potential impacts of this crude oil capacity increase are fully analyzed in Chapter 4 of the DEIR. Master Response 7 further explains that the proposed project is not an expansion of the Refinery.

Master Response 15 and Response G1-78.207 address the new connections of pressure relief valves to the flare gas recovery system, which do not increase flaring.

The comment refers to increased use of 22 Refinery heaters and boilers. Response G1-81.79 addresses heaters and boilers. The FEIR fully analyzed proposed project impacts, including increased use of and modifications to numerous process heaters. As indicated in Section 4.1.2 of the FEIR, in addition to direct impacts, the proposed project may have indirect impacts on downstream equipment, including Refinery heaters, by causing increased utilization from operational changes, even though the equipment is not part of the proposed project. That is

downstream equipment that will not be modified in any way, will operate within existing permit limits and no permit modification would be required. The anticipated indirect operational changes are described in Section 4.1.2 and are included as part of the analysis of operational impacts in Section 4.2.2.2. Even though there is potential for increased operation of the various Refinery heaters, overall the proposed project will result in localized emission reduction benefits.

The Refinery currently receives LPG railcar deliveries. The proposed project will not increase the number of deliveries. The additional ten railcars associated with the proposed project will be added to existing trains. The potential hazards associated with rail transport were analyzed in Section 4.3.2.5.2 of the FEIR. The Worst-Case Consequence Analysis for the proposed project carefully evaluated the proposed modifications to existing equipment and proposed new units (see Appendix C of the FEIR).

Comment G1-85.2

The DEIR and the Title V Permit (which sets permit limits) are inaccurate. They ignore Tesoro's own published plans to bring dangerous N. Dakota Bakken crude oil by rail to the Tesoro Savage Vancouver Washington ship terminal,[2] then by ship to the Los Angeles refinery.[3] This crude oil is particularly explosive.[4] A Bakken crude oil rail accident blew up an entire town in 2013, killing many people.[5] Just last Saturday another crude oil train carrying this material exploded, requiring evacuation of an elementary school, and spilling oil into the Columbia River.[6] Bakken crude also contains high levels of volatile and toxic air contaminants and the DEIR should evaluate this threat. Tesoro's Project could also bring extreme Canadian tar sands crude oil to the LA refinery through the same Tesoro Savage ship terminal. These two crude oils cause increased greenhouse gases and harms to air, land, and water during extraction, and add explosion risks in storage and in refineries.

G1-85.2

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Tesoro made the following and many other statements about bringing Bakken crude to LA: *"When you think about formalizing competitive advantage and fully integrating our value chain, that is really what the Los Angeles Integration and Compliance Project is about. And when we think about creating value, we are not just thinking about advantaged crude oils in front of our refineries, but we're thinking about how that supply to the west coast of advantaged crude oils can change the shape of the crude oil supply/demand dynamics for the west coast. And that's what we are trying to accomplish through Vancouver Energy."* Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 09, 2015, p. 10, Keith Casey, Tesoro Corporation, EVP Operations
[4] U.S. Department of Transportation, 2014, available at: http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/1_2_14%20Rail_Safety_Alert.pdf
[5] http://www.earthisland.org/journal/index.php/eij/article/warning_highly_flammable/
[6] Oregon Public Broadcasting (OPB), 6/7/2016, New Spilled Crude Oil Discovered At Mosier Train Crash, http://www.opb.org/news/series/oil-trains/oregon-oil-train-mosier-derailment-cleanup-spill/

Response G1-85.2

As explained in Section 4.1.2.5 of the DEIR and Master Response 8, the Vancouver Energy Project is wholly independent from the proposed project and is undergoing separate environmental review by the Washington State EFSEC, which includes evaluation of transportation hazards. Additionally, as explained in Master Response 8, the Final EIS has not yet been issued for the Vancouver Energy Project, and the project has not been approved.

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Response G1-78.94, the Refinery is currently processing a blend of various crude oils and will continue to do so with or without the proposed project. The proposed project will not result in a substantial change in the crude oil blend processed by the Refinery.

The DEIR has analyzed the potential increase in crude oil processing of up to 6,000 bbl/day associated with the modification of the DCU H-100 heater permit description. The increase in crude oil processing rate is not related to any specific crude oil source. Master Response 4 explains that the Refinery's sources of crude oils have and will continue to vary with or without the proposed project. By using worst-case crude oil properties (see Response G1-78.157), the DEIR fully analyzed the potential impacts associated with storing various crude oils in the new and replacement storage tanks and with transferring various crude oils via the associated piping. There would be no additional impacts, beyond those analyzed in the DEIR, for the new and replacement storage tanks if different light or heavy crude oil is processed at the Refinery (see Sections 4.2.2.2 of the FEIR). The proposed project does not facilitate or encourage sourcing crude oil from any particular location. In other words, the improved offloading efficiency provides a benefit regardless of the type of crude oil transported by marine vessel.

Light and heavy crude oil is currently delivered, stored, and processed at the Refinery and will continue to be delivered, stored, and processed with or without the proposed project. The impact analysis in the DEIR accounts for the variety of crude oils that have been and will be handled by the Refinery. For example, the TAC concentrations of crude oils in storage tanks associated with the proposed project were based on a worst-case hybrid analysis of the toxic content of the crude oils currently and potentially processed at the Refinery, including Bakken and heavy Canadian crude oil. The hybrid TAC speciation was prepared by selecting the highest concentration of each toxic compound from the entire speciated data set of all the crude oils analyzed.

There have been previous volatility issues associated with the transport of Bakken crude oil. However, regulations have since been adopted that require a reduction in volatility of Bakken crude oil that is transported. For example, in December 2014, the Industrial Commission of North Dakota issued an order regarding conditioning of Bakken crude oil and limiting the RVP of crude oil provided for transport to 13.7 RVP. Thus, Bakken crude oil transported to the West Coast will be pipeline quality (i.e., qualified for safe transport) and will not have as high a vapor pressure as the Bakken crude oil produced at the wellhead. As with other U. S. crude oil production operations, the order adopted by the State of North Dakota will require that crude oil production facilities remove a significant portion of the light ends (ethane, propane, butane and pentane) prior to offering the crude oil for shipment to refineries for processing.

Because of Bakken crude oil's purported volatility, concerns were raised in the media as to whether Bakken crude oil was properly classified as a Class 3 hazardous material under U.S. DOT regulations. A Class 3 hazardous material is generally a flammable or combustible liquid that does not meet the regulatory classification requirements for other hazardous characteristics, such as toxicity, corrosivity, radioactivity or explosiveness. However, those concerns have since been resolved by repeated analysis and testing that demonstrates Bakken crude oil to be a Class 3 hazardous material, similar to other light sweet crude oils. After considering the information, the PHMSA Deputy Administrator testified to Congress that Bakken crude oil is accurately classified as a Hazard Class 3 Flammable Liquid.[294] This is consistent with the sampling and

[294] Written statement of Timothy P. Butters Before the Subcommittees on Energy and Oversight Committee on Science, Space and Technology, U.S. House of Representatives at page 12 (Sept. 9, 2014).

testing Tesoro has completed on Bakken crude oil. Therefore, Bakken crude oil has properties similar to other light crude oils, and is not classified as explosive.

The Refinery did not process large amounts of Bakken or Canadian heavy crude oil in the baseline period. This observation, however, is not relevant to the analysis in the DEIR. As explained in subsequent responses, which are listed in Table 78-94.1, Bakken and heavy Canadian crude oils are similar to other light and heavy crude oils currently processed by the Refinery. As described in Master Response 4, and Response G1-78.150, in the future, as now, any Bakken or heavy Canadian crude oils processed would have to be combined with other crude oils to create a crude oil blend that matches the Refinery's processing capabilities and permit limitations. This is what has occurred with Bakken, heavy Canadian, and many other heavy and light crude oils that were utilized in the baseline period, and is what will continue after implementation of the proposed project. Any increased use of Bakken or heavy Canadian crude oils at the Refinery would not be caused by the proposed project. The proposed project's impacts were analyzed in detail using worst-case assumptions (e.g., the maximum vapor pressure of crude oil allowable by SCAQMD rules), which accounts for any impacts from increased use of Bakken or heavy Canadian crude oil. Response G1-78.111 specifically addresses crude oil corrosivity. Responses G1-81.65 and G1-81.67 address greenhouse gases and crude oil production.

The comment also refers to derailment of a train carrying Bakken crude oil in Mosier, Oregon and another unidentifiable derailment. As explained in Response G1-81.57, there are no proposed project modifications to bring crude oil by rail to the Refinery. Thus the Mosier derailment and other derailments are not relevant to the DEIR analysis or the proposed project. Responses G1-81.65 and G1-81.67 explain that the DEIR does not need to analyze the environmental impacts from crude oil production because the proposed project will not cause any changes to that industry.

The comment includes a slide of a map that the comment claims is ". . . Tesoro's map laying out its plans to transport Bakken crude oil to L.A." The map is titled "Rail Costs to Clear Bakken," and shows ranges of costs to transport Bakken crude oil to various locations on the West and East Coasts of the U.S. The map includes a clarifying subtitle "West and East Coasts clearing destinations for Bakken crude oil." There is no reference on the slide or map to any definitive plans to transport Bakken crude oil to any destination, or to any destination in particular or increased amounts.

The claims in Footnote 3 alleging that Tesoro's corporate statements to investors reflect a different project objective (i.e., to change the crude oil blend processed by the Refinery) have taken those corporate statements out of context. There are no corporate statements that state or even imply that the proposed project is designed to facilitate a change in the crude oil blend processed by the Refinery. The comment pieces together unrelated statements and draws an incorrect conclusion. The statement cited by Footnote 3 of the comment is explained in detail in Response G1-78.136. The quotation is from an Analyst and Investor Day presentation. As

explained in Attachment C, the Declaration of Douglas Miller,[295] it is important to note that analyst and investor discussions present a high level overview of strategic projects that Tesoro plans to implement at the time of the respective presentations. In fact, just prior to the selected quote, Mr. Casey (Tesoro's Executive Vice President, Operations) stated, "Now, as I told you, I also get to update you on some strategic projects, and we have talked about a few of these for the last bit, but really give you some news on the exciting progress that we are making on each of these."[296] Clearly, Mr. Casey is talking about more than one strategic project. Simply because the projects are summarized together in an overview is not an indication that the projects are related. The quotation references two separate projects—the proposed project and the Vancouver Energy Project—as each helping Tesoro accomplish general corporate goals, but the speaker never links the two projects together or states that Tesoro has plans to change the crude oil slate at the Refinery. The proposed project will not result in a significant change in the crude oil blend processed by the Refinery except as analyzed in the DEIR.

The comment and Footnote 6 refer to the derailment of a train carrying Bakken crude oil in Mosier, Oregon. Because there are no proposed project modifications to bring crude oil by rail to the Refinery, the Mosier derailment is not relevant to the DEIR analysis or the proposed project. The Federal Railroad Administration's preliminary report identified a railroad track issue as the cause of the Mosier incident[297]; therefore, there are no resulting mitigations that would need to be considered for the proposed project.

The DEIR does not analyze crude oil production because the proposed project will not cause any changes to that industry. Tesoro does not own the crude oil production facilities for any of the crude oil that will be purchased to supply its Refinery. Therefore, the detailed information necessary to accurately quantify the GHG impacts from crude oil production facilities is not available and would require speculation to quantify the impacts. GHG emissions resulting from oil production are the responsibility of the crude oil producer.

The FEIR fully analyzed the potential impacts of the proposed project with respect to greenhouse gas emissions in Section 5.2.2.3 and hazards in Section 4.3.2.

Comment G1-85.3

> The DEIR and Title V permit also failed to count air emissions from flaring during startup, shutdown, and maintenance, other air emissions increases, and failed to set permit conditions that would prevent these increased emissions. The SCAQMD's public records show that Tesoro Refinery was issued 66 Notices of Violation from 2000 to 2015. Our communities' health and safety must not be put at higher risk when Tesoro cannot demonstrate a consistent record to operate within the law.
>
> G1-85.3
>
> G1-85.3 cont'd.

[295] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

[296] Thomson Reuters Streetevents Edited Transcript, TSO- Tesoro Corporation 2015 Analyst and Investor Day, December 9, 2015, 2:00PM, at page 10.

[297] https://www.fra.dot.gov/eLib/details/L18393#p1_z50_gD_lAC, accessed November 7, 2016.

Response G1-85.3

Startup and shutdown emissions, as well as emergency flaring, are discussed in detail in Master Response 15.
As explained in Master Response 15, the Refinery strives for startups, shutdowns, and maintenance without flaring. In any event, there are no new process units associated with the proposed project that would be expected to flare during startup or shutdown. No additional permit conditions are needed to control startup and shutdown emissions.

Emission changes as a result of the proposed project have been fully analyzed and are discussed in Section 4.2 of the FEIR. An emissions summary can be found on pages 4-16 through 4-18 in Table 4.2-4. Further, Title V permit limits will be equal to or more restrictive than the emissions analyzed in the DEIR.

The comment also refers to "other air emission increases" that were not accounted for in the DEIR and Title V permit. The comment lacks specificity. Without further detail regarding these other air emissions, a specific response cannot be provided.

Comment G1-85.4

Our community is already overburdened with air pollution and dangers of petroleum storage, pipelines, and refining. University of Southern California studies show that improvements in air quality have improved the respiratory health of children in our region[7]. Improvements in air quality come with advanced technology, clean energy sources and forward-thinking solutions. We must not revert to outdated practices that will pollute our air and harm our children's lungs. We want to stop the expansion of oil refineries, to start building our safe, healthy, and clean energy future, and to have a fair public process.

[7] http://usceh.blogspot.com/p/infographic-southern-california.html

G1-85.4

Response G1-85.4

As explained in Section 4.2.2.2 of the FEIR, upon completion, the proposed project will result in regional and local reductions in CO emissions and local reductions of operational NOx, SOx, PM10, and PM2.5 emissions. The increase in operational VOC emissions associated with the proposed project was found to be less than significant. The proposed project emissions are described in detail in Section 4.2 of the FEIR and are summarized in Table 4.2-4 (see pages 4-16 through 4-18). The proposed project will result in local overall reductions in GHG emissions, as described in Section 5.2 of the FEIR and summarized in Table 5.2-8 (see page 5-26).

The proposed project's local health effects have been analyzed and are discussed in Master Response 3. Potential hazard impacts, including those related to material storage and pipelines, are explained in Master Response 9. The proposed project is not an expansion of the Refinery. See Response G1-27.1 and Master Responses 6 and 7 for a detailed description of the potential 6,000 bbl/day crude oil capacity increase associated with the proposed project.

The proposed project has complied with the public process required by CEQA Guidelines § 15087. As explained in detail in Master Response 1, the DEIR was circulated for an extended length of time. The public comment period closed on June 10, 2016, after two extensions. A

94-day public review and comment period (March 8, 2016 through June 10, 2016) was provided, which exceeds CEQA requirements. A public hearing on the Title V permit and public meeting on the DEIR was held on May 17, 2016. Copies of the DEIR were made available in neighborhood public libraries. Notices were published and distributed for the original public comment period, the two extensions, and the public hearing on the Title V permit and public meeting on the DEIR.

In addition, Tesoro independently offered and provided community outreach to over 100 entities including public agencies, community organizations, neighborhood organizations, business associations, and other interested parties to explain the scope of the proposed project and the potential environmental effects of the proposed project. The community meetings were held on April 4, 11, and 14, 2016 in Carson, Wilmington, and Long Beach, respectively. Tesoro has identified that a total of 277 people attended the meetings.

Comment Letter No. G1-86

COMMUNITIES FOR A BETTER ENVIRONMENT

East Yard Communities For Environmental Justice

CFASE

EARTHJUSTICE

June 10, 2016

Dr. Jillian Wong
C/O Office of Planning, Rule Development, and Area Sources/CEQA
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765
jwong1@aqmd.gov

Re: Tesoro Refining and Marketing Company LLC Los Angeles Refinery Integration and Compliance Project – State Clearinghouse 2014091020

Dear Dr. Wong:

We write to you today to submit comments on the Draft Environmental Impact Report ("DEIR") for the Tesoro Refining and Marketing Company LLC Los Angeles Refinery Integration and Compliance Project ("Project" or "LARIC"), and associated permit applications before the South Coast Air Quality Management District ("SCAQMD") for approval. Joining in these comments are Communities for a Better Environment ("CBE"), East Yard Communities for Environmental Justice ("EYCEJ"), the Coalition for a Safe Environment ("CFASE"), and Earthjustice. Overall, this is a deeply concerning project that will add additional environmental impacts in an already overburdened community. Given these problems, we suggest that the SCAQMD address all of the concerns stated in this letter and additional submissions. In addition, the SCAQMD should undertake efforts to make sure the Tesoro Refinery fully protects the community surrounding these facilities. G1-86.1

Commenters also attach a technical report prepared by Julia May. This report will be referred to as "May Technical Report" in these comments. We incorporate by reference the May Technical Report and all the comments in that attachment. In addition, we respectfully request that the SCAQMD respond to the entire contents of the May Technical Report in its response to comments, in addition to all the comments in this letter. G1-86.2

I. COMMUNITY AND ENVIRONMENTAL SETTING.

Noticeably absent from the entire DEIR is the true context for this project. This project is taking place in one of the most disproportionately impacted communities in all of California. The following map shows that both locations are either in an area designated by California as the top 25% of most disadvantaged communities (i.e. Wilmington location) or surrounded on all sides by areas designated in the top 25% of most disadvantaged communities (i.e. Carson location). G1-86.3

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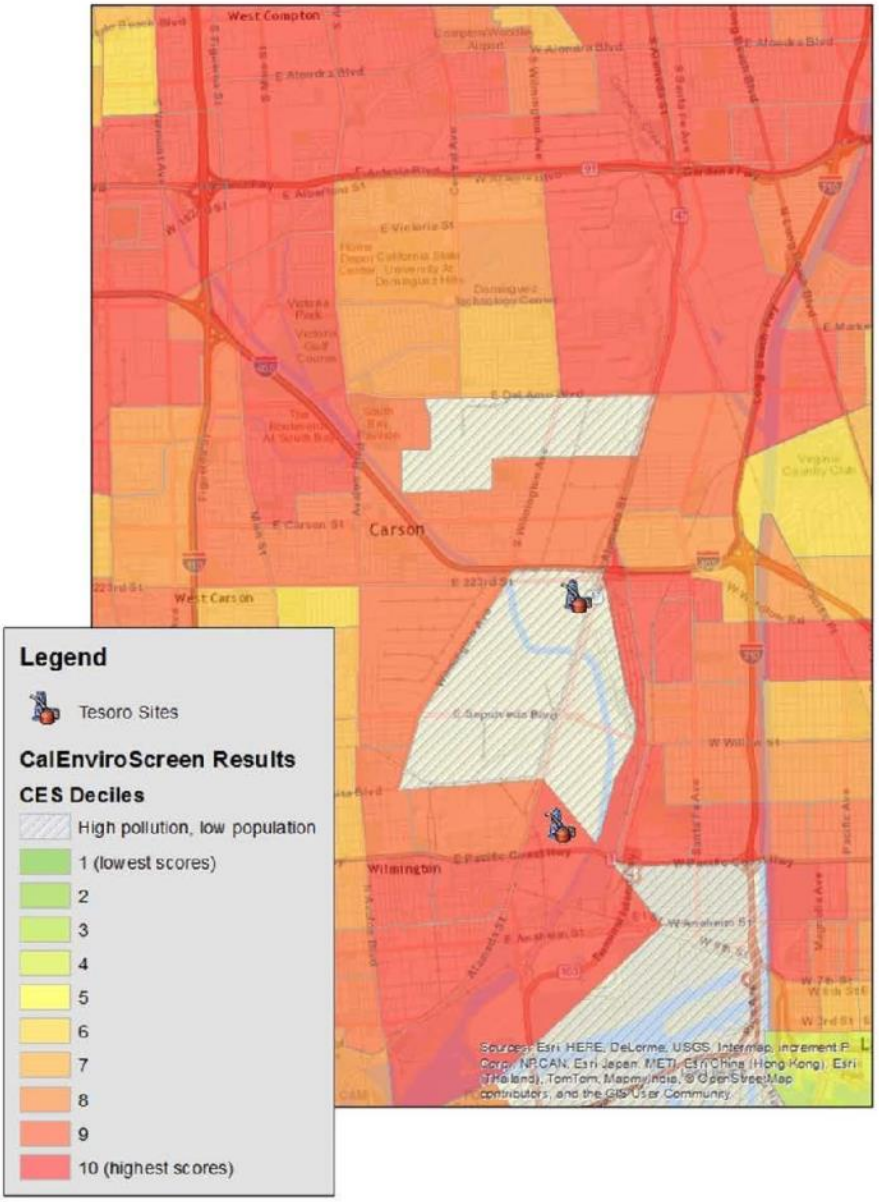
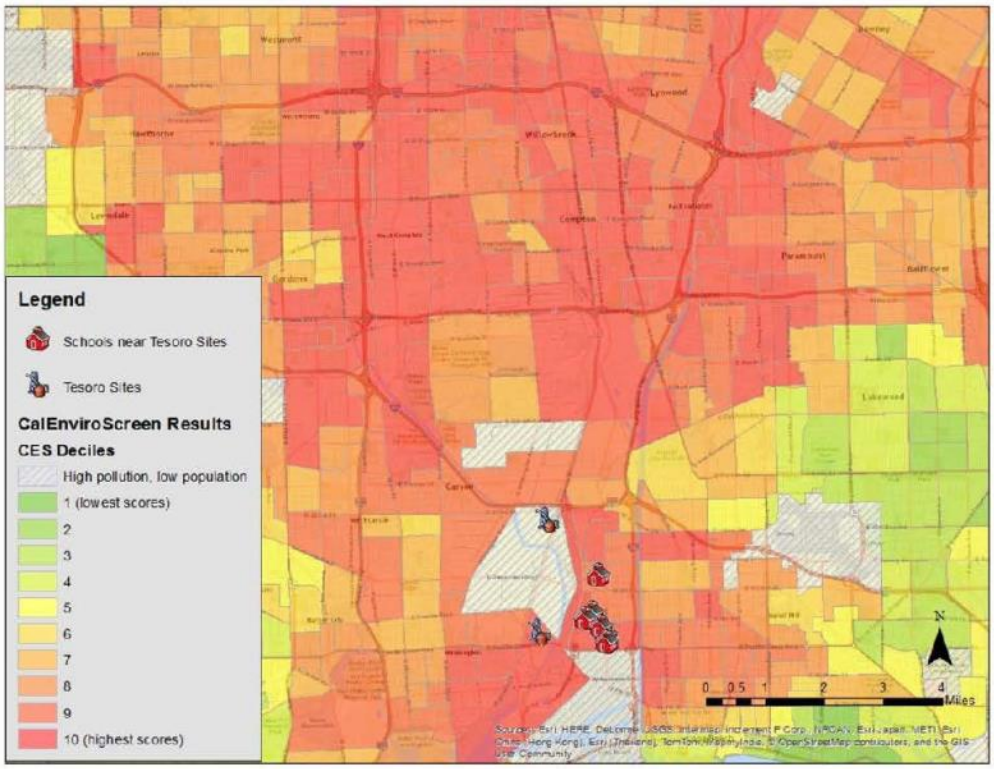


In addition, many sensitive sites are located in close proximity to this project as shown by the following map.

G1-86.3 cont'd.



G1-86.3 cont'd.

In fact, the DEIR does not include meaningful analysis of environmental justice or even acknowledge the existence of the new CalEnviroScreen tool developed by California's Office of Environmental Health and Hazard Assessment (OEHHA). This environmental justice context should be provided for decisionmakers, and the DEIR is flawed for excluding this critical information.

II. MAGNITUDE OF THE PROJECT.

As the May Technical Report establishes, this Project is unprecedented in scope. Moreover, its location in a dense urban area raises concerns over the health and safety of adjacent residents. Importantly, this Project merges two refineries to create the largest refinery on the west coast.[1] The Project also combines the two worst polluting facilities in California for causing disparate PM10 impacts.[2]

G1-86.4

[1] May Technical Report, § I
[2] May Technical Report, §VII

Top 10 Facilities Polluting Disproportionately in Communities of Color

Rank	Facility Name	City
1	BP Carson Refinery	Carson
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)
3	Paramount Refinery	Paramount
4	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)
5	ExxonMobil Torrance Refinery	Torrance
6	Chevron Richmond Refinery	Richmond
7	Malburg Generating Station (Vernon Power Plant)	Vernon
8	ConocoPhillips Carson Refinery	Carson
9	Valero Wilmington Refinery	Wilmington (Los Angeles)
10	California Portland Cement Company Colton Plant	Colton

G1-86.4 cont'd.

Even beyond the large pollution loads imposed on adjacent communities from these facilities, the Project entails storing, transporting and processing dangerous products, including Liquefied Petroleum Gas and other oil products. Thus, in addition to pollution and other impacts, these projects impose immense safety risk to residents in the project area. The DEIR and permit conditions do not adequately assess and mitigate the large risks that are imposed on adjacent communities.

G1-86.5

III. THE DEIR DOES NOT DISCLOSE THE FULL SCOPE OF THE PROJECT AND FAILS AS AN INFORMATIONAL DOCUMENT.

The Project Description is inadequate because it fails to disclose the full scope of the Project's nature and objectives, including enabling a shift to a different quality of crude oil feedstock at the integrated refinery. The description also obscures the inextricable link between this Project and Vancouver Energy, resulting in an improper piecemealed analysis. The incomplete Project description and undisclosed Project components result in wholesale omission or underestimation of significant and adverse impacts, including pollution emissions and elevated hazard risks. The DEIR is therefore fatally flawed and must be withdrawn.

G1-86.6

A. The DEIR Relies On an Inaccurate Project Description and Violates CEQA's Information Disclosure Mandate Requiring a Comprehensive Description of the Entire Project That Allows the Public to Ascertain the Nature And General Magnitude of Environmental Impacts.

In order for an environmental document to adequately evaluate the environmental impacts of a project, it must first provide a comprehensive description of the project itself. "An accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity."[3] The description must not only be accurate, but also "stable and finite" to be "an informative and legally sufficient EIR."[4] While extensive detail is not necessary, the law mandates that the project description should include detail sufficient to

G1-86.7

[3] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713, 731 (internal citation and quotation omitted).
[4] *Id.* at 730 (internal citation and quotation omitted).

ascertain the nature and general magnitude of environmental impacts.[5] Thus, a deficient project description renders the analysis of significant environmental impacts inherently unreliable. As a result, courts have found that, even if an EIR is adequate in all other respects, the use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency did not proceed in a manner required by law.[6]

G1-86.7 cont'd.

The DEIR's Project Description discloses a narrow set of objectives limited to furthering the integration of the Carson and Wilmington Refinery operations through process modifications.[7] It states that the Project will "improv[e] process efficiency," "[r]ecover[]and upgrad[e] distillate range material from FCCU feeds[,]" "[c]omply[] with federal, state, and local rules and regulations[,]" and "[i]mprov[e] efficiency of water-borne crude oil receipt and marine vessel unloading" by expanding barrel tank capacity.[8] The DEIR states that the Project will have a "small impact on crude oil and feedstock throughput . . . . capability[,] increase[ing] approximately two percent or 6,000 barrels per day (bbl/day) as a result of the proposed project."[9] These Project components, however, are actually critical pieces of an undisclosed broader purpose—to enable the Refinery to process cheaper North American Bakken and potentially Canadian Tar Sands Crude Oil, and effectuate Tesoro's business plan to switch its crude oil stock in its west coast refineries. The DEIR's seemingly benign project description, therefore, obscures a key purpose of the Project.

G1-86.8

The May Technical Report evaluates the DEIR's factual representations and conclusions. May's analysis outlines the discrepancies, inaccuracies, and omissions of the DEIR, and point to the much broader crude-switch Project purpose with significant impacts. May concludes that a switch to Bakken and Canadian Tar Sands Crude oil is enabled by the Project, including by providing tank expansions to accommodate the new crudes; connecting transport through piping; and through addition of extensive sulfur contamination removal equipment (hydrodesulfurization and hydrotreaters, discussed below) that can remove higher sulfur content from Canadian crude. While the DEIR identifies benefits of these activities (such as reducing ship port time), it fails to disclose the Project impacts that would occur due to the crude oil switch.

As concluded by May, the Project Description is further deficient in failing to disclose the true scale of the Project. The DEIR contradicts Tesoro's public statements about the Refinery's throughput capacity. The Refinery's size is a basic and fundamental characteristic that implicates the purpose of the Project and its significant impacts. Accordingly, the DEIR cannot proceed until the basic facts of the Refinery's size are effectively identified. Moreover, the DEIR mischaracterizes the underlying reason for Tesoro's shutdown of the Wilmington FCCU. The DEIR inaccurately asserts that one purpose of the Project is to disable the FCCU to reduce emissions. The FCCU shutdown, however, is a preexisting requirement independent of Tesoro's efforts to further integrate the Carson and Wilmington refineries. It is a binding commitment in which Tesoro agreed to replace the FCCU as a condition of obtaining government approval for its acquisition of the Carson refinery. Therefore, a key purpose for shutting down the FCCU is to

G1-86.9

[5] *See* CEQA Guidelines, §15124 (requirements of an EIR).
[6] *San Joaquin Raptor/Wildlife Rescue Center*, 27 Cal. App. 4th at 730.
[7] DEIR, at 2-1 to 2-4.
[8] DEIR, at 2-3 to 2-4.
[9] DIER, at 2-2.

comply with the acquisition requirements. The Project description is therefore deficient for these additional reasons.

Based on these and other reasons, as described below, the Project Description renders the DEIR woefully inadequate in light CEQA's environmental review requirements.

G1-86.9 cont'd.

a. The project description fails to disclose Tesoro's shift to a different quality crude feedstock for its Los Angeles and other West Coast refineries.

CEQA requires that an environmental review document for a refinery project disclose whether proposed project modifications will enable the refinery to process different crude, if a crude slate change is reasonably foreseeable.[10] In *Communities for a Better Environment v. Richmond* (hereinafter "*Richmond*"),[11] petitioner argued that an EIR violated CEQA's mandate where the refinery project EIR disclosed only equipment changes, but failed to disclose that such modifications would significantly increase Chevron's ability to process lower quality, heavier crude, compared with the crude slate the refinery traditionally processed. The FEIR in *Richmond* dismissed the petitioner's comments on the ground that the project would not alter the refinery's design to process the advantaged crude. The court of appeal disagreed with the lead agency, holding that reasonably foreseeable consequences of a project, such as a crude slate switch, must be disclosed and evaluated in the EIR.[12] The DEIR here is similarly flawed and cannot pass muster under CEQA.

Tesoro is currently in the process of implementing a series of projects to carry out a business plan that allows a switch to refining what it known as "advantaged crude." These crude oil feedstocks are more economically viable as a result of challenges in accessing and transporting them. Both tar sands and Bakken are examples of such "competitively priced," cost-advantaged crudes because they are stranded, with no pipeline access and must be delivered, at least initially prior to any refining, by rail. Tesoro has been explicit in setting forth its West Coast strategy to access and refine these crudes by transporting them to Washington by rail, and then to the Los Angeles Refinery by ship.

G1-86.10

Tesoro has expressed a clear priority to switch to refining Bakken and potentially Canadian Tar Sands at the Los Angeles Refinery, and the Project implements that plan by making modifications that enable processing of the different crude. There is ample evidence showing that the Project will enable the refinery to begin processing Bakken and potentially Canadian tar sands crude oil, as discussed below, yet the DEIR both omits and negates this information. Of course, unless the DEIR *first* discloses the extent of replacement of feedstock

[10] *Communities for a Better Environment v. City of Richmond* (2010) 184 Cal.App.4 70, 89.
[11] *Id.* at 83.
[12] The court thus ruled that the EIR was deficient because it failed to disclose the foreseeable crude switch. The California Attorney General and the Governor's Office of Planning Research have maintained that an EIR fails to meet CEQA's requirements where it obscures the project's enabling of a refinery to process heavier crude. *See* Letter from the Office of the Attorney General to the City of Pittsburg Planning Department, Jan. 15, 2013; Letter from the Governor's Office of Planning and Research to the City of Pittsburg Planning Department, Dec. 3, 2013.

that the Project enables, it is impossible to provide any intelligent evaluation of the potential environmental effects and risks to community and worker health and safety resulting from refining advantaged crude in the Los Angeles refinery.[13] The DEIR's omission of the enabled switch to crude oil feedstock and blend violates CEQA's project description requirements and prohibits analysis of its significant impacts.[14]

G1-86.10 cont'd.

b. Tesoro investor and public statements evidence that the Project's purpose is to enable the Los Angeles refinery to process advantaged crudes as part of its West Coast crude slate switch plan.

In contrast to the DEIR's silence, Tesoro has consistently made known its plan to enable its West Coast refineries, including the Los Angeles Refinery, to process lower quality oil feedstock, including highly volatile crude from the Bakken shale play in North Dakota. May's Technical Report details and assesses Tesoro's public statements on the matter.[15] Tesoro unequivocally told its investors that the purpose of the Project is to obtain a competitive edge by integrating its business chain and placing "advantage crude oils in front of [the] refineries," including Carson/Wilmington, by changing the crude oil supply and demand dynamics in the West Coast. In December 2015, it explained that:

> "formalizing competitive advantage and fully integrating our value chain, that is really what the Los Angeles Integration and Compliance Project is about. And when we think about creating value, we are not just thinking about advantaged crude oils in front of our refineries, but we're thinking about how that supply to the west coast of advantaged crude oils can change the shape of the crude oil supply/demand dynamics for the west coast. And that's what we are trying to accomplish through Vancouver Energy."[16]

G1-86.11

Indeed, Tesoro and industry communications are replete with explainations about the direct connection of the LA Refinery integration project with its West Coast crude oil supply project–the Vancouver Energy Project in Washington–which it identifies as "the most efficient route to the West Coast for Bakken crude oil."[17]

In 2013, industry literature reported that:

> Tesoro's "refining capacity[,] concentrated in California[,] . . . has not realized the benefit of the ongoing Mid-Continent discounts

[13] *See Richmond*, 184 Cal.App.4 at 89.
[14] *See Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1355 ("the failure to include relevant information precludes informed decisionmaking and informed public participation, thereby thwarting the statutory goals of the EIR process").
[15] May Technical Report, § II(B).
[16] Edited Transcript TSO - Tesoro Corporation 2015 Analyst and Investor Day, December 9, 2015, at 10.
[17] Tesoro Presentations webpage, weblink: Morgan Stanley Corporate Access Day, 5/12/16, Slideshow entitled: *Driven to Create Value, Morgan Stanley Refining Corporate Access Day, May 2016*, Slide 13 &15, available at: http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.

> that many of its peers have. . . . That said, past and future investments as well as the addition of infrastructure should allow it to capture amounts of cost-advantaged feedstock similar to its peers. . . . [I]t has invested in rail facilities to move 50 mb/d of Bakken crude west to its Anacortes, Wash., refinery[.] [L]ight and heavy crude in the Mid-Continent will create an opportunity and economic incentive to rail both types of crude to its three California refineries, increasing their throughput of cost-advantaged crude. In fact, Tesoro already has plans in place to do so." "Specifically, Tesoro can dramatically improve the performance of Carson by optimizing its crude slate with light crude from the Bakken. . . . Tesoro should gain further advantages from integrating Carson with the Wilmington refinery."[18]

G1-86.11 cont'd.

While in 2013, Tesoro had not realized the cost benefit of Mid-Continent discounts that its industry "peers" had gained, by May 2016, Tesoro's Chairperson and CEO reported that throughout its new distribution of Bakken crude to the West Coast, Tesoro "will be able to capture the refining value because of the *displacement of crudes that we run today with Bakken crude oil*, which we've clearly stated in the past is between $3 to $5 a barrel on average."[19]

Between those years, Tesoro made headway in carrying out its plan to displace its west coast refineries' crude slate with Bakken. At a Feb. 2014 Simmons Energy Conference, Tesoro's presentation included the following slide showing its rail and shipping distribution from North Dakota to the west coast refineries, including the Los Angeles refinery:[20]

[18] *See* Julia May 2014 Expert Report, at 7-8; Morningstar report, *Tesoro aims to increase throughput of domestic crude over the next few years*. July 24, 2013, *available at* http://analysisreport.morningstar.com/stock/archive?t=TSO&region=USA&culture=en-US&productcode=MLE&docId=604033.

[19] Edited Transcript TSO - Q1 2016 Tesoro Corp Earnings Call May 05, 2016, p. 19 (emphasis added), *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-transcriptsarchive.

[20] Transformation through Distinctive Performance, Simmons Energy Conference, February 2014 , Slide 15.

Tesoro stated that the Washington rail-to-ship project provides "[f]lexibility to deliver to all West Coast refineries," and specified that the cost of rail to the state of Washington, and then by ship to California is "[c]ompetitive with direct rail cost to California." Tesoro's explanation of its "Advantaged Feedstock Opportunity" in Los Angeles consists of shifting crude oil feedstock from what was "currently up to 15% California Heavy" crude to "*[p]otentially up to 50% California Heavy and Bakken*" crude oil.[21] It then boasted that "Bakken crude oil yields 14% to 16% more gasoline and distillate than ANS."[22] This evidence undermines the DEIR's assertion that "[t]he Carson and Wilmington Operations current [sources of] crude oil and feedstock . . . are not expected to change as a result of the proposed project."[23]

G1-86.11 cont'd.

In July of 2014, Tesoro reported that it was "making good progress on the integration of the [Carson and Wilmington] facilities."[24] It explained:

> We are off the interim crude oil supply agreements and continue to focus on improving the optimization of the crude oil slate. We expect to continue to run Basrah and A[N]S but are continually increasing the variety of crude oil we run. . . . The Wilmington portion of the facility can now access the Carson inbound crude oil logistics network which improves our flexibility. During maintenance activity at the Anacortes refinery in the quarter, we were able to move some barrels of Bakken down to our

[21] Simmons Energy Conference, *Transformation through Distinctive Performance,* February 27, 2014, at 13, *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.
[22] *Id.* at 16.
[23] DEIR, at 2-27.
[24] Edited Transcript TSO - Q2 2014 Tesoro Corp Earnings Call, July 31, 2014, p. 5, *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.

> Los Angeles refinery and realized refinery values relative to A[N]S similar to those that we experienced at Anacortes."[25]

In other words, Tesoro explained that it ended its oil supply contracts and was focused on increasing crude supply variety. The integration of the refineries allowed improved flexibility to do just that, providing as an example the Wilmington refinery's access to Bakken, which it successfully refined at a value similar to ANS crude. Again, this evidence shows that, contrary to the DEIR's project description and statements concerning crude slate, Tesoro's objective is to enable the LA refinery to process a different crude feedstock.

G1-86.11 cont'd.

c. The Project is inextricably related to the Tesoro Savage Vancouver Energy Terminal in Washington and Tesoro's objective to bring Bakken crude to its west coast refineries, with options for Canadian crude.

The DEIR's Project Description improperly omits the Project's full scope and nature by failing to disclose its true relationship to the Vancouver Energy terminal and aim to carry out the latter's purpose.

The *Vancouver Energy Terminal* in Vancouver, Washington,[26] a joint venture by Tesoro/Savage on the Columbia River, is a crude-by-rail to oil tanker terminal. The Vancouver Energy website states that the terminal project's purpose is to accept midcontinent North American crude, including Bakken, and then transferred to vessels to be shipped to West Coast oil refineries.[27] The Draft Environmental Impact Statement (DEIS) for the Tesoro Savage terminal states that "[s]tarting in 2017, . . . the most likely sources would be northern mid-continent crude oil produced in North Dakota and Montana, and in Canada."[28]

Dr. Phyllis Fox's June 10, 2014 expert report on the Draft Negative Declaration for the Tesoro Storage Tank Replacement and Modification Project found that "[t]he CEO of Tesoro, Greg Goff, has indicated that the Los Angeles Refinery can take the entire shipment [from the Vancouver Terminal because] [t]here are 'no restrictions on how much [the LA Refinery] can take[.]'"[29] This evidence shows that Tesoro's intention is to enable the LA Refinery to access and process the Bakken and tar sands crude oil from the Vancouver Terminal.

G1-86.12

The DEIR's statements denying that the proposed Vancouver Terminal is related "to the replacement of crude oil tanks or the Tesoro Refinery Integration and Compliance project" on the ground that the Vancouver project "could go forward with or without the" Integration Project, is inapposite.[30] The question here is whether the this Project enables it to process a different crude slate, which must be answered in the affirmative. Based on evidence in the

[25] Edited Transcript TSO - Q2 2014 Tesoro Corp Earnings Call, July 31, 2014, at 5, *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.
[26] Not to be confused with Vancouver Canada, which also has oil terminals on the West Coast.
[27] https://www.vancouverenergyusa.com/.
[28] Tesoro Savage DEIS, Fact Sheet, *available at* http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20PAGE.shtml.
[29] May Technical Report, Attachment 13, at 11 (hereinafter "Fox Neg. Dec. Report").
[30] DEIR, at 4-5.

record, it is also clear that Tesoro intends for the Vancouver Terminal to supply the Bakken and potentially Canadian Tar Sands crude to the LA refinery.

G1-86.12 cont'd.

d. The LA Refinery is capable of refining a crude blend of Canadian and Bakken to approximate its current Alaska North Slope yields.

The DEIR also argues that the LA Refinery is physically constrained from processing Bakken crude oil.[31] Not so. As the DEIR admits, the issue is not whether the LA Refinery can process Bakken crude oil and other light sweet crude *type* oils, but rather, whether these crude oils can be prepared into a "blend" that works with current refinery configurations. Tesoro's own evidence shows that Bakken oil can indeed be blended for successful processing at the LA Refinery.[32] The DEIR, however, obscures this fact in violation of CEQA's environmental review requirements.

The DEIR explains that "[t]here are limitations on the types of crude oil that can be processed in the [LA] Refinery due to the design limitations and capacities of the processing units."[33] Accordingly, "[c]rude oil that is purchased is blended to meet criteria specific to Carson or Wilmington Operations . . . [and] complement specific refinery configurations." As an example, because "the Carson Operations have been designed to run primarily Alaska North Slope (ANS) crude oil, which is in declining availability [,] the Carson Operations blend crude oils to have properties similar to ANS crude oil."[34]

G1-86.13

As explained in the May Technical Report, the oil industry has specifically identified a blend of cost-advantaged Bakken and Canadian crude oils to approximate and serve as a replacement to ANS crude oil.[35] May concluded that using such a blend at the LA Refinery would replace dwindling supplies of lighter, low sulfur ANS crude oil used in the range of 100,000 barrels per day (bpd).[36] Contrary to the DEIR's assertions,[37] it is not necessary for the LA Refinery to undergo equipment and design modifications in order to refine Bakken and Canadian crude. Because the blend would approximate the current ANS API, the problems identified by the DEIR[38] are inapposite.

In fact, the evidence shows that Tesoro has already tested and ascertained that the LA Refinery *is* capable of processing Bakken in a manner that "complement[s] refinery

[31] DEIR, at 4-5 to -6.
[32] Edited Transcript TSO - Q2 2014 Tesoro Corp Earnings Call, July 31, 2014, p. 5 (During maintenance activity at the Anacortes refinery in [2014], [Tesoro] . . . move[d] some barrels of Bakken down to [the] Los Angeles refinery and realized refinery values relative to A[N]S[.]").
[33] DEIR, at 2-16.
[34] *Id.*
[35] May Technical Report, § III(C) (citing The North American Crude Boom: How Changing Quality Will Impact Refiners, John R. Auers, Turner, Mason & Company, Platts Crude Marketing Conference, March 1, 2013, Houston, available at: http://www.turnermason.com/wp-content/uploads/2013/05/North_American_Crude_Boom-platt-2013.pdf.).
[36] May Technical Report, § III(C).
[37] DEIR, at 4-5.
[38] *See* DEIR, at 2-16

configurations" and provides "properties similar to ANS crude oil."[39] "During maintenance activity at the Anacortes refinery in [2014], [Tesoro] . . . move[d] some barrels of Bakken down to [the] Los Angeles refinery and realized refinery values relative to A[N]S[.]"[40] The LA Refinery can and has already successfully refined Bakken, and the DEIR's assertions to the contrary strain credulity.

The DEIR must be withdrawn and recirculated to reflect the Project's enabling of processing of Bakken and Canadian crude, and to inform the public of its impacts. May's Technical Comment concluded that the blend's approximation of the ANS API gravity does not mean that no new impacts would result from the advantaged crude switch.[41] Rather, the new blend would introduce new environmental impacts due to other crude oil characteristics. For example, explosion hazards would increase from Bakken crude introduction, as would additional content of toxics, such as benzene, not investigated in the DEIR discussion. Further, increased sulfur mass from Canadian crudes would increase corrosion hazards and increase acutely hazardous sulfur gases, such as hydrogen sulfide. The DEIR ignores these significant impacts, and thus violates CEQA.

G1-86.13 cont'd.

e. The DEIR improperly ignores tank permit changes that specifically facilitate crude slate changes.

The Project seeks to modify and construct new crude storage tanks that provide for over 3.4 million barrels (bbls) of new storage, a 153 million bbl/year increase in throughput based on the tanks alone.[42] The increased storage capacity, as summarized by the May Technical Report, amounts to twice the size of the entire existing crude storage at Wilmington (1.7 million bbls).[43] May's technical analysis of the Project's storage tank component concludes that, contrary to the DEIR's statements, these modifications are not solely for faster ship offloading. May explains that the tank expansion also allows for an "increased throughput" that is itself "greater than the entire existing refinery currently processes."[44] This substantial volume of throughput would need to be transferred from the tanks to elsewhere, meaning that Tesoro will either use or sell — Project purposes that have not been disclosed or evaluated for impacts.[45]

G1-86.14

According to May's Technical Report, the changes sought by the Project's storage tank permit application may enable new storage capacity for advantaged crudes.[46] The high vapor pressure limits disclosed by the original 2014 Negative Declaration accommodated Bakken crude.[47] The DEIR omits the modified high vapor pressure limits, although the same tanks with

[39] DEIR, at 2-16.
[40] Edited Transcript TSO - Q2 2014 Tesoro Corp Earnings Call, July 31, 2014, at 5.
[41] May Technical Report, § III(C).
[42] May Technical Report, § III(E).
[43] May Technical Report, § III(E).
[44] May Technical Report, § III(E).
[45] May Technical Report, § III(E).
[46] *See* May Technical Report, § III(E).
[47] May Technical Report, § III(E).

the same new modifications are part of this Project, and may very well maintain the proposed high vapor pressure limit.[48] If so, it must be disclosed and evaluated in a revised DEIR.

While it may be true that the tank modifications may also allow faster ship unloading and decreased emissions, the DEIR cannot simply cloak one particular benefit of this Project component as the very purpose of the modifications. The DEIR would have the public believe that Tesoro is investing in tank modifications that increase storage capacity to twice the size of the entire existing crude storage at Wilmington for the sole purpose of having ships offload faster. CEQA does not allow for such a truncated and misleading analysis. The omission of the foreseeable potential impacts to increased sales or processing of higher throughput, and even a crude switch accommodation, from the tank modifications seriously undermines the purpose of the public participation provisions of CEQA and makes meaningful identification and assessment of the potentially significant environmental impacts of the Project impossible.[49]

G1-86.14 cont'd.

Accordingly, the Project Description must be amended to reflect the storage tank modification's increased throughput and end uses and possible crude switch utility. A revised DEIR must disclose the current crude oil type baseline, and evaluate the vapor pressure, heating coils, other equipment and permit limits for tanks, regarding how they may accommodate a crude oil slate change, and the associated impacts.

f. The Project's proposed new de-sulfurization equipment enables expanded imports of advantaged crude, and is not merely for the purpose of meeting federal low-sulfur fuel standards.

As May's Technical Report explains, the Project proposes to "add a significant amount of sulfur contamination removal equipment as part of the Project[,] contamination [which] comes into the refinery with the crude oil."[50] The DEIR touts that the Project will reduce sulfur contamination, by way of modifications to hydrotreaters and other additions to Refinery equipment, for the purpose of complying with federal tier-three standards. May's examination and other evidence, however, casts doubt on the ostensibly benevolent objective of this Project component, and rather points to a different purpose altogether, which the Project Description fails to disclose.

G1-86.15

The DEIR explains that "hydrotreating units remove sulfur and nitrogen from process streams; sulfur in the form of hydrogen sulfide, and nitrogen in the form of ammonia, which are then converted into elemental sulfur and nitrogen in sulfur recovery units."[51] May's Technical Report explains that extensive sulfur removal equipment already exists at the Wilmington and Carson refineries, and outlines the Project's proposal for new and expanded process units for this same purpose.[52] May concludes that "the large increase in desulfurization equipment appears out of proportion with what is needed to comply with federal Tier 3 standards,"[53] since Tesoro

[48] May Technical Report, § III(E).
[49] *See Sierra Club v. State Bd. of Forestry* (1994) 7 Cal. 4th 1215, 1230 (1994).
[50] May Technical Report, § III(D).
[51] DEIR, at 2-12.
[52] May Technical Report, § III(D).
[53] May Technical Report, § III(D).

already complies with California's low-sulfur fuel standards, and out-of-state sales that require Tier III compliance comprise a small fraction of Tesoro sales,

Accordingly, the Project's increased hydrotreating cannot be solely for compliance.[54] Tesoro admits as much. After explaining that "the majority of the gasoline has [already] been 10 ppm in California for some time[,]" Tesoro's Chairperson and CEO stated that the Project "does allow [it to] get to the full compliance with tier-three gasoline[,]" but "it is a *small* part of [the Integration Project]."[55]

Accordingly, as explained by May, a need for such increased sulfur removal processing in the refinery can be explained only if Tesoro brings in significantly more high-sulfur crude oil[,]"[56] which, as explained above, it specifically plans to do. For example, Canadian tar sands crude oil typically has very high sulfur levels. Based on the evidence, it appears that the Project's de-sulfurization component allows for the additional processing of sulfur content, potentially from high sulfur crude oil. This objective must be disclosed in the Project Description, since the processing high-sulfur crude may cause refinery processing problems and severe safety hazards.[57] For example, sulfur compounds are corrosive and can attack refinery equipment, which can lead to explosions, such as happened in the Chevron Richmond refinery, which nearly killed 19 workers and sent 15,000 neighbors to the hospital. By failing to disclose the full scope of the de-sulfurization component, the DEIR's Project Description fails to inform the public about the true nature of the activity proposed, and therefore must be rejected.

G1-86.15 cont'd.

In sum, the DEIR fails to disclose a fundamental Project characteristic by omitting that the Project enables Tesoro's intended transition to process discounted, advantaged crudes at the Refinery. The DEIR's statements concluding that the Project will not impact the types of crudes used at the refinery are defied by the overwhelming evidence found in oil industry literature, investor reports, expert reports, and permitting documents, as discussed above and in May's Technical Report. That evidence shows that the Project will enable Tesoro to process advantaged crudes, including Bakken crude oil and tar sands, at the Refinery. The Project describes precisely the kinds of physical changes and operational shifts required to effect a shift in the types of crudes stored, delivered, processed, and refined there.[58] Omission of the changes in crude slate prevents the public from ascertaining the nature and general magnitude of environmental impacts.[59] The Project Description's use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency has not proceeded in a manner required by law.

G1-86.16

Because the DEIR relies on an inadequate project description, its examination of significant impacts associated with modifications that will allow the Refinery to process heavier crude is also untenable. The SCAQMD may not proceed with the Project approval based on the

[54] May Technical Report, § III(E).
[55] Edited Transcript TSO - Q1 2016 Tesoro Corp Earnings Call MAY 05, 2016, p. 15 (emphasis added), *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-transcriptsarchive.
[56] May Technical Report, § III(D).
[57] May Technical Report, § III(E).
[58] *Id.*; *see also* Neg. Dec., at 1-1 ("The two new tanks are proposed to be permitted to store light and heavy crude oils of varying vapor pressures up to 11 pounds pre square inch (psi) . . . .")
[59] *See* CEQA Guidelines, §15124 (requirements of an EIR).

DEIR because it omits a significant component concerning crude slate, which has severe environmental and safety impacts. The DEIR's analysis of such significant environmental impacts demands further environmental review to determine what impacts may result from changes in crude quality at the Refinery. The planned crude slate modification is an integral part of the integration Project, and must be evaluated in the DEIR.

Moreover, the failure to disclose the type and chemical composition of the new crude oils and their resultant potential impacts is a "threshold issue" and "fundamental defect" in environmental review that violates CEQA.[60] Consequently, it is simply impossible for the DEIR to provide any accurate estimation of impacts. At a minimum, the DEIR should establish how the Project will affect the scope and degree of the Refinery's use of Bakken and tar sands crude and evaluate resulting impacts.[61] Until such adequate disclosure occurs, the Project Description is inaccurate, incomplete and renders the analysis of significant environmental impacts inherently unreliable.[62]

G1-86.16 cont'd.

2. The Project Description is deficient because it fails to properly identify the size and capacity of the refinery.

The Project Description is further inadequate because it presents contradictory information relating to the total crude oil capacity of the refinery. The refinery's size and capacity are basic and fundamental characteristics, and the contradictory information renders the Project Description and analysis of its significant impacts inadequate under CEQA.

An EIR is inadequate and misleading if its Project Description contains information that considerably differs from data reported under oath in an SEC Annual Report.[63] According to the Project Description, "[t]he total crude oil rate capacity for the Los Angeles Refinery is 363,000 bbl/day."[64] Tesoro's 2015 Annual Report, however, indicates that the Los Angeles Refinery's total crude oil capacity is 380,000 bbl/day.[65] The crude oil capacity discrepancy between that reported in the DEIR and Tesoro's SEC representations amounts to a considerable difference of 17,000 bbl/day, which has vast implications for the environment and community health and safety.

G1-86.17

The DEIR's failure to account for the 17,000 bbl/day difference in crude oil capacity renders the Project Description inadequate for several reasons. The Project Description states that the refinery's crude oil capacity will increase by 6,000 bbl/day, or two percent, as a result of the Project.[66] Based on the inconsistent and scant data, it is left unknown whether this increase is

[60] *See Richmond*, 184 Cal. App. 4th 70.
[61] *Id.*
[62] *San Joaquin Raptor/Wildlife Rescue Center*, 27 Cal.App.4th at 722 (the failure to include relevant information relating to a project's components precludes informed decision making, thwarting the goals of the EIR).
[63] *See Richmond*, 184 Cal.App. 4th at 83-84.
[64] DEIR, at 2-17.
[65] Tesoro Corporation, Annual Report, 5 (Form 10-K) (Feb. 25, 2016); *see also Los Angeles Refinery Fact Sheet*, Tesoro, https://tsocorpsite.files.wordpress.com/2016/04/tesoro-los-angeles-fact-sheet.pdf.
[66] DEIR, at 2-2.

on top of the 17,000 bbl/day increase reflected by Tesoro's 2015 Annual Report. If so, the Project Description fails to disclose a total crude oil capacity increase of 23,000 bbl/day – ***three times*** the amount identified in the DEIR as the crude oil capacity increase.

The unstated 17,000 bbl/day by itself represents a major increase of five percent in crude oil capacity. Oil refinery capacity is generally described in terms of the amount of crude oil processed in distillation units at the refinery's front-end. The refinery takes crude oil inputs, and separates its components in the distillation units. These components then undergo additional processing in cracking and coker units. Portions are alkylated, reformed, blended, and in the case of high-sulfur portions, hydrotreated. The DEIR does not identify the nature of the inputs–crude oil or other intermediate products–that compose the additional 17,000 bbl/day. Thus, it is impossible to determine which processes the inputs will have to undergo, and, more importantly, the environmental impacts resulting from such capacity increase.

G1-86.17 cont'd.

The DEIR's failure to properly identify the true size and nature of the refinery not only renders the Project Description inadequate under CEQA, but also raises grave concerns as to the Project's significant and cumulative impacts. Because the DEIR contains unstable and shifting descriptions of the project, public participation is stultified.[67] "By giving such conflicting signals to decision makers and the public about the nature and scope of the activity being proposed, the Project description is fundamentally inadequate and misleading."[68] The DEIR therefore cannot proceed until the basic facts of refinery size are identified.

3. The Project Description is deficient because it fails to disclose the underlying reason for the FCCU shutdown.

The Project Description is inadequate because it fails to disclose the full scope of the Project's nature and objectives, such as compliance with preexisting binding commitments arising out of the government's approval of the Wilmington/Carson facility merger. The DEIR characterizes the Project, in part, as a pollution-reducing initiative that will allow for the retiring of the dirty, outdated, Wilmington FCCU. The stated purpose of the FCCU is pretextual, however, and the DEIR must be revised to disclose an accurate purpose for the FCCU shutdown.

G1-86.18

On May 17, 2014, the California Attorney General's office announced its approval of Tesoro's acquisition of BP's Carson refinery. This approval came as a result of a nine-month investigation in which the Attorney General's office, along with other State and Federal agencies, reviewed the possible impacts of the merger. Two of the chief barriers impeding the merger were antitrust concerns, and the potential environmental impacts that the merger could cause.[69] In order to address these concerns, Tesoro entered into a "binding commitment" to shut

[67] *San Joaquin Raptor Rescue Ctr v. County of Merced*, 149 Cal.App. 4th 645, 674 (Cal.App. 2007) (*citing County of Inyo v. City of Los Angeles*, 71 Cal.App.3d 185, 192 (Cal.App. 1977)).
[68] *Richmond*, 184 Cal.App. 4th at 84 (citing *San Joaquin Raptor Rescue Ctr*, 149 Cal.App. 4th at 655-656).
[69] AG Letter to Tesoro, CA DOJ, *available at* http://oag.ca.gov/system/files/attachments/press_releases/AG%20Letter%20to%20CEC%20%28Tesoro%29.pdf?.

down the Wilmington and Carson FCCUs, and replace them with a single DDU.[70] The Attorney General approved the merger subject to this condition. Hence, the shutdown of the Wilmington FCCU has a threshold purpose–compliance with the terms of the merger approval.

The Project Description dedicates a section to reciting the Attorney General's approval letter, yet it curiously omits mention on the requirements on which the merger approval was conditioned.[71] Instead, the DEIR describes Project's purpose as "more fully integrat[ing]" the Carson and Wilmington Operations, increasing efficiency through "process modifications that [will] enable shutting down the [Wilmington FCCU]."[72] Such a description of the Project is not only inadequate, but is vastly deceptive.

The DEIR's willful omission of Tesoro's "binding commitment" to shut down the FCCU obscures the Project's purposes, and renders the DEIR inadequate under CEQA.

G1-86.18 cont'd.

4. The Project Description is also deficient because it fails to disclose the full extent and nature of the Project's unprecedented tanks expansion.

The Project Description describes the construction of six new tanks at the Carson Crude Terminal with 500,000 bbls capacity, and replacing two existing 80,000 bbls crude oil tanks at the Wilmington Operations with two new 300,000 bbls tanks. According to the DEIR, the Project's massive tank expansion will "[i]mprov[e] efficiency of water-borne crude oil receipt and marine vessel unloading[,]" and "will reduce vessel emissions at the Port of Long Beach."[73] The DEIR claims that "[t]he tanks only affect the ability to offload a marine vessel in less time."[74] Evidence suggests otherwise, however. May's technical analysis points to a discrepancy between the DEIR's narrow conclusion concerning the purpose of the tank expansion Project component, and the significant increase in new throughput capability enabled by the expansion. Evidence indicates that the tank expansion will not only enable importing of large volumes of "advantaged crudes," but allow large scale exports, information which has been improperly withheld from the DEIR.

As examined in the May Technical Report, the Project tank expansion is extraordinary, adding not only 3.4 million barrels' volume of crude oil storage, but also increasing throughput by almost 420,000 barrels/day.[75] The Report explains that, "[b]y comparison, the existing Tesoro LA refinery complex can process crude oil of at least 363,000 bbls/day, and in addition already has storage to accommodate its current daily crude throughput needs, so the new tanks would add new throughput capability greater than the entire existing refinery currently processes."[76]

G1-86.19

[70] *Id.* at 2.
[71] DEIR, at 2-1.
[72] DEIR, at 2-1, 2-2.
[73] DEIR, at 2-39.
[74] DEIR, at 2-39.
[75] May Technical Report, § III(E).
[76] May Technical Report, § III(E).

Further, the new tanks "would accommodate the entire daily shipment from the Tesoro Savage terminal[,]"[77] meaning that the tank expansion will enable import of advantaged crude.

Moreover, "[s]ince the Tesoro Savage Vancouver facility is slated at 360,000 bpd . . ., the increased throughput permitted for the new tanks at about 420,000 bpd Tesoro could sell the excess crude to other LA refineries, or export it[.]"[78] This suggests that "[t]he Tesoro Project could open up *all* the Los Angeles refineries to these crude oils, and could become Tesoro's export terminal."[79] Tesoro's own evidence shows that it has stated plans to open up its South Coast assets to third party transfers.[80] For example, the Refinery could sell Bakken or Canadian crude oil to other Los Angeles refineries, and even open up *all* the Los Angeles refineries to these crude oils, thus becoming Tesoro's export hub.[81] Accordingly, the tank expansion has a much broader function and purpose than the innocuous one disclosed by the DEIR. G1-86.20

The Project Description must disclose the import and export capabilities allowed by the tank expansion, so that the significant impacts of such functions can be examined. Unless and until it does so, the DEIR will remain fundamentally flawed.

IV. THE PROJECT IS PIECEMEALED.

A. The DEIR must include environmental review of the Vancouver Energy Terminal ("Tesoro Savage Terminal") Project.

The DEIR employs "piecemeal" environmental review by failing to consider the combined effects of the proposed Tesoro Savage Terminal Project with the Los Angeles Refinery ("LARIC") Project. Specifically, the DEIR excludes any environmental impact analysis for the VET in its assessment of the LARIC even though the two projects are interdependent. CEQA prohibits this type of piecemealed review, requiring that an EIR describe the entirety of a project, including any reasonably foreseeable future actions that are part of it.[82] Illegally "chopping a large project into many little ones" creates a narrow view of a project and a "fallacy of division . . . that is, overlooking a project's cumulative impact by separately focusing on isolated parts of the whole."[83] Certainly, any permit-by-permit review, where those permits constitute a larger project, forecloses this essential focus on cumulative impacts, and also, impacts to already overburdened and vulnerable populations. G1-86.21

In *Laurel Heights I*, the Supreme Court established the minimal treatment for piecemealing: while an EIR need not include speculation about future environmental consequences of a project,

[77] May Technical Report, § III(F).
[78] May Technical Report, § III(F).
[79] May Technical Report, § III(F).
[80] May Technical Report, § III(F).
[81] May Technical Report, § III(F).
[82] CEQA Guidelines, § 15378(a).
[2] *See Bozung v. Local Agency Formation Commission* (1975) 13 Cal.3d 263, 283-84.

> "the EIR must include an analysis of the environmental effects of future expansion or other action if: (1) it is a reasonably foreseeable consequence of the initial project; and (2) the future expansion or action will be significant in that it will likely change the scope or nature of the initial project or its environmental effect."[84]

Under this standard, "the facts of each case will determine whether and to what extent an EIR must analyze future expansion or other action."[85] A project proponent must analyze future expansion and other such action in an EIR if there is "telling evidence" that the agency has either made decisions or formulated reasonably definite proposals as to such future activities.[86] Further, there must be discussion "in at least general terms" of the future activity, even if the project is contingent on uncertain occurrences.[87]

SCAQMD's piecemealed environmental review of the VET and LARIC Projects is supported by the facts of *Laurel Heights I* and *San Joaquin Raptor*.[88] In *Laurel Heights I*, the Supreme Court set aside an EIR for piecemealing the second phase of a multi-phased project. In that case, the University of California, San Francisco ("UCSF") proposed a project to expand into a new building, of which only about one-third was initially available.[89] Because UCSF's EIR failed to analyze the impacts of the project related to the remaining two-thirds of the building when its use was wholly foreseeable at the project's inception, the Court rejected the EIR.[90] In *San Joaquin Raptor*, the court similarly rejected an EIR for a development project because it failed to discuss the impacts associated with a sewer system expansion, even though the project's developer recognized the "necessity" of the sewer expansion for the overall project to proceed.[91]

G1-86.21 cont'd.

In contrast, in *Richmond* and *Berkeley Jets*, the courts found that the EIRs under examination were not piecemealed, despite their exclusions of related projects.[92] In *Richmond*, the court of appeal found that an EIR for a refinery expansion project which did not fully analyze the potentially significant cumulative impact of a hydrogen pipeline project was not piecemealed, and found it to be separate from the overall expansion project.[93] The court reasoned that the expansion and pipeline projects were independent, performing entirely different functions.[94] The court focused on the stated project objectives in making its decision: while the

[84] *Laurel Heights Improvement Association v. Regents of University of California* (1988) 47 Cal.3d 376, 395-96 (*Laurel Heights I*).
[85] *Id.* at 396.
[86] *Id.* at 397.
[87] *Id.* at 398.
[88] *See Laurel Heights I*, 47 Cal.3d 376*; see also San Joaquin Raptor*, 27 Cal.App.4th at 734.
[89] *Laurel Heights I*, 47 Cal.3d at 393.
[90] *Id.* at 397.
[91] *See San Joaquin Raptor*, 27 Cal.App.4th at 734.
[92] *See Richmond*, 184 Cal.App.4th 70; *see also Berkeley Keep Jets Over the Bay Comm. et. al. v. Board of Port Cmrs.* (2010) 91 Cal.App.4th 1344, 1361 (*Berkeley Jets*).
[93] *See Richmond*, 184 Cal.App.4th at 97.
[94] *Id.* at 101.

expansion project's objective was to access a wider range of crude oil and other feedstocks, the pipeline project's objective was to transport excess hydrogen to other hydrogen consumers in the Bay Area.[95] The court ultimately found that because the expansion project did not "depend on" the pipeline project, the project was not piecemealed.[96] Similarly, the court in *Berkeley Jets* rejected an argument that an airport development plan should have included long-range plans for potential runway expansions because these future expansion plans were neither crucial elements nor foreseeable consequences of the development plan.[97]

As in *Laurel Heights I* and *San Joaquin Raptor*, where both EIRs were rejected because of their respective failures to analyze impacts of foreseeable or necessary aspects of their projects, the LARIC Project DEIR should be rejected because the VET is both a foreseeable and necessary component for the LARIC's success. One of the LARIC's most notable objectives is to "[i]mprove [the] efficiency of water-borne crude oil receipt and marine vessel unloading . . . by constructing six new 500,000 barrel tanks at the Carson Crude Terminal and replacing two existing 80,000 barrel crude oil tanks at the Wilmington Operations with two 300,000 barrel tanks."[98] In other words, it aims to add about 3.4 million barrels of crude oil storage, and allows about 420,000 BPD of increased throughput.[99] With its current feedstocks dwindling, it is foreseeable, if not certain, that this increase in storage and processing capacity will depend upon shipments from the Tesoro Savage Terminal.

G1-86.21 cont'd.

As proposed, the Tesoro Savage Terminal Project entails the creation of a crude-by-rail to oil tanker terminal at the Port of Vancouver, Washington, which would "receive an average of 360,000 barrels of crude oil per day by rail . . . then load the oil onto marine vessels for transport" to allow increased importation of cost-advantaged North American crudes to various West Coast refineries.[100] The Tesoro Savage Terminal Project's DEIS notes that it is intended to serve the growing demand of West Coast refineries for mid-continent crude oil amidst the declining availability of the more expensive Californian and Alaskan oils that have historically been used by the LARIC.[101]

The Tesoro Savage Terminal Project's goal is consistent with Tesoro's statements to its investors, which laud the Tesoro Savage Terminal as an integral part of its plan to bring cost-advantaged crudes to its West Coast refineries.[102] While these crudes are more affordable, however, they come at a price: primarily from North Dakota, Montana, and Canada, these crudes are of lower quality than the crudes the LARIC currently processes, and thus, may result in

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[95] *Id.*
[96] *Id.*
[97] *See Berkeley Jets*, 91 Cal.App.4th at 1362.
[98] DEIR, at 1-6, 1-7
[99] May Technical Report, § III(E).
[100] Tesoro Savage DEIS, Executive Summary (ES-2), *available at* http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20Chapters/DEIS%20Ch%200b%20Exec_Summary.pdf.
[101] DEIR, McGovern Report at F-14.
[102] Tesoro Presentations webpage: Morgan Stanley Corporate Access Day, 5/12/16, Slideshow entitled: *Driven to Create Value, Morgan Stanley Refining Corporate Access Day, May 2016*, Slides 13 & 15, *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.

significant environmental impacts that necessitate assessment.[103] Without increased supply from the Tesoro Savage Terminal of affordable alternative crudes, it is not likely that the LARIC would attempt to expand its capacity or update its equipment to process dirtier crude – however, it is, and has been, doing just that.[104]

Thus, in contrast to the holdings in *Richmond* and *Berkeley Jets*, where the respective EIRs were not found to be piecemealed, here, the Tesoro Savage Terminal is a crucial functional element of the LARIC Project. The LARIC's dependence upon the Tesoro Savage Terminal is even admitted in its investor reports, which state that its purpose is to remain competitive by increasing its processing of cost-advantaged crudes from the North American mid-continent through use of the Tesoro Savage Terminal.[105] The May Technical Report also includes many other places where the LARIC relies on the Tesoro Savage Terminal.[106]

In order for Tesoro to implement its "advantaged crude" strategy at the LARIC, approval of the Tesoro Savage Terminal Project is necessary, because the Tesoro Savage Terminal Project enables the importation of fracked Bakken oils and heavy Canadian tar sands. The LARIC's profitability, success, and overall objectives hinge on the reliable and abundant supply of crude oil that will come from the Tesoro Savage Terminal. These projects are interrelated, wholly anticipate each other in order to achieve the company's "advantaged crude" objective, and together create significant impacts on the environment. Together, the projects satisfy the two-part *Laurel Heights I* test, and are far removed from court decisions in *Richmond* and *Berkeley Jets* that did not find piecemealed projects on account of insufficient showings of "necessity." G1-86.21 cont'd.

The DEIR errs in asserting that it does not need to include an impact analysis for the Tesoro Savage Terminal Project. The Project proponent contends that because the Terminal Savage Project is not approved, it is under independent review by the state of Washington, it will provide crude to other refineries, neither project needs the other to proceed, and the LAR has limited ability to process light Bakken crude, the Terminal Savage Project and LARIC Projects are independent of one another.[107] This reasoning is incorrect.[108]

First, courts have determined, for example, that "when a particular type of retail business planned for a proposed project will have unique or additional impacts, then disclosure of the type of business is necessary in order to accurately recognize and analyze the environmental effects

[103] May Technical Report, § II(D).
[104] May Technical Report, §§ III(D-E).
[105] May Technical Report, §§ II(B).
[106] May Technical Report, §§ II(C).
[107] DEIR, at 4-5.
[108] *But compare Citizens for East Shore Parks v. California State Lands Commission* (2011) 202 Cal.App.4th 549 (The court upheld the certification of an EIR for a Chevron marine terminal, even though the EIR considered only the effects of the marine terminal while excluding the effects of the adjacent Chevron refinery) (*Citizens for East Shore Parks*).

that will result from the proposed project."[109] Here, it is clear that rail and marine vessel transport of Bakken crude and Canadian tar sands will pose "unique or additional adverse effects" that reach beyond the effects of shipping other types of crudes, including heightened risks of combustion, corrosion, and environmental degradation.[110] Second, under CEQA, a single project is allowed to undergo separate agency approvals while still maintaining its status as a single project.[111] Thus, it should not matter that the Tesoro Savage Terminal Project will undergo independent approval by the state of Washington.

In an outlier case, *Citizens for East Shore Parks,* the court cited no authority to support its holding, and instead based its decision on an unfounded interpretation that the scope of CEQA review is limited to the parts of a project subject to lead agency approval. This case does not override or negate the clear relationship of the Project to the Tesoro Savage Terminal Project. Local supplies of crude oils are declining. How, and why, would the LARIC Project even occur were it not inextricably linked with a plan to increase supplies to the area? Those supplies must come from a source, and with the Project's marine receipt expansion, those supplies will come from the Tesoro Savage Terminal.[112] The need for the Tesoro Savage Terminal Project was, therefore, wholly foreseeable at the inception of this Project and necessary for the LAR's objectives.[113] Because the Tesoro Savage Terminal and LARIC Projects together implicate greater and significant environmental impacts from transporting and refining lower quality oil feedstocks at the LAR, the two projects are piecemealed, and thus, the DEIR is unacceptable under CEQA guidelines.

G1-86.21 cont'd.

B. The DEIR should also include environmental review of other interrelated projects.

In addition to analyzing the environmental impacts associated with the VET Project, the DEIR must also evaluate the environmental impacts associated with the following interrelated projects in order to provide an accurate environmental impact analysis:

- Los Angeles International Airport ("LAX") Pipeline and Storage Tanks: Despite Tesoro Logistics' 2015 purchase of "crude oil and refined product storage and [a sixteen mile] pipeline . . . from Tesoro, which includes "97 . . . storage tanks . . . with a capacity of 6.6

G1-86.22

[109] *See Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1213 (*Bakersfield*) (Due to the unique effects of 24-hour supercenters on urban development, the EIR was required to disclose information about its expected retail tenants); *see also American Canyon Community United for Responsible Growth v. City of American Canyon* (2006) 145 Cal.App.4th 1062, 1075 (same scenario as in *Bakersfield*).
[110] May Technical Report, § IV(A)(3).
[111] *See Orinda Association v. Board of Supervisors,* 182 Cal. App. 3d 1145, 1172 (1986) (The construction of new buildings and the demolition of older buildings were all part of the same development project, despite separate agency approvals); *see also* Cal. Code Regs., tit. 14, §15378(c).
[112] May Technical Report, § II(C).
[113] *See* Issuance of DEIS for Vancouver Energy Project in November 24, 2015, *available at* http://www.efsec.wa.gov/Tesoro%20Savage/SEPA%20-%20DEIS/DEIS%20Chapters/20151124DEIS_CvtLtr.pdf.

million barrels" to store and provide fuels for LAX,[114] the DEIR fails to investigate the impacts that the LAR Project may have on the LAX Project. These impacts must be evaluated.

- Expansion of the Pipeline at the Marine Terminal to the Storage Tanks: The DEIR fails to analyze the impacts related to its plan to expand its pipeline at the marine terminal from 12 to 42 inches, as was proposed in its 2014 Neg. Dec.[115]

- Tesoro Logistics Operations: The DEIR must also evaluate the cumulative impacts associated with other Tesoro Logistics operations, since Tesoro has identified future plans of synergism between the LARIC and Tesoro Logistics. In the past, Tesoro has sold many of its facilities to Tesoro Logistics for "gathering, moving, storing, and distributing petroleum inputs and products."[116] The environmental impacts associated with any modifications that the LARIC Project will impose on the relationship between the two businesses must be evaluated.

- Offsite Hydrogen Baseline Sales and Sales of Hydrogen: The DEIR should include an evaluation of the baseline of hydrogen purchased from offsite companies and changes in sales of hydrogen from offsite companies, such as Air Products, to establish whether the Project will increase overall hydrogen use at the refinery.[117]

- San Pedro's Butane Storage Tanks: Because the LARIC Project will require more LPG to be transported by rail, the DEIR must address the environmental impacts associated with San Pedro's butane storage tanks, including details about the parties using the San Pedro products, the volume of the products transported, the methods of transportation, and explosion risks. While Tesoro asserts that it does not store butane at the San Pedro site, it has noted that it sells LPG products to third parties in the area.[118] The impacts of these sales must also be assessed.

G1-86.22 cont'd.

By failing to analyze these projects in relation to this project, the DEIR has piecemealed the Project in violation of CEQA.

V. THE DEIR FAILS TO ANALYZE A REASONABLE RANGE OF PROJECT ALTERNATIVES.

The DEIR fails to consider a reasonable range of alternatives. It distorts the "No Project" alternative and fails to consider alternatives that would meet project objectives while mitigating adverse environmental impacts. CEQA includes a substantive mandate that public agencies not

G1-86.23

[114] May Technical Report, § VI(2).
[115] May Technical Report, § V(C).
[116] May Technical Report, § VI(2).
[117] May Technical Report, § VI(2).
[118] May Technical Report, § VI(2).

approve projects with significant environmental effects if "there are feasible alternatives or mitigation measures" that can substantially lessen or avoid those effects.[119]

G1-86.23 cont'd.

The DEIR does not consider an alternative that makes only the changes necessary to achieve the "synergies [that] will benefit the environment by lowering greenhouse gases and emissions" as required by the settlement agreement with the Attorney General.[120] For example, significantly increasing tank throughput is not necessary to gain the benefits of more efficient marine vessel unloading.[121] Nonetheless, the DEIR project description includes an increase of 25.5 million bbl/year throughput in new tanks.[122]

G1-86.24

Moreover, the DEIR does not include a crucial alternative that limits changes to the refinery's crude slate because DEIR project description fails to consider likely changes to the crude slate.[123] This has resulted in an "impermissibly truncated project description" causing a "severely distorted" range of alternatives.[124] Currently the DEIR claims no changes to the "crude operating envelope," however Canadian tar sands and fracked Bakken crude can be mixed to achieve a similar "operating envelope."[125] This will cause increased emissions of methane, benzene and toxics,[126] which can undo the emissions gains required by the settlement agreement. Limiting changes to the current baseline will address the true environmental impact caused by the likely switch to Canadian tar sands and fracked Bakken crude.

An alternative that includes explicit limitations to deviations from current crude baselines is feasible. In fact, the DEIR states that the modifications to the plants' operations will not affect the types of crude oil processed.[127] While this is misleading and modifications will allow changes to overall crude quality,[128] an alternative that explicitly limits deviations from current crude slate baselines does not interfere with the project's stated objectives.

G1-86.25

Furthermore, the adverse impacts of the "No Project" alternative are distorted. The DEIR states that the "No Project" alternative "could be infeasible" because the refinery would be in violation of future federal Tier 3 gasoline requirements and local and state emissions requirements.[129] However, this implies that the proposed project is the only means of complying with these requirements, but the DEIR never states whether or not this is the case. CEQA guidelines do not always equate disapproval of a project with no development whatsoever. Instead, the EIR should "project[] what would reasonably be expected to occur in the foreseeable

G1-86.26

[119] *Mountain Lion Foundation v. Fish and Game Commission* (1997) 16 Cal. 4th 105, 134.
[120] Letter from Kamala Harris, Attorney General, to Robert Weisenmiller, CEC Chair, https://oag.ca.gov/system/files/attachments/press_releases/AG%20Letter%20to%20CEC%20(Tesoro).pdf (May 17, 2013).
[121] May Technical Report, § III(E).
[122] May Technical Report, § III(E).
[123] May Technical Report, § III(C).
[124] *See County of Inyo v. City of Los Angeles* (1981) 124 Cal. App. 3d 1, 9.
[125] DEIR, at 4-2.
[126] May Technical Report, § IV.
[127] DEIR, at 4-2.
[128] Fox Neg. Dec. Report, at 12-13.
[129] DEIR, at 6-5.

future if the project were not approved."[130] Here, a reasonable expectation would be that Tesoro will make only the modifications needed to comply with federal, state and local emissions requirements. Including and describing this foreseeable outcome will inform decision-makers by outlining which components are actually needed to comply with emissions requirements. G1-86.26 cont'd.

While an EIR is not expected to identify every single possible alternative to a proposed project, it is unacceptable for an EIR to fail to describe an alternative that accomplishes the goals of complying with the mandates imposed by law and by the Attorney General, and then distort the environmental impacts of the No Project Alternative. By failing to adequately describe the "No Project" alternative and failing to analyze an alternative that implements legal requirements without imposing the Project's impacts, the DEIR's analysis of project alternatives fails to meet CEQA's requirements because it does not include the alternatives necessary for decision-makers to make a "reasoned choice."[131] G1-86.27

VI. THE DEIR FAILS TO IDENTIFY A LEGALLY SUFFICIENT BASELINE.

The DEIR employs a misleading and wholly inaccurate baseline to measure air quality and other impacts. "The fundamental goal of an EIR is to inform decision makers and the public of any significant adverse effects a project is likely to have on the physical environment."[132] Such effects cannot be known without first "delineat[ing] environmental conditions prevailing absent the project, defining a 'baseline' against which predicted effects can be described and quantified."[133] "[B]aseline determination is [therefore] the first . . . step in the environmental review process[,]"[134] and critical to the entirety of an EIR. A baseline must "give the public and decision makers the most accurate picture practically possible of the project's likely impacts"[135] An inaccurate baseline can drastically alter the outcome of environmental review—if baseline emissions are set too low, insignificant impacts become significant, and if baseline emissions are set too high, an EIR can overlook significant impacts on the environment. G1-86.28

Here, the DEIR both improperly underestimates the baseline for certain conditions, and inflates the baseline for others.

A. The DEIR Fails to Identify Required Baselines for Crude Throughput.

It cannot be disputed that the volume of crude throughput determines environmental impacts, yet, the DEIR's baseline for throughput is entirely unclear. The DEIR fails to disclose a certain throughput baseline, and appears to rely instead on fluctuations in operations, maximum capacities, and permitted levels of various operation components in discussing throughput. G1-86.29

[130] CEQA Guidelines, §15126.6(e)(2)
[131] CEQA Guidelines, §15126.6(f)
[132] *Neighbors for Smart Rail v. Exposition Metro Line Const. Authority* (2013) 57 Cal.4th 439, 447.
[133] *Id.*
[134] *Save our Peninsula Committee v. Monterey County Board of Supervisors* (2001) 87 Cal.App.4th 99, 125.
[135] *Neighbors for Smart Rail*, 57 Cal.4th at 449 (citing *Communities for a Better Environment v. SCAQMD* (2010) 48 Cal.4th 310).

Further, evidence regarding the total crude oil rate capacity and Refinery throughput is unclear and inconsistent, leaving the public without reliable information as to the existing throughput baseline. For example, the DEIR states that the "total crude oil rate capacity for the Los Angeles Refinery is 363,000 bbl/day[,]"[136] while Tesoro has publicly reported that its full capacity is 380,000 barrels per day.[137] Not only does the DEIR fail to establish an ascertainable baseline for overall refinery throughput, but the information provided as to Refinery throughput is not supported by data. Conclusions and baselines reflected in environmental documents must be based on actual data, and that data must be publicly accessible. The DEIR fails these requirements. May's technical analysis of the Refinery throughput raises whether the Refinery could be processing larger volumes than the DEIR has evaluated, including whether it already increased its throughput, even before receiving approval.[138] G1-86.30

The DEIR also fails to establish a baseline for storage tank throughput, although the record and evidence shows its significant increase. May explains that the six largest new tanks "increase [] throughput . . . [by more] than 153 million bbl/year (or 419,000 bbls/day average)," increasing volume by 3.4 million bbls. The DEIR provides only the volume capacity for the Wilmington tanks, but not for the Carson facility. Moreover, the SCAQMD questioned whether a No. 51 Vacuum Distillation Unit heater may result in increased crude oil throughput, but the DEIR fails to evaluate the issue.[139] The DEIR states that "[t]here is no change proposed to crude oil throughput at the Carson Operations" and "no changes to the Crude Units are being made that would affect the crude oil throughput of the Wilmington Operations."[140] As May explains, however, "[t]his conclusory statement fails to account for the large permitted throughput increases that were modeled in the DEIR[.]"[141] The increased tank throughput will result in undisclosed impacts, whether as a result of that throughput being exported or refined. If the latter, the overall Refinery input will further increase. G1-86.31

Because evidence shows that the Project will result in an increased throughput, at the very least as to storage tank and overall refinery throughput, the DEIR must identify the pre-Project throughputs and establish baselines against which the increased throughputs can be examined to determine any significant impacts from the increase. G1-86.32

B. The DEIR Fails to Identify Critical Baseline Information Relating to the Refinery's Current Crude Slate.

Substantial evidence, as discussed above, shows that the Project proposes to make numerous process and equipment modifications that newly enable the processing of "advantaged crude" feedstock at the Refinery, consistent with Tesoro's publicly stated business plans. It is well-known that the type of crude oil feedstock processed at a refinery directly affects the G1-86.33

[136] DEIR, at 2-17.
[137] May Technical Report, § II(A) (quoting Los Angeles Refinery Fact Sheet 2016, Tesoro, https://tsocorpsite.files.wordpress.com/2016/04/tesoro-los-angeles-fact-sheet.pdf (emphasis added)).
[138] May Technical Report, § II(A).
[139] May Technical Report, § V(B)(1).
[140] DEIR, at 4-26 and 4-28.
[141] May Technical Report, § III(E).

amount and composition of resulting emissions and other environmental impacts.[142] Because the Project's change in crude slate is likely to result in significant impacts, the DEIR must establish a crude slate baseline against which impacts can be measured.

G1-86.33 cont'd.

The court in *Richmond* established that an "EIR fails as an informational document [where] the [] project description is inconsistent and obscure as to whether the Project enables the Refinery to process heavier crude[.]"[143] The DEIR must "properly establish, analyze, and consider an environmental baseline" of crude slate.[144] Here, however, the DEIR never discloses the characteristics of the current baseline oil feedstock at the Carson and Wilmington facilities, and much less compares pre- and post-Project crude quality. As in *Richmond*, the failure to do so is fatal to the DEIR.

As detailed in the May Technical Report, the DEIR fails to disclose exact specifications of the change in crude quality, information that is integral to this project.[145] Although the DEIR insists on its maintenance of throughput limits, it fails to properly acknowledge the inevitable changes in air emissions, hazard risks, and other significant impacts from refining a lower quality oil feedstock. As May explains:

> [E]ven if [the new advantage crude slate is blended to] match[] ANS exactly in API gravity, the switch would still introduce new impacts not evaluated in the DEIR, due to other crude oil characteristics. For example, explosion hazards would increase from Bakken crude introduction, additional content of toxics such as benzene that was not investigated in the DEIR discussion, and increased introduction of waxy residue which can cause processing difficulties requiring more maintenance. Further, increased sulfur mass from Canadian crudes would increase corrosion hazardous and increase acutely hazardous sulfur gases (for example hydrogen sulfide).[146]

G1-86.34

In short, Refinery modifications that enable processing of Bakken and potentially Canadian crudes have major impacts that must be analyzed, unless permit conditions explicitly preclude use of these crudes.

Instead of determining the required crude slate baseline, the DEIR impermissibly provides general information regarding the full range of possible crude that could be used at the Refinery, including outliers.[147] While, as the May Technical Report explains, some of this information can be obtained through research,[148] "decision makers and general public should not be forced to . . . ferret out the fundamental baseline assumptions that are being used for purposes

G1-86.35

[142] May Technical Report, § III(A).
[143] *Richmond*, 184 Cal.App.4th at 89.
[144] *Id.*
[145] May Technical Report, § III(B).
[146] May Technical Report, § III(C).
[147] May Technical Report, § II(D); *see, e.g.*, DEIR, at 2-2.
[148] May Technical Report, § III(B).

of the environmental analysis[.]"[149] Rather, "'[a]n EIR must include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project.'"[150]

G1-86.35 cont'd.

When crude slate changes are at issue, the DEIR must divulge data as to crude slate currently processed at the Refinery, otherwise, a "conclusion that the future crude slate would be 'similar to that which is currently processed' is meaningless."[151] The DEIR must provide "objective quantification of the continuing mix that [the] Refinery was designed to process[,]" and examine whether it "is heavier than [the] mix [the] Refinery is currently processing."[152] As May concludes in her technical report, "[t]his will require documentation of the baselines of the individual Wilmington and Carson crude and intermediate product inputs from before the purchase of BP Carson by Tesoro, to the present."[153]

G1-86.36

Specifically, the DEIR should disclose a "specific baseline for the both the Carson and Wilmington refinery, including the last 5 years' domestic and imported crudes, volumes, geographic origin, transportation method, sulfur content, API gravity, TAN, metal content, other important data such as benzene content, special handling issues due to volatility or waxiness, etc."[154] The DEIR must further evaluate impacts of the planned and foreseeable changes in the crude slate as part of the overall Project.

G1-86.37

Unless and until the DEIR is revised to provide the proper crude slate baseline and examination of crude slate modifications, it will remain deficient as an informational document and also impair a significant impacts analysis.

C. The DEIR Fails to Ascertain the Refinery Sulfur Baseline.

The DEIR also fails to include a baseline for sulfur in the refinery, percent of sulfur in crude oil sulfur and the desulfurization capacity. Such a baseline is necessary because evidence shows that the Project could "introduce a larger mass of sulfur into the refinery compared to the past baseline,"[155] which requires impacts evaluation.

The May Technical Report explains that the Project has the potential to result in "increases in desulfurization processes within the refinery due to higher sulfur content, as well as additional cracking, coking, and additional use of hydrogen, all of which require more energy and increase criteria and toxic pollutant emissions."[156] Further, if "Canadian crude replaces a crude at the Tesoro refinery average shown in the previous estimation of about 1.5% sulfur, the Canadian crude would increase the percent sulfur up to 3.5 or more percent sulfur for that

G1-86.38

[149] *San Joaquin Raptor Rescue Center* 149 Cal.App.4th at 659, as modified (Apr. 11, 2007).
[150] *Id.* (quoting *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 405).
[151] *Richmond*, 184 Cal.App.4th at 85.
[152] *Id.*
[153] May Technical Report, § II(A).
[154] May Technical Report, § III(B).
[155] May Technical Report, § IV(C)(2).
[156] May Technical Report, § IV(B).

number of barrels."[157] "It would also increase the desulfurization processing needed, the processing in the Sulfur Recover Unit, and the energy use and resultant emissions of those processes."[158] Accordingly, "a specific crude oil sulfur baseline is needed, and the potential for that to change, because this impacts the amount of desulfurization downstream."[159]

G1-86.38 cont'd.

The DEIR must provide a refinery sulfur baseline, as outlined by the May Technical Report, in order to inform decision makers and the public of any significant adverse effects the Project will likely to have.

D. Inclusion of FCCU Shutdown Emission Reductions in the Baseline Violates CEQA.

The DEIR's air emissions baseline is flawed because it improperly includes emissions from the Wilmington FCCU,[160] and thereby artificially inflates the baseline. Because the FCCU shutdown was a condition of approval prior to, and independent from, this Project, the baseline should reflect the environmental conditions as they will exist without the FCCU in operation. The pre-Project air quality baseline should therefore remove the FCCU emissions in order to provide the public with an accurate measurement of significant impacts resulting from this Project.[161]

G1-86.39

While CEQA provides that the baseline is *normally* "the physical environmental conditions in the vicinity . . . as they exist at the time the notice of preparation is published[,]"[162] environmental review must depart from the general baseline rule when circumstances require in order to provide an accurate measurement of a project's likely impacts. The State Supreme Court instructed in *Neighbors for Smart Rail* ("*Neighbors*") that a baseline reflecting expected future conditions should be employed if a baseline reflecting current conditions "would be uninformative or misleading to decision makers and the public."[163] A lead agency may therefore define a baseline consisting of expected future environmental conditions if there is substantial evidence showing that it provides "a more accurate picture of a proposed project's likely impacts[.]"[164]

G1-86.40

In *Neighbors*, the SCAQMD argued that the Court should recognize an exception to the existing conditions baseline rule where "factual conditions [exist] in which use of an existing conditions baseline would arguably mask potentially significant project impacts that would be

[157] May Technical Report, § IV(C)(2).
[158] May Technical Report, § IV(C)(2).
[159] May Technical Report, § IV(C)(2).
[160] DEIR, at 4-16.
[161] CEQA Guidelines, § 15125(a).
[162] *Id.*
[163] *Neighbors for Smart Rail v. Exposition Metro Line Const. Authority* (2013) 57 Cal.4th 439, 455.
[164] *Id.* at 453.

revealed by using a future conditions baseline."[165] The Court agreed. The AQMD provided the following example of such factual conditions, which the Court reviewed and concurred with:[166]

> [A]n existing industrial facility currently emits an air pollutant in the amount of 1,000 pounds per day. By the year 2020, if no new project is undertaken at the facility, emissions of the pollutant are projected to fall to 500 pounds per day *due to enforcement of regulations already adopted* and to turnover in the facility's vehicle fleet. The operator proposes to use the facility for a new project that will emit 750 pounds per day of the pollutant upon implementation and through at least 2020. An analysis comparing the project's emissions to existing emissions would conclude the project would reduce pollution and thus have no significant adverse impact, while an analysis using a baseline of *projected year 2020 conditions* would show the project is likely to increase emissions by 250 pounds per day, a (presumably significant) 50 percent increase over baseline conditions.[167]

The factual circumstances concerning the Wilmington refinery FCCU are precisely those where use of an existing conditions baseline would mask potentially significant Project impacts, and therefore where use of a future conditions baseline is necessary to reveal the impacts and fulfill CEQA's mandate.

G1-86.40 cont'd.

The FCCU shutdown is a binding requirement that already existed prior to the Project proposal. The replacement of the Wilmington FCCU was a precondition to the Tesoro-BP acquisition, and thus not a part of the Integration Project. Indeed, government approval of the acquisition was conditioned on the unit's shutdown. Crediting the LARIC Project for the Wilmington FCCU's shutdown creates the type of distortion of baseline measurements that *Neighbors* warned against as "uninformative or misleading to decision makers and the public."

On May 17, 2013, the California Attorney General's office ("AG") announced in a letter to the Chairman of the California Energy Commission ("CEC") the approval of the Tesoro acquisition of BP's Carson operations.[168] This approval came as a result of a nine-month investigation led by the California Department of Justice and other State agencies. During that process, the State identified as primary concerns preventing the approval of the acquisition based on its impact on market competition and the environment.[169] While the AG's competition concerns were addressed after a thorough investigation on market conditions,[170] the acquisition's environmental impact concerns continued to present an obstacle to approval. As identified in the

[165] *Id.* at 453, n.5.
[166] *Id.*
[167] *Id.* (emphasis added).
[168] AG Letter to Tesoro, CA DOJ, *available at* http://oag.ca.gov/system/files/attachments/press_releases/AG%20Letter%20to%20CEC%20%28Tesoro%29.pdf?.
[169] *Id.*
[170] *Id.*

AG's letter to the CEC, the acquisition's approval was conditioned on certain concessions agreed to by Tesoro, including the shutdown of the Wilmington FCCU.[171] Replacement of the FCCU was a "binding commitment" upon Tesoro used to satisfy environmental impact concerns associated with the acquisition.[172] This precondition is also recognized in an April 8, 2013 letter cited by the AG, in which Governor Brown stresses upon Tesoro the importance of shutting down the FCCU units "should the acquisition proceed."[173]

G1-86.40 cont'd.

Further, the DEIR itself shows that the current LARIC Project was not an inevitable component or requirement for the acquisition, but rather a subsequent, voluntary measure Tesoro chose to pursue to "more fully integrate" operations.[174] At the time the acquisition was approved, pipeline connections between the Wilmington and Carson operations already allowed the "transfer of crude oil, feedstocks, and refined products between the two Operations."[175] The requirement to shutdown the Wilmington FCCU became effective at the time of acquisition, and would be required even in the absence of the current Integration Project. To interpret the AG's conditional approval otherwise would render the established preconditions illusory.

G1-86.41

The Supreme Court's holding and illustration in *Neighbors* could not be more analogous to this instance and must be followed here. Because the Wilmington FCCU shutdown is a preexisting requirement, "if no new project is undertaken at the facility, emissions of the [FCCU] pollutant are projected to . . [be eliminated] due to enforcement of [the acquisition shutdown condition]."[176] However, Tesoro now "proposes to use the facility for a new project that will emit" additional pollutants.[177] "An analysis comparing the [P]roject's emissions to existing emissions would conclude the [P]roject would reduce pollution and thus have no significant adverse impact,"[178] which is similar to the outcome reached in the DEIR where the DEIR projected generally less than significant emissions increases. The DEIR in fact relies on the shutdown of the Wilmington FCCU unit in order to obtain a finding of no significant impact. However, "an analysis using a baseline of projected [] conditions would show the project is likely to increase emissions . . . over baseline conditions."[179]

G1-86.42

The DEIR's conclusion that the Project will not cause significant emissions impacts relies on an underlying baseline that incorporates FCCU emissions. Because the shutdown of the FCCU is required to happen even without the Project, and its emissions will be eliminated from environmental impacts, the DEIR's conclusion is misleading and false. The DEIR's inclusion of the FCCU emissions in the air quality baseline artificially and improperly inflates the baseline

[171] *Id.* at 2.
[172] *Id.*
[173] *Id.*
[174] *See* DEIR, at 2-1 (Stating that "[t]he proposed project would greatly *enhance* the integration of overall Refinery operations." This supports the understanding that the Integration Project was not implicitly required for the acquisition to be feasible at the time of the AG's approval, but is rather a subsequent, independent project).
[175] *Id.* at 2-1.
[176] *See Neighbor,* 57 Cal.4th 453, n.5.
[177] *Id.*
[178] *Id.*
[179] *Id.*

emissions, allowing it to overlook significant impacts resulting from the Project. The DEIR's baseline thus fails to include relevant information, precluding informed decisionmaking and denying the public the most accurate picture practically possible of the project's likely impacts. Inclusion of FCCU emissions in the air quality baseline thus thwarts CEQA's statutory goals"[180] and is in grave error.

G1-86.42 cont'd.

For these reasons, the DEIR must be revised to correct the air emissions baseline to reflect the FCCU shutdown and resulting future environmental conditions.

VII. THE DEIR'S IMPACTS ANALYSES ARE SEVERELY FLAWED.

A. Volatile Organic Compound Emissions for Project Operation are Significant.

The DEIR claims that because the Project will purchase emission reduction credits (ERCs) offsetting Project emissions of volatile organic compound emissions (VOCs), operation of the Project will result in less than significant increases of VOCs and therefore no mitigation is required. Because the DEIR estimates this Project will have operational VOC emissions of 401.15 pounds per day (lb/day) —more than 7 times greater than the South Coast air basin's 55 lb/day significance threshold, this Project plainly has significant VOC emissions. SCAQMD must therefore revise the DEIR to find that air emissions will be significant and propose enforceable mitigation measures.

G1-86.43

An EIR must "separately identify and analyze the significance of the impacts [of the project] before proposing mitigation measures."[181] In *Lotus*, Caltrans approved an EIR for a highway construction project through a stand of old growth redwoods. The project would result in tree removal and potential damage to the structural root zones of the trees, but Caltrans determined that this potential damage would not be significant because the project included certain measures designed to reduce or eliminate the damage to the redwoods, including "restorative planting and replanting, invasive plant removal, and use of an arborist and of specialized equipment."[182] The Court of Appeal, in ordering that the EIR be set aside, explained that Caltrans' failure to "separately identify and analyze the significance of the impacts to the root zones of old growth redwood trees before proposing mitigation measures is not merely a harmless procedural failing."[183] Instead, Caltrans was required to first identify "the potential environmental consequences arising from the project" and then thoughtfully analyze "the sufficiency of measures to mitigate those consequences" and adopt an enforceable monitoring program to ensure that the mitigation measures are carried out.[184]

G1-86.44

The DEIR suffers from the same deficiency as in the *Lotus* case. SCAQMD has set a significance threshold of 55 lb/day of VOC operational emissions.[185] Thus, any project emitting

[180] *Kings County Farm Bureau v. City of Hanford*, 221 Cal.App.3d 692, 714 (Cal. Ct. App., 1990).
[181] *Lotus v. Dept. of Transportation* (2014) 223 Cal.App.4th 645, 658 (hereafter *Lotus*).
[182] *Lotus*, 223 Cal.App.4th at 656, n.8.
[183] *Id.* at 658.
[184] *Id.*
[185] DEIR 4-8, Table 4.2-1 ["Mass Daily Thresholds"].

over 55 lb/day has significant emissions that must be mitigated under CEQA.[186] This DEIR has stated operational emissions of 401.15 lb/day.[187] Its VOC emissions are therefore significant under CEQA.

The EIR, however, erroneously concludes that VOC emissions are not significant because the Project will offset these emissions by retiring emission reduction credits.[188] Emission reduction credits are created when a facility voluntarily reduces its air emissions in excess of reductions required by law. These credits, once created, are "banked" to be retired later by the same facility in order to permit new emissions, or can be sold to other facilities for use.[189] Again, just like in *Lotus*, the use of emission reduction credits to offset an increase in emissions is not a project component, but rather akin to a potential mitigation measure.[190] The DEIR should thus conclude that the emissions from this Project are significant, and separately propose enforceable and monitorable mitigation measures.

G1-86.44 cont'd.

Failure to properly analyze the significance of the VOC emissions of this Project means that SCAQMD has failed to evaluate whether "other more effective measures than those proposed should be considered."[191] CEQA requires that "[w]here several measures are available to mitigate an impact, each should be discussed and the basis for selecting a particular measure should be identified."[192] But here, by inappropriately including offsets as part of the Project, SCAQMD has failed to discuss why offsets were chosen in favor of other on-site mitigation. On-site mitigation could include shutdown of additional equipment at the refinery, or installation of control technology to reduce operational emissions from the new components. These options should be disclosed as potential mitigation measures, and their effectiveness discussed.

G1-86.45

Under CEQA, mitigation measures must be enforceable and effective, and there must be a mitigation monitoring and reporting program in place to ensure compliance.[193] There is no evidence in the EIR of what emission reduction credits Tesoro plans to use to offset emissions, and that these credits are valid. We submitted a Public Records Act request for information on the credits on May 9, but SCAQMD failed to provide records before the comment deadline.[194] As the Ninth Circuit has pointed out—EPA has never validated the emission credits in the ERC bank, so there is no guarantee that the credits used for this project are valid.[195] To the extent Tesoro proposes to use emission reduction credits as mitigation measures, the credits proposed to be used should be disclosed and their validity analyzed.

G1-86.46

[186] *See* CEQA Guidelines, § 15064.7(a).
[187] DEIR, at 4-16 - 4-17, Table 4.2-4.
[188] DEIR, at 4-36; DEIR, at 4-16 - 4-17, Table 4.2-4.
[189] SCAQMD Rule 1309.
[190] CEQA Guidelines, § 15370(e)
[191] *Lotus, supra*, 223 Cal.App.4th at 656.
[192] CEQA Guidelines, §15126.4(a)(B).
[193] *Federation of Hillside and Canyon Assns. v. City of Los Angeles* (2000) 83 Cal.App.4th 1252, 1261; CEQA Guidelines, at §§ 15126.4(a)(2), 15097; *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099, 1115-17.
[194] *See* Public Records Act Request (May 9, 2016).
[195] *Communities for a Better Environment v. U.S. E.P.A.* (9th Cir. 2015) 609 Fed.Appx. 461, 462.

But more importantly, there is no evidence that the use of emission reduction credits will effectively mitigate the harm to the local community from exposure to increased VOC emissions onsite from this Project. Emission reduction credits could have been generated from any location within the South Coast Air Quality Management District—a 10,743 square mile area,[196] and the emission reductions could have occurred decades ago.[197] The Wilmington/Carson area, home to predominantly low income communities of color, is already overburdened by pollution, due to being home to the largest concentration of refineries in the state, proximity to the Port of Los Angeles, and presence of heavy diesel truck and rail traffic.[198] This Project's significant addition of VOC emissions is likely to only exacerbate the pollution burden of these communities, and lead to increased health conditions such as asthma and other respiratory ailments.[199] The DEIR contains no demonstration of how the use of offsets would somehow reduce this localized increase in exposure to VOCs to less than significant, and how the use of offsets would be superior mitigation to other on-site measures.

G1-86.47

B. Early Compliance with the NOx RECLAIM Shave and Retention of RTCs Does Not Equate to Emissions Reductions.

The DEIR proposes to mitigate the significant construction impacts by early compliance with installation of Selective Catalytic Reduction (SCR) on three units. Importantly, we are deeply disappointed that the SCAQMD has a NOx RECLAIM program that means refineries could delay installation of SCRs for many years when "[t]hese change-outs would not require additional approvals and would not require major construction."[200] But beyond this flaw in the NOx RECLAIM program, the DEIR cannot rely on these "early" compliance projects for the NOx RECLAIM to claim credit for mitigation. Importantly, there is nothing in the DEIR that commits to retiring any credits associated with this project. Thus, Tesoro could simply sell any credits generated or use the credits for other emissions, which would provide no NOx benefits to the region. Overall, if this strategy is being used to mitigate the significant construction impacts, there must be a surrender of the RTCs to make any reductions associated with the new SCRs enforceable.

G1-86.48

[196] *See* http://www.aqmd.gov/home/about.

[197] *See generally,* SCAQMD Rule 1309; *see also* Rule 1303(b)(3) [limiting Tesoro to obtaining new emission reduction credits originating in zone 1, which includes the coastal portions of SCAQMD, including Catalina Island].

[198] *See* The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California, *available at* http://www.cbecal.org/wp-content/uploads/2012/05/wilmington_refineries_report.pdf; Morello-Frosch, et al., *Integrating Environmental Justice and the Precautionary Principle in Research and Policy Making: The Case of Ambient Air Toxics Exposures and Heath Risks among Schoolchildren in Los Angeles,* 584 Annals of the American Academy of Political and Social Science 47 (Nov. 2002), attached as Exhibit A.

[199] *See, e.g.,* Ware, et al., *Respiratory and Irritant Health Effects of Ambient Volatile Organic* Compounds, 137-12 Am. J. of Epidemiology 1287 (June 15, 1993) [correlating exposure to VOCs with increased rates of asthma and chronic lower respiratory symptoms], attached as Exhibit B; Curtis, et al., *Adverse Health Effects of Outdoor Air Pollutants,* 32 Environment International 815 (2006) [meta analysis linking exposure to outdoor air pollution, including exposure to VOCs, to many types of health problems], attached as Exhibit C.

[200] DEIR, at 4-40.

Also, the DEIR misleads decision-makers in assuming that the FCCU that will be shut down in Wilmington will actually achieve emissions reductions. This is nothing more than sleight of hand. Tesoro plans to keep 491.63 of NOx RECLAIM Trading Credits (RTCs) to be used for its operations. Thus, characterizing the closing of the FCCU as an actual emission reduction project is misleading because Tesoro plans to keep these reductions to allow it to continue to emit NOx or increase its NOx emissions. This violates CEQA informational disclosure requirement. If Tesoro intends to rely on the reductions, it must retire any RTCs associated with the shutdown of the FCCU in Wilmington permanently. G1-86.49

C. The Air Quality Cumulative Impact Analysis is Flawed.

The DEIR falsely concludes that there is a not a significant cumulative impact related to operations of this project, in addition to other projects in the vicinity.[201] The DEIR comes to this conclusion based on two false assumptions. First, the DEIR assumes that the Southern California International Gateway (SCIG) Project will result in major emissions reductions in the project area.[202] Second, the DEIR relies on the false assumption that unless there are significant direct project impacts, there cannot be cumulative operational impacts from a Project. These assumptions are not supported in the DEIR and contradict CEQA's mandates. G1-86.50

The DEIR cannot rely on reductions from the SCIG project. The SCIG project is a near-dock intermodal railyard proposed to be built in Los Angeles adjacent to west Long Beach. The project was an immensely important environmental justice and health case that garnered significant opposition. Importantly, several entities filed lawsuits challenging the SCIG project, including the SCAQMD itself.[203] The SCAQMD and others challenging the project prevailed in that litigation, and they have received a favorable decision by the Superior Court.[204] In fact one of the critical issues in which the SCAQMD prevailed was whether the EIR could assume reductions in operations at another railyard based on opening this wholly new railyard. The SCAQMD also prevailed on several other issues related to the air quality analysis. This agency flatly critiqued the validity of the emissions reductions estimates in the SCIG project, so these reductions cannot be relied upon in the DEIR. Moreover, the strength of the SCAQMD's arguments were further bolstered in the strong court opinion showing the SCIG EIR is unlawful. G1-86.51

Even beyond the dramatic underestimation of pollution that these comments and the May Technical Report have identified, using the emissions estimates in the DEIR, there will be increases in VOCs, NOx, PM10 and PM2.5 associated with this Project.[205] Without the unsubstantiated SCIG reductions, Table 5-2-2 emissions add up to: 646.97 lbs/day of VOCs, G1-86.52

[201] DEIR, at 5-19.
[202] DEIR, at 5-18, Table 5.2-2 [Finding the SCIG project results in a reduction of 316 lbs/day VOC, 2,905 lbs/day CO, 5,619 lbs/day NOx, 139 lbs/day SOx, 313 lbs/day PM10, and 228 lbs/day PM2.5].
[203] Petition of SCAQMD challenging SCIG Project, attached as Exhibit D. For context of the legal arguments and the critiques of the air quality analysis and the assumptions that formed this analysis, these comments include Attachments E and F, which are the Opening and Reply Briefs filed by SCAQMD in that case.
[204] Decision in SCIG Case, attached as Exhibit G.
[205] *See generally* DEIR section 4.2.

825.15 lbs/day of CO, 832.01 lbs/day of NOx, 3.63 lbs/day of SOx, 340.46 of PM10, and 51.37 lbs/day of PM2.5.

Table: 12: Cumulative Operational Emissions (lbs/day) are significant with the SCIG subtracted

	VOC	CO	NOx	SOx	PM10	PM2.5
6 ILWU Local 13 Dispatch Hall(b)	19.9	--	26.9	--	16.9	1.5
8 Valero Cogen(c)	33.4	201.8	0	0	95.8	20.6
9 WesPac(d)	-27	-266	-40	<1	-33	-30
10 LAUSD Span K-8 School(e)	8.76	--	--	--	--	--
12 Warren E&P(f)	19	14.4	20.5	--	3.7	4.3
15 Sepulveda/Panama Project(g)	339.1	546.9	521.6	2.82	203.9	32.4
16 Shell Revitalization Project(h)	50.83	0	0	0	0	0
21 Phillips 66 Crude Oil Storage(i)	166.8	109.1	249.4	0.3	18.9	12.8
22 Carson Facility E10 Project(j)	0	0	0	0	0	0
23 Carousel Tract(k)	30	200	50	0.48	32	9.1
32 CSULB Foundation Retail Project(l)	4.89	18.95	3.61	0.03	2.26	0.67
34 Tesoro LPG Recovery Unit	0.46	0	0	0	0	0
35 Tesoro Dehexanizer Unit	0.68	0	0	0	0	0
40 Tesoro Storage Tank 956	0.15	0	0	0	0	0
Total	**646.97**	**825.15**	**832.01**	**3.63**	**340.46**	**51.37**
Operational Significance Thresholds	55	550	55	150	150	55
Significant?	**Yes**	**Yes**	**Yes**	No	**Yes**	No

When combining the Project emissions with the additional emissions from the projects identified in Table 5.2-2 on page 5-18, there will be a significant increase cumulatively in emissions.

Because the evidence clearly shows the cumulative impacts – even using the underestimated emissions estimates in the DEIR – exceed SCAQMD significance thresholds, there is no basis for the DEIR's conclusion that no significant increase in cumulative air quality emissions exists.

G1-86.52 cont'd.

Further, the Project cannot shield itself from identifying a significant cumulative air quality impact by relying on the SCAQMD policy that generally allows projects to conclude no significant cumulative air impact when direct project emissions are below significance thresholds. This SCAQMD policy undermines CEQA's requirement to look at the incremental effects of a project when viewed in connection with the effect of past projects, other current projects, and probably future projects.[206] This SCAQMD policy renders the cumulative impacts analysis meaningless, which is not supported by the CEQA Guidelines and CEQA itself. This is particularly the case here where the DEIR itself shows other projects adding significant pollution levels in the project vicinity. Including the additional pollution from the Project makes this

G1-86.53

[206] CEQA Guidelines, §§ 15064(h)(1), 15065(a)(3).

significant impact even greater, requiring disclosure and a significance determination under CEQA. G1-86.53 cont'd.

Because there is clearly a significant cumulative air quality impact from operation of this project, the EIR must be recirculated. G1-86.54

D. The Project's Climate Change and Greenhouse Gas Emissions Impacts are Underestimated.

The DEIR inadequately and inaccurately analyzes the GHG impacts from the Project. As described above, the DEIR fails to admit the likelihood that the facility will shift its operations to process Bakken or tar sands crude oil. This omission precludes an adequate assessment of potentially significant environmental impacts, including the potential increase of GHGs. It precludes meaningful mitigation, and the only alternative that would address its impacts is the No Project Alternative. Further, the DEIR claims beneficial GHG impacts of the Project, despite the fact that, even if the Project were exactly as described, Tesoro anticipates trading GHG allowances for the emissions reductions, resulting in no cumulative benefit at all. The DEIR is extremely deceptive in describing the Project as having climate change benefits, directly undermining its informational purpose. In addition, the DEIR errs in relegating analysis of GHGs solely to the cumulative impacts analysis. The Project's direct and indirect impacts must be analyzed, independently of cumulative impacts. G1-86.55

1. The DEIR Fails to Describe and Analyze Significant Climate Change Implications of this Project.

The DEIR recognizes that climate change is an important problem for our future although it is mildly stated compared to the severe threats.[207] GHGs, especially combustion of fossil fuels for energy, transportation, and manufacturing, are the main contributors to global warming that causes rapid changes in the way a number different types of ecosystems typically function. Climate change, due to GHG emissions, also creates disastrous health effects. For example, higher temperatures lead to increased formation of ground-level ozone, projected to undermine smog reduction progress made in Southern California. Ozone is a well-known lung irritant and a major trigger of respiratory problems like asthma attacks. Local changes in temperature and rainfall also alters the distribution of some waterborne illnesses and diseases. For example, warmer freshwater makes it easier for pathogens to grow and contaminate drinking water.[208] Climate change also threatens California's agriculture and water supplies, causes extreme weather events, sea level rise, and threatens catastrophic change worldwide. G1-86.56

In the face of these severe global and local effects, the DEIR fails to admit a climate change impact that is significant and unavoidable. The DEIR concludes that "the proposed project is expected to result in local GHG emission reduction of approximately 66,139 metric tons per year, providing a net GHG emission reduction from the Refinery, thus, reducing the Refinery's contribution to global climate change."[209] This conclusion is incorrect on at least two

[207] DEIR, at 5-22.
[208] *Id.*
[209] *Id.* at 5-26.

bases. First, as described above, the DEIR fails to admit the likelihood that the facility will shift its operations to process a different crude slate, including more Bakken or tar sands crude oil. In addition to being fatal to the Project Description, and pervasively throughout the DEIR, the DEIR's failure to account for this potential shift is a serious flaw in its cumulative impact analysis. Second, while asserting that the Project reduces GHGs, the DEIR admits that, under the AB 32 regulatory scheme, the Project does not reduce GHG emission, but rather must be assumed to be neutral.[210] It is not clear, based on the DEIR, whether Tesoro intends to claim reductions from the Project as credits under the AB 32 trading program. This lack of clarity renders the DEIR incomplete and deceptive. Moreover, in calculating the GHG emissions for the Project, the DEIR fails to include the life-cycle emissions of the crudes the Refinery processes daily. By failing to include these emissions, the Project inaccurately reports the emissions of the Refinery. Additionally, the DEIR only considers the cumulative impacts of GHG emission and does not include any direct or indirect analysis for GHG emission. All these deficiencies create an inadequate analysis of GHGs.

G1-86.56 cont'd.

a. The DEIR Fails to Analyze a Switch to Heavier and Dirtier Crude Slate due to the Project.

First, the DEIR fails to include the composition of the Refinery's crude slate to determine its current baseline of GHG emissions.[211] According to the DEIR, the crude slate processed by the Refinery is business confidential information and therefore cannot be disclosed by the Refinery.[212] However, this undisclosed data from the Refinery "does not meet the "informational" goals of CEQA."[213] In *Richmond*, the California Appellate Court invalidated an EIR that relied in part on expert testimony using undisclosed, proprietary industry data from Chevron.[214] Similarly, here, the DEIR relies on an expert report to determine that the crude slate will not change.[215] However, this determination is based on analyzing crude slate data unavailable to the public in the DEIR. Withholding the crude slate data prevents "the information necessary for an informed decision from reaching the decisionmakers and the public."[216] The DEIR needs to disclose its current crude slate as well as its anticipated change due to the Project in order to comply with CEQA.

G1-86.57

Second, the DEIR claims that despite the changes made to the Refinery, the proposed facility will only process a crude slate similar to the crude slate currently processed.[217] However, the Project will very likely lead to the processing of a different crude slate that will result in higher GHG emissions.[218] Many of the improvements to the Refinery will allow the processing of a different crude slate. For example, the increased storage and new storage tanks will allow for

G1-86.58

[210] *Id.* at 5-26.
[211] May Technical Report, § I.
[212] DEIR, at F-7 (McGovern Report, Appendix F).
[213] *See Richmond*, 184 Cal.App.4th 70, 88.
[214] *Id.*
[215] DEIR, at F-7 (McGovern Report, Appendix F).
[216] *Richmond*, 184 Cal.App.4th at p. 88.
[217] DEIR, at 1-18.
[218] May Technical Report, § IV(C)(2). .

the handling of Canadian tar sands and Bakken crude.[219] The Project also plans to expand its sulfur treatment operations allowing for the processing of crude oil higher in sulfur such as Canadian tar sands.[220] In addition, the DEIR admits the facility will most likely be switching away from the Alaskan North Slope crude oil due to its lack of availability.[221]

G1-86.58 cont'd.

Tesoro has informed its investors that it will be supplying more advantaged crude oil to the West Coast.[222] Tesoro is currently undertaking a joint project with Savage to construct a crude-by-rail to oil tanker marine terminal in Vancouver, Washington to export advantaged crude oil to the West Coast.[223] With the construction of the Washington marine terminal, Tesoro will increase its capacity to import heavy crude from Canada and light crude from the Bakken oil fields in North Dakota.[224] The May Technical report finds that extraction and transport of both these crudes increase greenhouse gases.[225] Tesoro has expressed its intentions of using the marine terminal to ship crude oil from mid-continent North America (most likely Bakken crude) to West Coast oil refineries.[226] The Project will allow the Refinery to accept these new sources of oil including Canadian tar sands and the crude from the Bakken oil fields.[227] In addition, with this Project, the Refinery has the potential to process up to 50% California heavy and Bakken crude oil, up from 15%.[228]

G1-86.59

Despite this evidence, the DEIR then states that the Refinery will continue to use a similar crude slate by mixing the dirtier crude oils with cleaner crude oils from around the world.[229] However, the DEIR assumes the composition of the crude slate will remain relatively similar but does not include any data as evidence. As in *Richmond*, the DEIR "does not provide any objective quantification" as to the crude slate being used and the crude that will be used.[230] In order to act as a proper informational instrument under CEQA, the DEIR needs to provide more than conclusory statements.

G1-86.60

Even if the characteristics of the crude slate were similar, the sources of the crude oil would not be. For example, the characteristics of Alaskan North Slope oil can be approximated by blending Canadian tar sands and Bakken crude.[231] Although the characteristics such as sulfur content and API gravity would be similar, the GHG impacts from this switch would not be. And

[219] May Technical Report, § IV(C).
[220] May Technical Report, § IV(C)(2).
[221] DEIR, at 2-16.
[222] Morgan Stanley Corporate Access Day, Tesoro Corporation, 15 (May 12, 2016), *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.
[223] https://www.vancouverenergyusa.com/.
[224] Tesoro Investment Thesis, July 24, 2013, *available at* http://analysisreport.morningstar.com/stock/archive?t=TSO&region=USA&culture=en-US&productcode=MLE&docId=604033.
[225] May Technical Report, § IV.
[226] May Technical Report, § II(C).
[227] May Technical Report, § II(C)..
[228] Simmons Energy Conference, *Transformation through Distinctive Performance*, February 27, 2014, *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations.
[229] DEIR, at 1-18.
[230] *Richmond* , 184 Cal.App.4th at 87.
[231] May Technical Report, § III(C).

despite these indications of switching the crude slate at the Refinery, the DEIR does not analyze the GHG emissions from this likely switch.

G1-86.60 cont'd.

The DEIR fails to analyze the impact of GHG emissions from the change in the crude slate. Increased emissions from the Project include, but are not limited to, GHG emissions from increased use of Bakken crude, as compared to the current baseline feedstock. However, this impact cannot be adequately analyzed since the baseline is not provided in the DEIR.[232] In addition, changing the crude stock to include Canadian tar sands and Bakken crude can increase GHG emissions at the refinery itself. The climate change impacts of refining are correlated to the quality of the feedstock refined and changing the feedstock would therefore change the climate change impacts.[233] Generally, heavier crude oils have higher GHG emission intensities based over the life cycle of the oil.[234] Crude oils higher in sulfur and heavier crude oil are more GHG intensive because they require additional energy to crack, coke and de-sulfurize.[235] Based on the world oil prices and evidence from Tesoro's statements, a switch to heavier and more GHG-intensive crude is reasonably foreseeable and therefore should be included in the DEIR. Under CEQA, an EIR must analyze the environmental impacts of future expansion or other actions if this other action is a reasonably foreseeable consequence of the initial project.[236] Thus, the DEIR does not comply with CEQA because it is "inconsistent and obscure" as to whether the Project will process a different crude slate and the resulting GHG emission impact is not included in the DEIR.[237]

G1-86.61

b. Because Tesoro Intends to Claim Credits, Rather Than Allowing GHG Emission Reductions to Improve the Environment, DEIR Assertions that the Project Has GHG Emission Benefits are Deceptive.

The DEIR continuously reiterates the beneficial GHG impacts of the Project.[238] However, these benefits are misleading and do not accurately describe the impacts of the Project. If the Project were exactly as described, Tesoro anticipates securing GHG credits under the new Cap and Trade Program for the emissions reductions, resulting in no air quality benefit at all.[239] The DEIR is extremely deceptive in describing the Project as having climate change benefits, directly undermining its informational purpose.

G1-86.62

[232] *See Richmond*, 184 Cal.App.4th at 89 (holding that failure to identify the possibility that the project would allow the refinery to change its crude stock raises concerns about appropriate baseline against which to compare impacts).
[233] *See generally* Karras, Greg, "Combustion Emissions from Refining Lower Quality Oil: What is the Global Warming Potential," *Environ. Sci. Technol.* 44, 9584-9589 (2010), for an analysis of the significant increases in GHG emissions caused by refining dirtier, heavier crudes from increased energy intensity needed to refine these oils and from direct emissions from the refining process.
[234] CARNEGI ENDOWMENT FOR INTERNATIONAL PEACE, KNOW YOUR OIL: CREATING A GLOBAL OIL-CLIMATE INDEX, http://carnegieendowment.org/files/OCI_TwoPager.pdf.
[235] May Technical Report, § IV(C)(2).
[236] *Laurel Heights Improvement Assn.* 47 Cal.3d at 396.
[237] *See Richmond*, 184 Cal.App.4th at 89.
[238] DEIR, at 1-5.
[239] *Id.* at 5-26.

Under the Cap and Trade Program of AB 32, the state allocates a certain amount of allowances for the entire state and then apportions these allowances to all the facilities that emit GHG.[240] No polluter is allowed to emit GHGs without an allowance. Before apportioning the allowances, the state keeps four percent of the allowances in reserve and then holds ten percent to sell in an auction where companies may buy allowances to make up for their additional emissions.[241] Once these allowances have been withheld, the state then calculates how many free allowances each facility is given using a complex formula that takes into account the facility's previous output.[242] If a facility produces fewer emissions than the amount of free allowances allotted, the facility could bank the allowances to use in years where its emissions exceed the allowances allotted by the state.[243] Additionally, it could sell the allowances on the secondary market to other facilities that need allowances.[244]

G1-86.63

The DEIR claims that the Project will lead to a net reduction of GHGs, thereby potentially falling under its allotted allowances.[245] In fact, the DEIR continuously states the Project will improve air quality. However, in assessing the cumulative impacts, the DEIR then states that the reductions in GHG emissions will then be reintroduced to the AB 32 Cap and Trade Allowance Program.[246] This could mean that Tesoro is banking these allowances under the cap and trade program. Alternatively, Tesoro could sell its excess allowances to other facilities in the secondary market under AB 32. By doing so, the Project would simply be shifting its GHG impacts to another facility. This shifting would reduce the GHG emissions from the facility but not from the atmosphere. Therefore, whether Tesoro intends to bank or sell its allowances, the Project's GHG impacts will not be positive; at best they would be neutral. By obscuring the climate impacts of the allowance program, the DEIR becomes deceptive and inaccurately reports its GHG emissions and its impacts.

G1-86.64

c. Although Information is Available, the DEIR Fails to Include Life Cycle GHG Emissions from the Project.

Although the South Coast Air Quality Management District ("SCAQMD") requires life cycle analysis when information is available, the DEIR fails to provide a life cycle analysis of the GHG impacts from extracting and burning the oil related to this Project. According to the DEIR, the Project would result in a "net GHG emission reduction" of approximately 66,139 metric tons per year, mainly due to the closure of the FCCU unit in Wilmington.[247] However, this calculation of GHG emissions fails to include the life cycle emissions of the crude oil

G1-86.65

[240] Cal. Code Regs., tit., 17 § 95841.
[241] Cal. Code Regs., tit., 17 § 95870 (a)–(b).
[242] Cal. Code Regs., tit., 17 § 95891(b).
[243] Cal. Code Regs., tit., 17 § 95922(a).
[244] ENVIRONMENTAL DEFENSE FUND, CARBON MARKET CALIFORNIA 11, http://www.edf.org/sites/default/files/content/ca-cap-and-trade_1yr_22_web.pdf.
[245] DEIR, at 5-26.
[246] *Id.* at 5-26, Table 5.2-8.
[247] *Id.* at 5-26.