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TESORO
LOS ANGELES REFINERY

INTEGRATION AND COMPLIANCE PROJECT

FINAL
ENVIRONMENTAL IMPACT REPORT

VOLUME VI: Appendix G (Comment G1-78.167 – G1-81 Attachment 23)

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Comment G1-78.167

The composition of some typical diluents/condensates is reported on the website, www.crudemonitor.ca.[191] The specific diluents that would be present in imported crudes is unknown. However, the CrudeMonitor information indicates that diluents contain very high concentrations of the TACs benzene, toluene, ethyl benzene, and xylenes, much higher than included in the health risk assessment. The sum of these four compounds is known as "BTEX" or benzene-toluene-ethylbenzene-xylene. The DEIR does not disclose the BTEX concentrations in the baseline crude slate nor the BTEX concentrations in the range of crudes that could be imported. Rather, it contains only a single mass fraction crude vapor speciation profile that is used only to estimate TAC emissions from tanks and fugitive components.

The CrudeMonitor information also indicates that these diluents contain elevated concentrations of volatile mercaptans (9.9 to 103.5 ppm), which are highly odiferous and toxic compounds that will create odor and nuisance problems at the Refinery in the vicinity of the unloading area, crude storage tanks and supporting fugitive components. Mercaptans can be detected at concentrations substantially lower than will be present in emissions from the crude tanks and fugitive emissions from pumps, valves, flanges, and connectors in the baseline.[192] In fact, mercaptans are added to natural gas in very tiny amounts so that the gas can be smelled to facilitate detecting leaks.

Thus, unloading, storing, handling and refining bitumens mixed with diluent would emit VOCs, TACs, and malodorous sulfur compounds, not found in comparable levels in the existing slate of heavy high sulfur local and imported ANS and foreign crudes. There are no restrictions on the crudes, diluent source, or their compositions nor any requirements to monitor emissions from tanks and leaking equipment where DilBit-blended and other light crudes would be handled.

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[191] Condensate Blend (CRW) - http://www.crudemonitor.ca/condensate.php?acr=CRW; Fort Saskatchewan Condensate (CFT) - http://www.crudemonitor.ca/condensate.php?acr=CFT; Peace Condensate (CPR) - http://www.crudemonitor.ca/condensate.php?acr=CPR; Pembina Condensate (CPM) - http://www.crudemonitor.ca/condensate.php?acr=CPM; Rangeland Condensate (CRL) - http://www.crudemonitor.ca/condensate.php?acr=CRL; Southern Lights Diluent (SLD) - http://www.crudemonitor.ca/condensate.php?acr=SLD.

[192] American Industrial Hygiene Association, Odor Thresholds for Chemicals with Established Occupational Health Standards, 1989; American Petroleum Institute, Manual on Disposal of Refinery Wastes, Volume on Atmospheric Emissions, Chapter 16 - Odors, May 1976, Table 16-1.

Response G1-78.167

As explained 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 slate of crude oils purchased by the Refinery or a change in 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. However, numerous misstatements and generalizations regarding diluent and heavy crude oil were made in the comment that should be addressed and corrected. It is also important to note that heavy Canadian dilbit (tar sands) crude oil was processed by the Refinery during the baseline period.

No data is provided in the comment to support the TAC claims. Dilbit crude oils are only 20-30 percent diluent as noted in Comment G1-78.165, and typically contain less than 0.1 to approximately 0.2 percent benzene as noted in Response G1-78.164. This makes dilbit crude oils physically similar to conventional crude oils, which have 0.04 to 0.25 percent benzene; as further described in Response G1-78.164. Response G1-78.157 describes the DEIR analysis of emissions from new and replacement crude oil storage tanks. The analysis was performed using a worst-case hybrid analysis of all the TACs in crude oils currently and potentially processed at the Refinery including dilbit crude oils.

Published data show mercaptans are common in most, if not all, crude oils.[178] Mercaptan is a class of chemicals that include carbon, sulfur, and hydrogen atoms that vary widely in molecular weight (e.g., methyl mercaptan (molecular weight 48), dodecyl mercaptans (molecular weight 202)). Mercaptans added to natural gas are low molecular weight gases at room temperature giving them a low odor threshold and distinctive odor noticeable by the general public. As noted in the comment, these mercaptans are specifically added to natural gas as an odorant, to aid in the detection of natural gas leaks. Mercaptans in crude oil are larger molecules and cover a broad boiling range. Therefore, crude oil mercaptans do not behave similarly to mercaptans in gas transportation. Because crude oil storage and transfer operations are tightly regulated to control storage tank and fugitive emissions, VOCs, TACs, and odors are expected to be controlled (see Master Response 11). In fact, the upper range of mercaptan in dilbit crude oil (approximately 100 ppm) cited in the comment is less than the quantity of mercaptans (171 ppm) that is found in Arab Light crude oil that is frequently processed by the Refinery (see Table 78.152-1). Since the Refinery does not currently experience odor complaints from mercaptans when handling Arab Light crude oil, no significant odor issues would be expected if additional dilbit crude oils are processed.

The comment makes unsubstantiated claims that there are no restrictions on crude oils or diluent sources, their compositions, or monitoring requirements for equipment handling these materials. While the SCAQMD does not restrict sources of crude oils and diluents, there are stringent controls on emissions from these materials at the Refinery. Vapor pressure of material stored in storage tanks is regulated and there are requirements to monitor emissions from storage tanks and fugitive emission sources. Specifically, Title V permit conditions restrict storage tank vapor pressure and SCAQMD Rules 463, 1173, and 1178 require periodic monitoring of storage tank seals and appurtenances and fugitive sources.

[178] Crude oil assays: http://www.bp.com/en/global/bp-crudes/assays.html and Crude oil assays: http://corporate.exxonmobil.com/en/company/worldwide-operations/crude-oils/assays.

Comment G1-78.168

2. Increased Combustion Emissions From Tar Sands Bitumen Not Evaluated

The composition of tar sands crudes is chemically different from other heavy crudes currently processed at the Refinery for two major reasons: (1) presence of large quantities of volatile diluent with high levels of VOCs and toxic chemicals as discussed above and (2) unique chemical composition of the bitumen, the heavy fraction. The previous comment discussed diluent. This comment discusses the unique composition of tar sands bitumens that require more intense processing and thus result in higher emissions not disclosed in the DEIR.

Tar sands bitumens are composed of higher molecular weight chemicals and are deficient in hydrogen compared to conventional heavy crudes. This means more energy will be required to convert them into the same slate of refined products. Thus, most fired sources at the Refinery —heaters, boilers, etc.—will have to work harder to generate the same quantity and quality of refined products. This will increase all utilities required to run the refinery - electricity, natural gas, hydrogen, water, and steam. These increases in emissions were not disclosed in the DEIR. This section discusses these bitumens and their impact on refining emissions.

G1-78.168

Response G1-78.168

As explained 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 slate of crude oils purchased by the Refinery or a change in 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. However, the comment makes numerous claims regarding diluent and heavy crude oil that should be addressed and corrected.

It is true that raw bitumen contains higher molecular weight molecules and fewer low molecular weight molecules. As acknowledged in Comments G1-78.164 and G1-78.165, raw bitumen is not transported or refined in the United States. Raw bitumen is too viscous, or solid, to transport or process. Diluent is added to the bitumen to produce pipeline quality crude oil that is very similar to other heavy crude oils, so it can be pumped and transported to refineries for processing.

Like any other crude oil, dilbit crude oils are and would continue to be mixed with other crude oils to create a crude oil blend that matches what is currently able and permitted to be processed by the Refinery. Since the proposed project does not include modifications to the crude oil processing units to install larger equipment or to increase the capacity beyond the 6,000 bbl/day, as analyzed in the DEIR, no significant changes to energy demand and emissions are expected to occur. As explained in Section 2.5.4.1 on page 2-17 of the DEIR, both Carson and Wilmington Operations crude oil processing capacity is currently constrained by Crude Unit and DCU heater duty permit descriptions. This will preclude the processing of any significant quantity of heavier crude oil including dilbit crude oil. Response G1-78.150 provides an example of the use of Tesoro's crude oil assay software to further define crude oil blend properties. The properties of dilbit crude oils and any other crude oils would be entered into the crude oil assay software to create a crude oil blend that matches what is currently able and permitted to be processed by the Refinery.

Response G1-78.171 addresses the fact that hydrogen use at the Refinery will not change as a result of the proposed project. The Refinery currently uses all available produced and purchased hydrogen such that operations are carefully managed based on the available hydrogen.[179] Given these constraints on Refinery operations, no significant changes to energy demand and emissions could occur absent additional modifications to the Crude Units and DCUs. Response G1-78.150 provides an example of the use of Tesoro's crude oil assay software to further define crude oil blend properties. The properties of dilbit crude oils and any other crude oils would be entered into the crude oil assay software to create a crude oil blend that matches what is currently able and permitted to be processed by the Refinery.

The comment claims that due to their unique composition, bitumens in dilbit crude oil require more intense processing resulting in increased emissions. Contrary to the comment, as shown in Table 78.165-1, the molecular weights of chemicals or constituents in dilbit crude oils are not actually higher than that of other crude oils. Dilbit crude oils, like any other heavy crude oil, just have more of the heavier molecules than lighter crude oils. There are two parts to this discussion; one is for molecules boiling below 1,000 °F, and the other is for molecules boiling over 1,000 °F (the vacuum residue that is sent to the DCUs).

For refinery distillation of molecules boiling below 1,000 °F, the molecular weight of a molecule is the primary driver of its boiling point. Refineries distill crude oil into several distillate fractions. In order for the molecules to boil in these ranges, they have to be of very similar molecular weight. For example, naphtha boils between 50 °F to 325 °F. It does not matter what crude the naphtha came from. The carbon chain length for these molecules is going to be in the range of five to 12 carbon atoms (C5 to C12 range), so their molecular weights will be similar. The naphtha from a dilbit crude oil is the same molecular weight as the naphtha from any other crude oil. The same argument holds true for the kerosene, diesel, and vacuum gas oil. If the molecules were larger from a dilbit crude oil, they would boil in a higher boiling fraction of the oil and be classified differently.

There are some molecules boiling closer to 1,000 °F and some larger molecules boiling at much higher temperatures (i.e., asphaltenes). These molecules also exist in sweet and light sour crude oils. But there are more of the higher boiling molecules like asphaltenes in a heavier and more sour crude oil. Crude oils like dilbits, Basrah, and Arab Heavy have more asphaltenes and other higher boiling components than lighter and sweeter crude oils. Dilbit crude oils do not have larger molecules than crude oils like ANS. Dilbit crude oils and other heavy crude oils, though, have a higher percentage of the larger molecules that are present in all crude oils. The molecules boiling over 1,000 °F are converted in cokers (specifically the DCUs at the Refinery).

Dilbit crude oils and other heavy crude oils cannot be forced to similar conversion rates of lighter oils in the DCUs with additional heat input; they simply convert to a lower volume of liquid

[179] See Attachment C, Declaration of Douglas Miller, Vice President, California Value Chain Strategy of Tesoro Companies, Inc.

product, and a higher volume of solid coke. As explained in Section 2.5.4.1 on pages 2-18 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 for operations to run smoothly and the coke to meet quality specifications. The Refinery already operates at or near these limits (see page 2-18 of the DEIR), so there is no room for more heavy molecules or more heavy crude oils than are currently processed. Dilbit crude oils, and any other heavy or light crude oils would be evaluated and proportionally mixed into an appropriate crude oil blend for processing by the Refinery (as described on page 2-14 of the DEIR and Responses G1-78.150, G1-78.170, and G1-78.172, additional crude oil evaluations are performed prior to mixing individual crude oils into the blend to be processed by the Refinery).

Hydrogen deficiency of dilbit crude oils is similar to hydrogen deficiency of other heavy sour crude oils. As explained in Response G1-78.171, the Refinery operates to its hydrogen limit (i.e., the Refinery currently uses all available Refinery-produced and externally purchased hydrogen). There is no other capacity available for producing hydrogen for use in the Refinery. In other words, there cannot be increased emissions associated with increased hydrogen production.

Processing dilbit crude oil would be like processing any other heavier sour crude oil; the amount processed would need to be a small enough amount to stay within the current safety, operational, and environmental limitations on the Refinery process units. Examples of these limitations include TAN limits described on page 2-19 of the DEIR for metallurgy or safety considerations, the coking cycle times described on pages 2-17 and 2-18 of the DEIR for operational limitations, and heater duty permit descriptions as explained on page 2-17 of the DEIR for environmental limitations. Catalyst capacity, hydrogen supply, sulfur plant limits, and coke quality all limit how much of each molecular compound type can be processed, and these limits are already constrained with the current crude oil blend. The overall amount of large, hydrogen deficient molecules processed cannot increase from the current crude oil blend.

Comment G1-78.169

Refining converts crude oils into transportation fuels. This is done by removing contaminants (sulfur, nitrogen, metals) and breaking down and reassembling chemicals present in the crude oil charge by adding hydrogen, removing carbon as coke, and applying heat, pressure, and steam in the presence of various catalysts. More intensive refining is required to convert tar sands crudes into useful products than other heavy crudes, regardless of the API gravity and sulfur content of the final blend. This means a greater amount of energy must be expended to yield the same product slate. Thus, all of the combustion sources in a refinery, such as heaters and boilers, must work harder and thus emit more pollutants, than when refining conventional heavy and other crudes. The DEIR fails completely to analyze the impact of crude composition on the resulting emissions from generating increased amount of these utilities. G1-78.169

Canadian tar sands bitumen is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular weight polymeric material.[193] Crudes derived from Canadian tar sands bitumen—DilBits and SynBits—are heavier, i.e., have larger, more complex molecules such as asphaltenes,[194] some with molecular weights above 15,000.[195] They generally have higher amounts of coke-forming precursors; larger amounts of contaminants (sulfur, nitrogen nickel, vanadium) that require more intense processing to remove; and are deficient in hydrogen, compared to other heavy crudes. These differences lead to many refining challenges -- naphthenic acid corrosion, subtle TAN changes, desalter upsets, preheat train fouling[196] – that can increase emissions.

Thus, to convert tar sands crudes into the same refined products requires more utilities -- electricity, water, heat, and hydrogen. This requires that more fuel be burned in most every fired source at a refinery and that more water be circulated in heat exchangers and cooling towers. Further, this requires more fuel to be burned in any supporting off-site facilities. Under CEQA, these indirect increases in emissions caused by a project must be included in the impact analysis. These increases in fuel consumption release increased amounts of NO_x, SO_x, VOCs, CO, PM10, PM2.5, and TACs as well as greenhouse gas emissions (GHG). Some of the principal differences are identified below, followed by a discussion of the impacts these differences have on emissions. G1-78.169 cont'd.

[193] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.

[194] Asphaltenes are nonvolatile fractions of petroleum that contain the highest proportions of heteroatoms, i.e., sulfur, nitrogen, oxygen. The asphaltene fraction is that portion of material that is precipitated when a large excess of a low-boiling liquid hydrocarbon such as pentane is added. They are dark brown to black amorphous solids that do not melt prior to decomposition and are soluble in benzene and aromatic naphthas.

[195] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.

[196] Eric Vetters, Challenges of Processing Canadian Crudes: Low Cost Reliable Operation in a Competitive Business Environment, June 20, 2012, Joint CCQTA/COQA Meeting; Available at: http://www.ccqta.com/files/Challenges%20of%20Processing%20Canadian%20Crudes%20June%202012%20v2a.pdf and Walter Giesbrecht, Challenges of Processing Heavy Canadian Crudes, June 20, 2012, Joint CCQTA/COQA Meeting; Available at: June 20, 2012, Joint CCQTA/COQA Meeting; Available at: http://www.ccqta.com/files/FHR%20CCQTA%20Presentation%202012.pdf.

Response G1-78.169

As explained 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 slate of crude oils purchased by the Refinery or a change in 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. Therefore, higher concentrations of contaminants are not foreseeable and do not need to be addressed in the DEIR. However, numerous misstatements and generalizations are made in the comment regarding diluent and heavy crude oil that should be addressed and corrected.

Most of the claims in the comment are addressed in Response G1-78.168, which discusses the Refinery operational and permit limitations that in turn limit the amount of dilbit, synbit, or other heavy crude oils that can be processed by the Refinery in a crude oil blend. It is also important to note that heavy Canadian dilbit (tar sands) crude oil was processed by the Refinery during the baseline period. Additionally, the asphaltene content of dilbit crude oils is similar to other crude oils such as Basrah and Arab Heavy that are frequently processed by the Refinery; therefore, any potential impacts are already part of the baseline operations and are not unique to dilbit crude oils.

Since the quantity of these crude oils processed is limited by current Refinery constraints, the potential operational issues noted in the comment, including desalter upsets, preheat train fouling and increased utility use, are not expected to occur. It should be noted that the Refinery processed during the DEIR baseline period Cold Lake dilbit crude oil and currently processes Cold Lake and Kearl dilbit and Albian Heavy synbit crude oils as part of its heavy crude oil slate. The quantity of these crude oils processed is currently limited to fit the Refinery constraints; the quantity of these crude oils processed will continue to be limited since the Refinery constraints will not be changed by the proposed project, with the exception of the additional 6,000 bbl/day crude oil capacity increase as analyzed in the DEIR.

See Response G1-78.174 that further addresses any potential issues regarding total acid number (TAN) and naphthenic acids in crude oil.

Comment G1-78.170

3. Higher Concentrations of Asphaltenes and Resins

The severity (e.g., temperature, amount of catalyst, hydrogen) of hydrotreating depends on the type of compound a contaminant is bound up in. Lower molecular weight compounds are easier to remove. The difficulty of removal increases in this order: paraffins, naphthenes, and aromatics.[197] Most of the contaminants of concern in tar sands crudes are bound up in high molecular weight aromatic compounds such as asphaltenes that are difficult to remove, meaning more heat, hydrogen, and catalyst are required to convert them to lower molecular weight blend stocks. Some tar sands-derived vacuum gas oils (VGOs), for example, contain no paraffins of any kind. All of the molecules are aromatics, naphthenes, or sulfur species that require large amounts of hydrogen to hydrotreat, compared to other heavy crudes.[198] G1-78.170

Asphaltenes and resins generally occur in tar sands bitumens in much higher amounts than in other heavy crudes. They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[199] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker. They also form layers of coke in hydrotreating reactors, requiring increased heat input, leading to localized or even general overheating and thus even more coke deposition. This seriously affects catalyst activity resulting in a marked decrease in the rate of desulfurization. They also require more intense processing in the coker to break them down into lighter products. These factors require increases in steam and heat input, both of which generate combustion emissions -- NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

Further, if the crude includes a synthetic crude, SCO, for example, the material has been previously hydrotreated. Thus, the remaining contaminants (e.g., sulfur, nitrogen), while present in small amounts, are much more difficult to remove (due to their chemical form, buried in complex aromatics), requiring higher temperatures, more catalyst, and more hydrogen.[200] G1-78.170 cont'd.

The higher amounts of asphaltenes and resins generate more heavy feedstocks that require more severe processing than lighter feedstocks. The coker, for example, makes more coker distillate and gas oil, that would contribute to the propane would be recovered, compared to conventional heavy crudes. Similarly, the Crude Unit makes more atmospheric and vacuum gas oils,[201] increasing emissions there, including fugitive VOC emissions from equipment leaks and combustion emissions from burning more fuel.

[197] Gary et al., 2007, p. 200.

[198] See, for example, the discussion of hydrotreating and hydrocracking of Athabasca tar sands cuts in Brierley et al. 2006, pp. 11-17.

[199] James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4.

[200] See, for example, Brierley et al. 2006, p. 8 ("The sulfur and nitrogen species left in the kerosene and diesel cuts are the most refractory, difficult-to-treat species that could not be removed in the upgrader's relatively high-pressure hydrotreaters."); Turini et al. 2011, p. 4.

[201] See, for example, Turini et al. 2011, p. 9.

Response G1-78.170

The claims in the comment suggesting that contaminants, asphaltenes, and resins occur in heavy Canadian bitumen in "much higher" concentrations than other heavy crude oils is not correct and is addressed in Response G1-78.168. Some of the statements in the comment discuss bitumen as opposed to dilbit and therefore are about raw bitumen. It is true raw bitumen contains higher molecular weight molecules and few low molecular weight molecules. As acknowledged in Comments G1-78.164 and G1-78.165, raw bitumen is not transported or refined in the United States. Raw bitumen is too viscous, or solid, to transport or process. Diluent is added to the bitumen to produce pipeline quality crude oil that is very similar to other heavy crude oils, so it can be pumped and transported to refineries for processing. Table 78.170-1 compares data for several heavy Canadian crude oil dilbit crude oils (Kearl and Cold Lake) and a range for other heavy crude oils processed by the Refinery, showing that dilbit crude oil properties are within the range of conventional heavy crude oil properties processed at the Refinery during the baseline or in the past 18 months.

Table 78.170-1

Dilbit and Heavy Crude Oil Properties

Asphaltenes		Heavy Molecule Yields (Vacuum Residue BP >1,020 □F)	
Dilbit Crude Oils	**Refinery Crude Oils**	**Dilbits**	**Refinery Crude Oils**
2.8 – 7.6 %	0.05 – 13.2 %	32 – 35 %	5 – 40%

Sources: Dilbit crude oil data is for Kearl and Cold Lake heavy Canadian crude oils (available at http://corporate.exxonmobil.com/en/company/worldwide-operations/crude-oils/crude-by-region) and Refinery Crude Oils - Range of heavy crude oils processed by the Refinery from 1/2015 through 6/2016 provided by Tesoro.

The comment also includes claims regarding synthetic crude oils without providing substantial evidence that any increased synthetic crude oil processing would occur. See Response G1-78.172 that addresses the fact that synbit (synthetic) crude oils have been processed by the Refinery in the past, and, like any other crude oil synthetic crude oil properties, including aromatic sulfur and nitrogen content, would be evaluated for inclusion in the Refinery blend prior to processing.

Additionally, the comment suggests that asphaltene precipitation (i.e., the formation of coke deposits) will occur from blending heavy Canadian bitumen crude oil. First, as noted in Comment G1-78.164, bitumen is blended with diluent into a dilbit crude oil. 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 Refinery has used these compatibility models for many years as the historic and current crude oil slates could be incompatible if blended incorrectly. Heavy Canadian bitumen crude oil is no different from other crude oils in this regard.

The Refinery receives and processes pipeline quality crude oil, which means that any bitumen is actually obtained as dilbit crude oil, as noted in Comments G1-78.164 and G1.78.165, which is then blended to meet the specifications of the Refinery, which naturally provide dilution of properties such as asphaltene concentration. Response G1-78.168 further explains that the asphaltene content of dilbit crude oils is similar to other crude oils such as Basrah and Arab Heavy that are processed by the Refinery. Since the quantity of these crude oils processed is limited to current Refinery constraints, the potential operational issues noted in the comment of increased heat and steam input resulting in increased emissions will not occur.

The comment also contains statements that asphaltenes and resins are higher in bitumen than other heavy crude oils and this would cause problems if the bitumen was put in a hydrotreater. As stated above, the Refinery does not buy and process bitumen, it buys and processes diluted bitumen that is similar to other heavy crude oils. Also, the heavier molecules (asphaltenes, resins, etc.) boil in the vacuum residue range and are processed in cokers, not hydrotreaters. Asphaltenes and high boiling resins are not processed in the hydrotreaters.

Comment G1-78.171

4. <u>Hydrogen Deficiency</u>

Tar sands crudes are hydrogen-deficient compared to heavy and conventional crude oils and thus require substantial hydrogen addition during refining, beyond that required to remove contaminants (sulfur, nitrogen, metals) from non-tar-sands crudes. This again means more combustion emissions from burning more fuel.

G1-78.171

Response G1-78.171

As explained in Section 2.7.2.4 of the DEIR, hydrogen use at the Refinery will not change as a result of the proposed project. Currently, the Refinery produces hydrogen both in processing units and hydrogen plants and purchases hydrogen from the Air Products Carson and Wilmington Plants. The Air Products facilities are operating at capacity and cannot supply the Refinery with additional hydrogen. The Refinery currently uses all available produced and purchased hydrogen (i.e., the Refinery operates to its hydrogen limit) such that operations are carefully managed based on the available hydrogen. Due to stringent low sulfur, aromatics, and other product specifications that require extensive hydrotreating of process unit feedstocks and products, most California refineries, including the Refinery, limit operations based on hydrogen supply. The Refinery hydrogen demand is large (i.e., millions of standard cubic feet per day of hydrogen).

In order to increase hydrogen consumption, additional hydrogen producing equipment (i.e., a new hydrogen generation plant) would need to permitted and installed at the Refinery or at Air Products. The demand for hydrogen supply cannot be met via trucks, as truck capacity is too small to have a significant impact on hydrogen supply for Refinery operations. While the proposed project includes hydrotreating and hydrocracking process modifications that would require more hydrogen, other proposed project modifications will counterbalance the increase since less hydrogen will be required with the shutdown of the Wilmington Operations FCCU (i.e., less hydrotreated gas oil feed to the FCCU). Therefore, the proposed project will not change the hydrogen demand, and the Refinery will remain hydrogen limited.

As explained in Master Response 4, the proposed project does not change the crude oil blend processed at the Refinery other than analyzed in the DEIR. Therefore, no increase in hydrogen demand is expected nor could any be met, so any associated emissions from increased production of hydrogen will not occur.

Response G1-78.168 explains that hydrogen deficiency of dilbit crude oils is similar to hydrogen deficiency of other heavy sour crude oils. Dilbit crude oils and other heavy sour crude oils were processed in the DEIR baseline period and are currently used in the crude oil blends that are processed by the Refinery. Response G1-78.168 also explains that the Refinery already runs at or near its processing constraints for heavy crude oils, so there is no room for more heavy molecules or more heavy crude oils than are currently processed. After implementation of the proposed project, as before implementation of the proposed project, the properties of dilbit crude oils, synbit crude oils, and any other crude oils would be entered into the crude oil assay software to create a crude oil blend that matches what is currently feasible and permitted to be processed by the Refinery.

Comment G1-78.172

5. Higher Concentrations of Catalyst Contaminants

Tar sands bitumens contain about 1.5 times more sulfur, nitrogen, oxygen, nickel and vanadium than typical heavy crudes.[202] Thus, much more hydrogen per barrel of feed and higher temperatures would be required to remove the larger amounts of these poisons from semi-refined products. These impurities are removed by reacting hydrogen with the crude fractions over a fixed catalyst bed at elevated temperature. The oil feed is mixed with substantial quantities of hydrogen either before or after it is preheated, generally to 500 F to 800 F. The amount of hydrogen required for a particular application depends on the hydrogen content of the feed and products and the amount of the contaminants to be removed. Hydrogen consumption is typically about 70 standard cubic foot per barrel (scf/bbl) of feed per percent sulfur, about 320 scf/bbl feed per percent nitrogen, and 180 scf/bbl per percent oxygen removed.[203] G1-78.172

Canadian tar sands crudes generally have higher nitrogen content, 3,000 to >6,000 ppm[204] and specifically higher organic nitrogen content, particularly in the naphtha range, than other heavy crudes.[205] This nitrogen is mostly bound up in complex aromatic compounds that require a lot of hydrogen to remove. This would increase emissions.

First, additional hydrotreating is required to remove them, which increases hydrogen and energy input. Second, they deactivate the cracking catalysts, which requires more energy and hence more emissions to achieve the same end result. Third, they increase the nitrogen content of the fuel gas fired in combustion sources, which increases NO_x emissions from all fired sources that use refinery fuel gas. Fourth, nitrogen in tar sands crudes is present in higher molecular weight compounds than in other heavy crudes and thus requires more hydrogen and energy to remove. Fifth, some of this nitrogen will be converted to ammonia and other chemically bound nitrogen compounds, such as pyridines and pyrroles. These become part of the fuel gas and could increase NO_x from fired sources. They further may be routed to the flares, where they would increase NO_x. G1-78.172 cont'd.

These types of chemical differences between the current crude slate and the new crude slate facilitated by the Project were not addressed at all in the DEIR. The potential increases due to these factors must be estimated relative to the CEQA baseline.

[202] See, for example, USGS, 2007, Table 1.

[203] James H. Gary, Glenn E. Handwerk, and Mark J. Kaiser, Petroleum Refining: Technology and Economics, 5th Ed., CRC Press, 2007, p. 200 and A.M. Aitani, Processes to Enhance Refinery-Hydrogen Production, Int. J. Hydrogen Energy, v. 21, no. 4, pp. 267-271, 1996.

[204] Murray R. Gray, Tutorial on Upgrading of Oil Sands Bitumen, University of Alberta, Available at: http://www.ualberta.ca/~gray/Links%20&%20Docs/Web%20Upgrading%20Tutorial.pdf.

[205] See, for example, James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Appendix A.

Response G1-78.172

As explained in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Responses G1-78.94, the proposed project is not designed to facilitate a change in 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. Therefore, higher concentrations of contaminants are not reasonably foreseeable and do not need to be addressed in the DEIR. Additionally, as described in Response G1-78.94, contaminant removal is not germane to the proposed project. Heavy crude oils are blended prior to processing so that the blend will be within the Refinery's acceptable operating envelope. The Refinery has successfully processed heavy Canadian dilbit crude oil, including Cold Lake, Wabasca, and Kearl dilbit and Albian Heavy synbit crude oils, and other similar crude oils in the past. After implementation of the proposed project, as before implementation of the proposed project, the properties of dilbit crude oils, synbit crude oils, and any other crude oils would be entered into the crude oil assay software to create a crude oil blend that matches what is currently feasible and permitted to be processed by the Refinery.

As described in Response G1-78.171, increasing hydrogen consumption beyond current levels is not an option for the Refinery. In order to increase hydrogen consumption, additional hydrogen producing equipment (i.e., a new hydrogen generation plant) would need to permitted and installed at the Refinery or at the third-party facility that generates hydrogen for Refinery use. These types of modifications are not part of the proposed project. Without the additional hydrogen for hydrotreating, no associated increase in energy demand would occur.

In any event, the claim in the comment, that bitumen crude oil contains more contaminants than typical heavy crude oil is not correct. Tesoro owns detailed confidential data (Master Crude Oil Assays) on the crude oils processed by the Refinery. Based on Tesoro's Master Crude Oil Assays, several Middle Eastern crude oils currently processed by the Refinery, including Basrah, have sulfur contents of approximately three percent, which is in the range of heavy Canadian Cold Lake and Kearl dilbit crude oils processed by the Refinery of 3.7 and 3.8 percent sulfur (see Table 78.146-1). Numerous African and South American crude oils processed by the Refinery have nitrogen contents of approaching 3,000 ppm, which is in the range of the heavy Canadian dilbit crude oil. South American and U.S. crude oils processed by the Refinery have nickel contents above 50 ppm, which is in the range of the heavy Canadian dilbit crude oil. Several South American crude oils processed by the Refinery have vanadium contents above 150 ppm, which is in the range of the heavy Canadian dilbit crude oil[180]. The comment also claims high nitrogen content in dilbit naphtha; this is not correct. The diluent naphtha in the dilbit crude oil comes from natural gas fields and light sweet crude oils. It is low in sulfur and nitrogen and similar to conventional crude oils[181].

It should be noted that crude oil oxygen content is not measured directly in crude oil assays because the only oxygen compounds that have a potential impact on crude oil processing are acids, which are further addressed in Response G1-78.174. Almost all of the oxygen in crude oil is present in the form of carboxylic/naphthenic acids.[182]

[180] ExxonMobil's assay for Cold Lake at the website below show that the diluent portion of Cold lake, a typical Dilbit, is very low sulfur and nitrogen. http://corporate.exxonmobil.com/en/company/worldwide-operations/crude-oils/cold-lake-blend.

[181] Section 2.3 of this report explains that diluent is gas field condensate and imported diluent. https://www.ceaa-acee.gc.ca/050/documents/p21799/81697E.pdf..

[182] James G Speight, The Chemistry and Technology of Petroleum, second edition, Marcel Dekker, Inc., 1991, pages. 239-240.

Comment G1-78.173

6. Higher Concentrations of Metals

The baseline slate includes very little tar sands crudes. Table 1. The Project could increase the import of tar sands crudes. These crudes have higher metal content than the baseline crude slate.[206] These metals, for example, would be partitioned into the coke. The impacts from increases in metal content were not evaluated in the DEIR.

The U.S. Geological Survey (USGS) reported that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil, such as those currently refined from local sources.[207]

G1-78.173

The environmental damage caused by these metal pollutants includes bioaccumulation of toxic chemicals up the food chain and a direct health hazard from air emissions. These metals, for example, mostly end up in the coke and would be present coke dust emissions and coke pile runoff.

Further, larger amounts of coke may be produced by tar sands crudes by than the current crude slate. The metal content of fugitive dust from coke piles could increase to dangerous levels. The California Air Resources Board, for example, has classified lead as a pollutant with no safe threshold level of exposure below which there are no adverse health effects. Thus, just the increase in lead from switching up to tar sands crude is a potentially significant impact that was not disclosed in the DEIR. Accordingly, crude quality is critical for a thorough evaluation of the impacts of a crude switch, such as facilitated by the Project and widely broadcast by Tesoro.

G1-78.173 cont'd.

[206] Straatiev and other, 2010, Table 1; Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils, http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF; F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010, Exhibit 34.

[207] R.F. Meyer, E.D. Attanasi, and P.A. Freeman, Heavy Oil and Natural Bitumen Resources in Geological Basins of the World, U.S. Geological Survey Open-File Report 2007-1084, 2007, p. 14, Table 1, Available at http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf.

Response G1-78.173

It should be noted that the comment references but does not include Table 1, therefore no specific response can be provided. As explained in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 4, and Responses G1-78.94, the proposed project is not designed to facilitate a change in 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. Therefore, higher concentrations of contaminants are not reasonably foreseeable and do not need to be addressed in the DEIR.

Additionally, as explained in Response G1-78.94, contaminant removal is not germane to the proposed project. Heavy crude oils are blended prior to processing to fit into the Refinery's operating envelope. The DEIR discussed the crude oil characteristics, including metals, considered when blending crude oils on page 2-16. Responses G1-78.150 and G1-78.170 address blending considerations and tools, such as Tesoro's crude oil assay software and blending models, that are used to predict and avoid incompatible blends or blends that cannot be processed within the Refinery's operating envelope. The Refinery has successfully processed heavy Canadian bitumen crude oil, including dilbit and synbit crude oils, and other similar crude oils in the past (see Response G1-78.172).

The USGS report cited does not present metals data as summarized in the comment. The USGS report pages 1 and 2 define conventional oil as light crude oil with API gravity greater than 25. The report classifies crude oil as conventional (light), medium, heavy, and natural bitumen. When one appropriately compares the natural bitumen with heavy crude oil data presented in Table 1 of the cited USGS report, the results are much more comparable (ranging from approximately the same for vanadium, sulfur, nitrogen, and nickel, four times more for lead and ten times more for copper). Any metals occurring in bitumen crude oil would be blended down first by the addition of diluent prior to transportation of the crude oil and again by the blending of the dilbit crude oil to meet the operating constraints of the Refinery.

There are no additional impacts from storing or transferring dilbit crude oil with higher metals content prior to blending it for processing in the Refinery. The potential impacts noted in the comment would only be associated with processing straight heavy bitumen crude oil in the Refinery, which would not occur, since straight bitumen is not transported to refineries for processing.

The assumption of high levels of metals in coke dust in the comment is not supported by any data.[183] Additionally, Coke handling operations are strictly regulated in the SCAQMD (e.g., SCAQMD Rule 1158), and uncontrolled release of coke dust would not occur.

[183] CEQA Guidelines § 15204(c): "Reviewers should explain the basis for their comments, and should submit data or references offering facts, reasonable assumptions based on facts, or expert opinion supported by facts in support of their comments."

Comment G1-78.174

7. Higher Total Acid Number (TAN)

Both DilBit and SynBit crudes, which are cost-advantaged North American crudes that could be imported from the VET, have high TAN, which indicates high organic acid content, typically naphthenic acids. These acids are known to cause corrosion at high temperatures, such as occur in many refining units, e.g., in the feed to cokers. As a rule-of-thumb, crude oils with a TAN number greater than 0.5 mgKOH/g[208] are considered to be potentially corrosive and indicates a level of concern. A TAN number greater than 1.0 mgKOH/g is considered to be very high. Canadian tar sands crudes are high TAN crudes. The DilBits, for example, range from 0.98 to 2.42 mgKOH/g.[209]

Sulfidation corrosion from elevated concentrations of sulfur compounds in some of the heavier distillation cuts is also a major concern, especially in the vacuum distillation column, coker, and hydrotreater units. The specific suite of sulfur compounds may lead to increased corrosion. The DEIR does not disclose either the specific suite of sulfur compounds or the TAN for the proposed crude imports. G1-78.174

A crude slate change could result in corrosion from, for example, the particular suite of sulfur compounds or naphthenic acid content. The composition difference could cause significant accidental releases, even if the crude slate is within the current design slate basis. As discussed in Comments II.A.2.c and II.A.2.f, this recently occurred at the Chevron Richmond Refinery in the San Francisco Bay.

These types of accidents can be reasonably expected to result from incorporating tar sands crudes into crude oils processed at the Los Angeles Refinery. Even if the range of sulfur and gravity of the crudes remains the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high TAN and high solids, which aggravate corrosion. The gas oil and vacuum residue piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from tar sands crudes, leading to catastrophic releases.[210] Catastrophic releases of air pollution from these types of accidents were not considered in the DEIR.

Refinery emissions released in upsets and malfunctions can, in some cases, be greater than total operational emissions recorded in formal inventories. For example, a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.[211] G1-78.174 cont'd.

[208] The Total Acid Number measures the composition of acids in a crude. The TAN value is measured as the number of milligrams (mg) of potassium hydroxide (KOH) needed to neutralize the acids in one gram of oil.

[209] www.crudemonitor.ca.

[210] See, for example, Turini and others, 2011.

[211] J. Ozymy and M.L. Jarrell, Upset over Air Pollution: Analyzing Upset Event Emissions at Petroleum Refineries, Review of Policy Research, v. 28, no. 4, 2011.

Response G1-78.174

See Response G1-78.172. As explained 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 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.

All refineries manage the total amount of crude acidity coming to their refinery. The metallurgy and operating conditions of the equipment define each refinery's TAN limit. The Refinery already monitors crude TAN content and purchases a mixture of crude oils that enables the Refinery to operate below its TAN limits. Higher TAN is not unique to dilbit crude oils. There are high TAN crude oils from South America and California being processed globally and at the Refinery.[184] The risk from processing dilbit crude oils is not different than processing other crude oils since dilbit crude oils are already being processed and the necessary controls to monitor and process crude oil blends below the Refinery TAN limits are already in place.

The issue of potential sulfidic corrosion, which caused the piping failure that precipitated the 2012 Chevron Richmond Refinery fire, is addressed in detail in Response G1-78.111. Tesoro has performed the recommended 100 percent component inspection at the Refinery Crude Units, and Tesoro has verified that the Crude Units do not contain low silicon carbon steel piping.

The comment Footnote 210 is incomplete and, therefore, unverifiable.

Comment G1-78.175

III. THE DEIR'S SHIP EMISSION CALCULATIONS ARE FATALLY FLAWED

The Project includes modifications to tanks and pipelines that serve the marine terminals and supply crude oil to the Carson and Wilmington Operations. The Project will replace two 80,000 barrel tanks with two 300,000 barrel tanks at the Wilmington Operations and will add six 500,000 barrel tanks at the Carson Crude Terminal for a total increase in storage capacity of 3,440,000 barrels.[212] Tesoro Logistics, who operates the marine terminals, reports it currently has 97 crude oil, feedstock, and refined product storage tanks with a combined capacity of 6.6 million barrels.[213] Thus, the Project is doubling storage capacity.[214] The increase in crude oil storage capacity at the Carson Terminal alone will increase from a total of 2,028,000 barrels (5 tanks) to a total capacity of 5,028,000 (11 tanks) or by a factor of 2.5. These increases will provide the Los Angeles Refinery with greater flexibility for purchase and blending of crude oils. It may also allow storage and blending of off-specification crude oil.[215] G1-78.175

[212] Increase in tank storage capacity = 6(500,000) + 2(300,000 – 80,000) = **3,440,000 bbl.** The Carson Crude Terminal is south of Sepulveda Boulevard, adjacent to Carson Operations (which is north of Sepulveda Boulevard; see DEIR, p. 2-7.

[213] U.S. Securities and Exchange Commission, Form 10-K, Tesoro Logistics LP, Fiscal Year Ended December 31, 2015 (2015 Tesoro Logistics Form 10-K), p. 8; Available at: http://services.corporate-ir.net/SEC.Enhanced/SecCapsule.aspx?c=242247&fid=14232449.

[214] Increase in storage tank capacity relative to baseline = (6.6+3.44)/6.6 = **1.52**.

[215] SCAQMD Application 567649, pdf 938.

[184] ChevronTexaco Presentation of High Acid Crudes for the Crude Oil Quality Group, January 30, 2003. http://www.coqa-inc.org/docs/default-source/meeting-presentations/20030130high-acid-crudes.pdf?sfvrsn=2 (accessed August 30, 2016).

Response G1-78.175

The comment summarizes the storage tank aspect of the proposed project and presents data on existing storage tanks at the Refinery that are not affected by the proposed project. See Response G1-78.126 for a discussion of the overall change in light crude oil storage capacity at the Refinery from 11 million barrels to 14.4 million barrels. The assumed available crude oil storage capacity in the comment was based only on the storage capacity of Tesoro Logistics, but the Refinery has additional light crude oil storage capacity. Based on the comprehensive evaluation of storage tank capacity available for light crude oil storage described in Response G1-78.126, the proposed increased light crude oil storage capacity is approximately 30 percent. Therefore, the proposed new storage tanks do not represent a doubling in storage capacity.

As described in Master Response 4, the Refinery has historically purchased crude from numerous sources and will continue to do so with or without the proposed project. As explained in Response G1-78.126, the Refinery currently has numerous storage tanks capable of storing crude oil and, as such, has flexibility to store limited quantities of various types of crude oils. The objective of the proposed additional storage capacity is to more efficiently offload marine vessels, which will reduce demurrage fees and reduce vessel emissions (see page 2-4 and pages 4-26 through 4-29 of the DEIR). This occurs because, as described in Master Response 6, large marine vessels that currently unload at Marine Terminal 1 would be able to unload in one visit, avoiding hoteling and maneuvering to anchorage over several days, which results in demurrage charges as well as unnecessary emissions. The additional storage capacity does not facilitate preferential selection of one type of crude oil over another.

The comment Footnote 215 refers to an internal engineering staff's comment on an administrative draft of the DEIR, and is not an authorization for Tesoro to store off-specification crude oil. The application submitted by Tesoro did not include the storage of off-specification crude oil (also referred to as slop oil) in the proposed storage tanks. The comment from engineering staff was subsequently clarified in conversations with Tesoro and the DEIR accurately reflects the expected commodities to be stored in the proposed storage tanks. The Refinery does not import off-specification crude oil. Off-specification oil is generated during the refining process and stored in existing slop oil storage tanks at the Refinery (Tanks 426 and 700 at Carson Operations and Tank 80083 at Wilmington Operations) and is not stored at the Carson Crude Terminal. Therefore, the DEIR correctly analyzed the expected crude oils to be handled at the Carson Crude Terminal.

Comment G1-78.176

The DEIR fails to present any baseline and post-Project throughput and capacity information for the marine terminals that serve the Project[216] even though the Project significantly increases the unloading rate at these terminals and doubles their storage capacity Tesoro has claimed all of the information required to estimate baseline terminal throughput as CBI, thus preventing an estimate of the increase in emissions from increase marine vessel traffic in the usual manner. G1-78.176

The Carson and Wilmington Operations received crude oil in the baseline by ship at three marine terminals operated by Tesoro Logistics Operations, LLC (Tesoro Logistics) in the Port of Long Beach and a marine storage facility that support Tesoro's Los Angeles refinery: (1) Long Beach Terminal Berths B84 and 87 (Wilmington); (2) Marine Terminal 1, Berth 121 (Carson), which is capable of handling a two million barrel capacity crude carrier; (3) Marine Terminal 2 Berths B76-78 (Carson), which is comprised of a two-vessel berth dock; and (4) the Terminal 3 (Carson) storage facility.[217] Tesoro integrated the delivery systems in 2014 for these facilities so that Wilmington currently can access the Carson delivery network.[218] Presumably, after the Project is implemented, these terminals will supply the integrated Los Angeles Refinery. G1-78.176 cont'd.

[216] DEIR, Section 2.6.5.

[217] DEIR, pp. 2-23/27 and Fig. 2-9; 2015 Tesoro Logistics Form 10-K, p. 8.

[218] Thomson Reuters Streetevents Edited Transcript, TSO – Q3 2014 Tesoro Corporation Earnings Conference Call, October 31, 2014 (10/31/14 Q3 2014 Tesoro Earnings Call Transcript), p. 4, Exhibit 14.

Response G1-78.176

The DEIR has fully analyzed the project related impacts at the marine terminal. As presented in Section 2.7.1.9 of the DEIR, the Wilmington Operations marine vessel unloading rate will be increased from 5,000 bbl/hr to 15,000 bbl/hr when unloading to the replacement floating roof storage tanks. The proposed project analyzes an incremental increase[185] of 6,000 bbl/day (2.2 million bbl/yr) for the Wilmington Operations as explained in Section 4.1.2.1 of the FEIR. The proposed new storage tanks for the Carson Operations are explained in Section 2.7.2.11 of the DEIR, and no change to the unloading rate or throughput to the Carson crude oil storage tanks will occur with the proposed project. Section 4.2.2.2.2 of the FEIR (see pages 4-24 through 4-29) analyzes the reduction in emissions associated with the increased unloading rate for the Wilmington Operations including the increased receipt of 2.2 million bbl/yr. No confidential business information was relied on to calculate emission impacts from marine vessels.

Contrary to the claim in the comment, the analysis of proposed project impacts can be completed using the incremental emission increases[186] associated with the project and without the need to disclose the confidential information because both the additional crude oil expected to be delivered and the reduction in hoteling time from the improved offloading rate define and fully disclose the emission changes from the proposed project (see Response G1-78.180).

[185] The project increment, incremental increase, or incremental change is derived from the comparison of the post-project peak activity to the pre-project actual achieved baseline activity.

[186] The project increment, incremental increase, or incremental change is derived from the comparison of the post-project peak activity to the pre-project actual achieved baseline activity.

The Carson crude oil storage tanks would streamline the unloading of the larger marine vessels (i.e., 1.5 to 2.0 million bbl/vessel) that deliver crude oil and eliminate the need for marine vessels to partially unload, relocate to anchor or mooring, return to be partially unloaded again, return to anchor or mooring, and then return to finish unloading the crude oil. As explained in Master Response 6, reducing marine vessel auxiliary engine emissions will substantially reduce marine vessel emissions in the harbor. The expected emission reductions from the improved efficiency of unloading were not included in the analysis of the proposed project impacts to provide a conservative, worst-case analysis.

Further, Terminal 3 is not a marine terminal as it has no berth access and, therefore, does not have the capability of offloading crude oil.

The comment acknowledges integration of the Carson and Wilmington Operations crude oil delivery systems. 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 proposed project will improve the direct pipeline connectivity between the Carson and Wilmington Operations. The environmental impacts of the proposed project pipelines were evaluated in Chapter 4 of the DEIR.

Comment G1-78.177

The information reviewed below, summarized in Figure 10, suggests that the Project is part of Tesoro Logistics' plans to expand its terminals.[219] G1-78.177

Figure 10.

Long Beach Terminal and Los Angeles Pipelines Drop Down Assets

The DEIR asserts that the proposed modifications will increase the unloading rate, reducing the time that ships remain at the terminal (hoteling), thus reducing marine vessel emissions. At Wilmington, the DEIR assumed there would be no increase in VOC emissions because Wilmington currently receives crude oil in only two vessel sizes – Panamax and Aframax -- and will continue to receive crude oil in the same size vessels, even though the crude oil unloading rate is proposed to increase from 5,000 bbl/hr to 15,000 bbl and the storage capacity will increase by 440,000 barrels.[220] There are four major problems with these assumptions. G1-78.177 cont'd.

First, the marine traffic at many of the berths in the baseline did not include any of the larger Aframax vessels. Exhibit 31.

[219] Terminal Agreement, Schedule A, Pipelines.
[220] DEIR, pp. 4-26.

Response G1-78.177

Figure 10 of Comment G1-78.177, while somewhat illegible (a more legible copy is shown in Figure 78.177-1), is a depiction of the assets associated with an asset transfer between Tesoro Refining & Marketing Company and Tesoro Logistics Operations. The transfer occurred in 2012 and involved previously existing Tesoro assets being reassigned between two Tesoro entities. The asset transfer is not related to the proposed project in any way because these operations commenced in 1967 and are ongoing. This was an unrelated activity that is part of the baseline.

The data presented in the comment Exhibit 31 is a collection of unreferenced tables, raw data, and a vessel classification table identifying LR1 as vessels ranging from 45,000 to 80,000 deadweight tons and LR2 as vessels ranging from 80,000 to 160,000 deadweight tons in size. The vessel classification table in comment Exhibit 31(g) has an internet address that leads to an Energy Information Administration (EIA) article about oil tanker classification, and does not contain the table presented in comment Exhibit 31 but contains the graphic shown in Figure 78.177-2. The EIA article describes the Aframax (80,000 to 120,000 deadweight tons) category of marine vessels to be a size that is overlapping between the LR1 (40,000 to 80,000 deadweight tons) and LR2 (80,000 to 160,000 deadweight tons) classes presented in the tables of data in comment Exhibit 31. Panamax marine vessels (50,000 to 75,000 deadweight tons), which are smaller than Aframax, would be included in the LR1 category only. The data referenced in the comment show the baseline years for the Long Beach Marine Terminal (Berths 84 through 87) had combined Panamax and Aframax sized marine vessels visits of 276 and 260 times in 2012 and 2013, respectively (see Table 78.177-1).

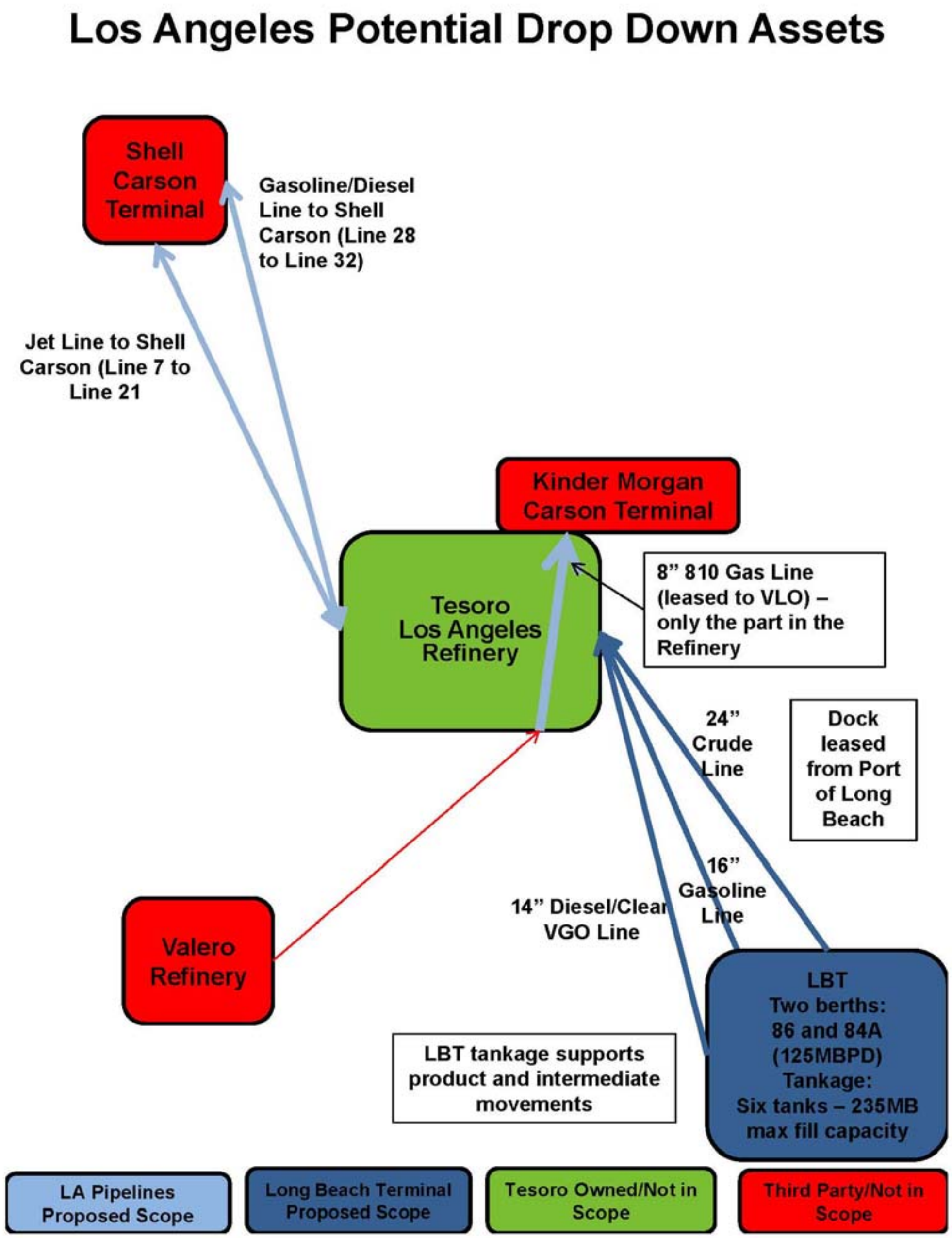
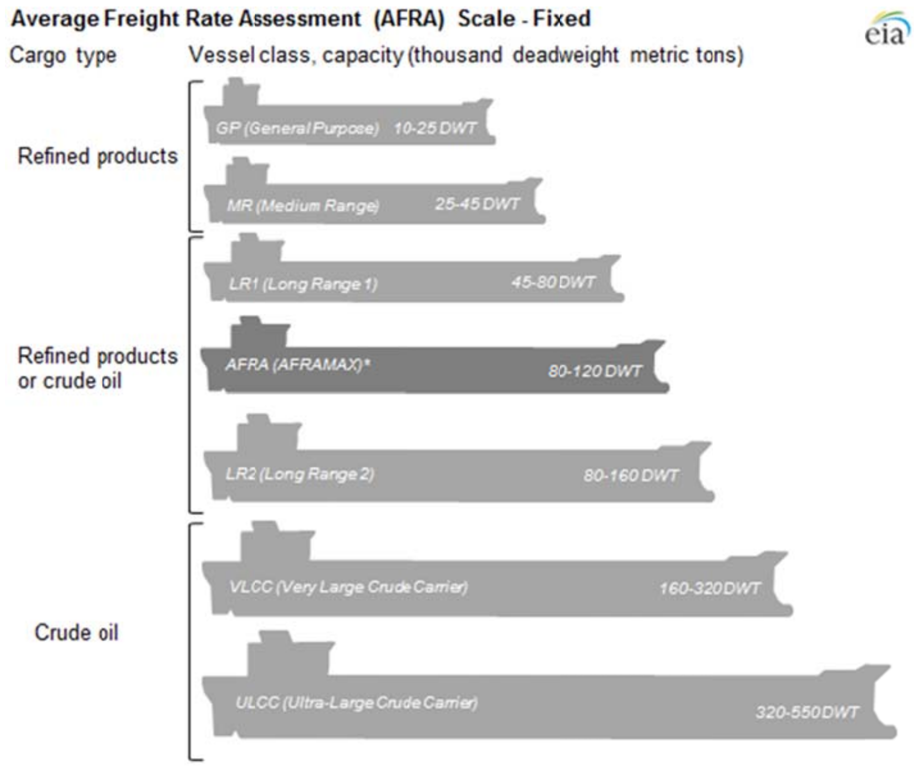


Figure 78.177-1

Long Beach Terminal and Los Angeles Pipelines Drop Down Assets



Source: EIA https://www.eia.gov/todayinenergy/detail.cfm?id=17991 (accessed, July 5, 2016)

Figure 78.177-2

Average Freight Rate Assessment Scale - Fixed

The EIA data relied upon in the DEIR to compile Table 4.2-10 reports the volume of crude oil received per shipment (EIA, 2015a). A Panamax vessel can transport up to approximately 400,000 barrels, while Aframax vessels can transport up to approximately 720,000 barrels. While deliveries of less than 400,000 barrels may be delivered in a Panamax or Aframax, a delivery of greater than 400,000 barrels must be delivered in an Aframax. In 2012, there were several deliveries at the berths over 400,000 barrels (DEIR reference EIA, 2015a). Therefore, contrary to the comment, both the data presented in the comment and the data relied on in the DEIR, show that Aframax marine vessels were received at the Long Beach Marine Terminal in the baseline period.

Table 78.177-1

Comment Letter 78 Exhibit 31 Data
Summary of LR1 and LR2 Marine Vessels
Calling at Long Beach Marine Terminal (Berths 84 through 87)

Marine Vessel Type	Berth					Total
	84	84A	86	B84	B86	
2012						
LR1	5	9	8	87	131	240
LR2	0	0	0	3	33	36
LR1 and LR2						276
2013						
LR1	13	14	2	87	123	239
LR2	0	0	0	1	20	21
LR1 and LR2						260

Source: Summarized from Comment Letter 78, Exhibit 31.
Note: As shown in Figure 78.177-1, 80,000 deadweight ton Aframax vessels are included in the LR1 marine vessel type and larger Aframax vessels are included in LR2 marine vessel type.

Comment G1-78.178

Second, these refineries were originally designed to process San Joaquin Valley and other local California crudes,[221] which remains a major supply for Wilmington. Carson was later expanded to also refine Alaska North Slope, which remains a major supply for Carson.[222] However, it is well known that the production of these local California crudes has been declining, as has supply from Alaska. The Senior Director, Market Analysis, and Senior Economist for Tesoro, recently testified:

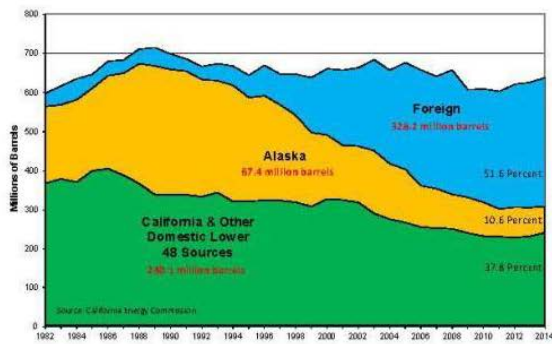
> "During my approximately 10 years tenure at Tesoro, the combined production of California and Alaska has declined approximately 350 MPD which is the supply to 3 average West Coast refineries…Thus, this decline in production is expected to continue. If the decline continues at historical rates, over the next 10 years an additional decline of ~300 BPD of production from Alaska and California will occur which is near the design capacity of the [VET] Project."[223]

G1-78.178

Further, these crudes are more expensive than cost-advantaged crudes from the mid-continent, such as tar sands crudes and Bakken and other North American light crudes. Thus, there is an economic incentive to replace pipeline imports.

As shown in Figure 11, the decline in supply from California (and Alaska) crudes has been replaced by increases in marine imports from foreign sources.

Figure 11. Crude Oil Sources for CA[224]



G1-78.178 cont'd.

[221] DEIR, Appx. F, p. 22.

[222] DEIR, Appx. F, p. F-13/24.Carson was formerly owned by BP, a large Alaska North Slope crude producer.

[223] Sworn Pre-Filed Testimony of Brad Roach, In the Matter of Application No. 2013-01, Tesoro Savage, LLC Tesoro Savage Distribution Terminal, Before the State of Washington Energy Facility Site Evaluation Council, Case No. 15-001, May 13, 2015, attached as Exhibit 23, pp. 15-16. Regarding decline in California and Alaska crude, see also Figure 11 in this Comment; DEIR, Appx. F, p. F-17 and Figure 5; California Energy Commission (CEC) , Margaret Sheridan, California Crude Oil Production and Imports, April 2006, Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF; and Gordon Schremp, California Energy Commission (CEC) , Crude Oil Overview & Changing Trends, Presentation at IEPR Commissioner Workshop – Trends in Crude Oil Market and Transportation, July 20, 2015, pp. 7-10, 16-17; Available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205401_20150720T084540_Crued_Oil_Overview__Changing_Trends.pptx.

[224] Schremp CEC, 2015, p. 10.

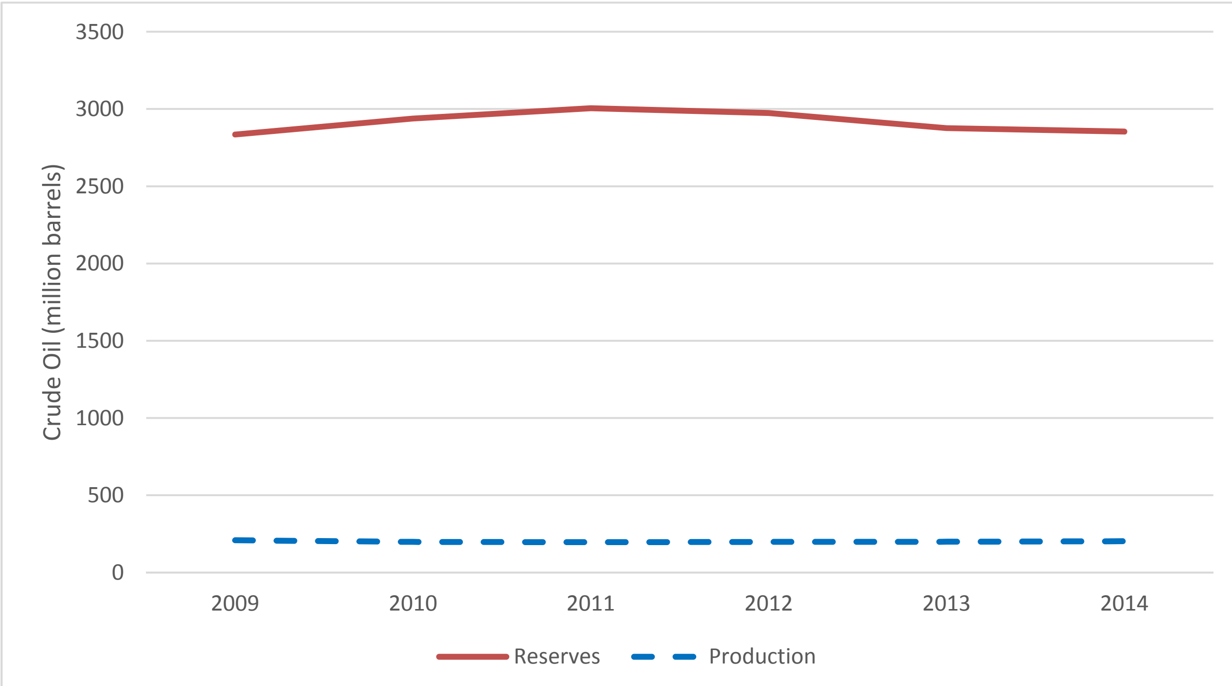
Response G1-78.178

The comment quotes Tesoro testimony for the Vancouver Energy Project as one source of evidence that the production of California crude oil is declining. California crude oil production has declined over the last ten years; however, it has also stabilized in recent years (see Response G1-78.186). As shown in comment Figure 11, both California and ANS production have stabilized in recent years (2010 to present). Although the decline may have been expected to continue, California and ANS crude oil production has not continued to decline. Therefore, there is no foreseeable need to replace California and ANS crude oils (ANS already is delivered by marine vessels) and there is no foreseeable increase in marine vessel deliveries from the potential replacement of pipeline deliveries.

Expert analysis demonstrates that California remains the 4th highest source of crude oil in the U.S.[187] Due to new discoveries, California crude oil reserves have remained steady, and

[187] See Five States and the Gulf of Mexico Produce More than 80% of U.S. Crude Oil, March 31, 2014; Today in Energy, U. S. Energy Information Administration; found at http://www.eia.gov/todayinenergy/detail.php?id=15631#.

production is steady. There is no evidence that crude oil production in California will decline in the near future.[188] In fact, due to the increase in supply of crude oil by Organization of Petroleum Exporting Countries (OPEC) and other suppliers[189], the price of crude oil has dropped considerably. As a result, some U.S. crude oil production[190], including much of the Bakken region oil production, has declined[191], while California crude oil production has remained steady. Further, reserves of California crude oil are relatively constant as shown in Figure 78.178-1, because new reserves are discovered and proven at approximately the same rate as production.



Source: EIA https://www.eia.gov/dnav/pet/pet_crd_pres_dcu_SCA_a.htm

Figure 78.178-1

California Crude Oil Production and Reserves
2009 – 2014

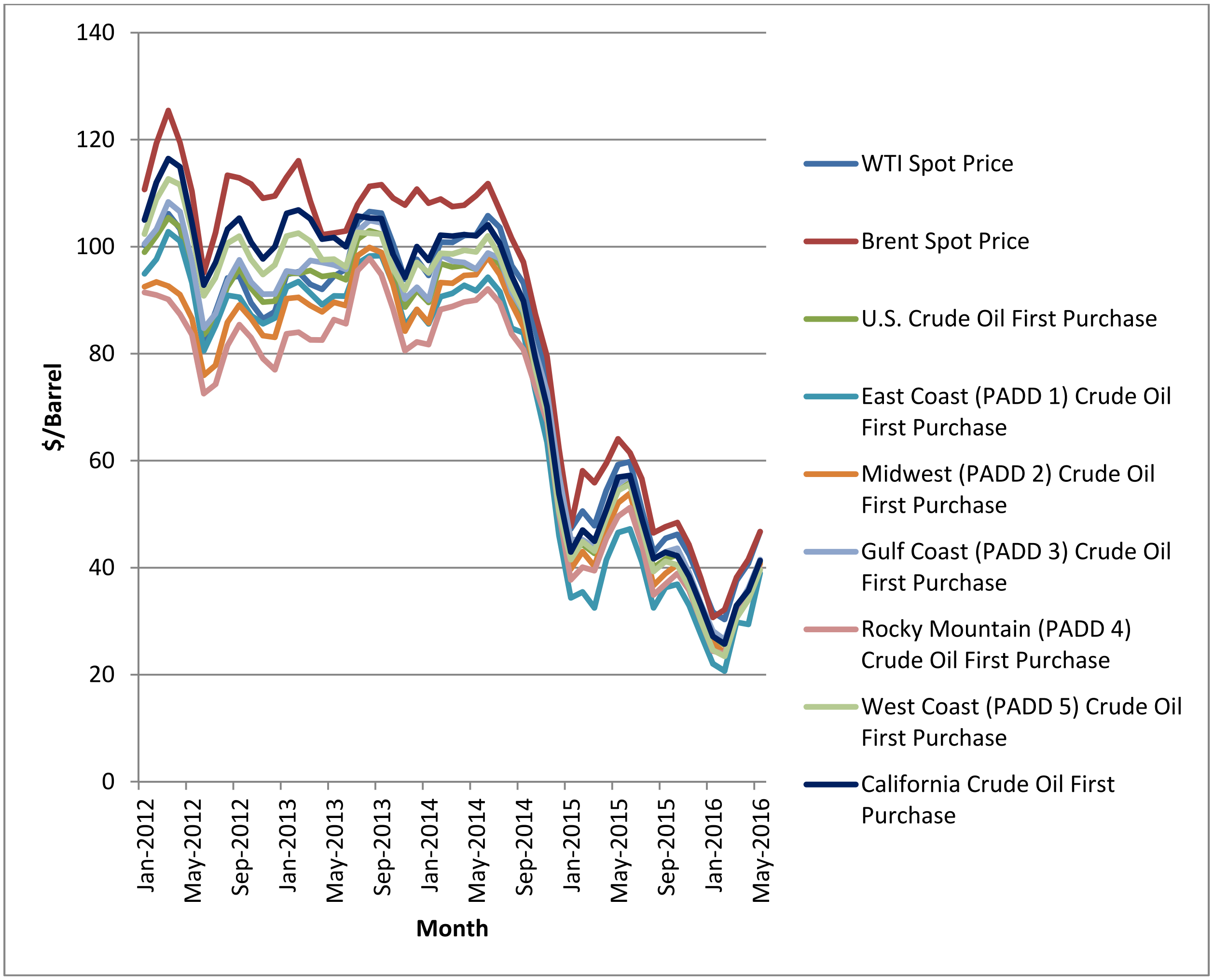
[188] See Crude Oil Proved Reserves, Reserves Changes, and Production, California, U. S. Energy Information Administration; available at http://www.eia.gov/dnav/pet/PET_CRD_PRES_DCU_SCA_A.htm, and http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RCRR01SCA_1&f=A showing California oil reserves in 2009 at 2,835 million barrels with increases in 2010 and 2011, and again in 2014 at 2,854 million barrels.

[189] See U.S. Crude Oil Imports Increase During First Half of 2016, the First Increase Since 2010; October 21, 2016, Today in Energy, U. S. Energy Information Administration, available at http://www.eia.gov/todayinenergy/detail.php?id=28452.

[190] See U.S. Oil Production Continues to Decline, and is now Below its Year-Ago Level, March 9, 2016, Today in Energy, U.S. Energy Information Administration (EIA), available at http://www.eia.gov/todayinenergy/detail.php?id=25292.

[191] See Crude Oil Production, North Dakota Field Production of Crude Oil, U. S. Energy Information Administration, available http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPND2&f=M.

As shown in Figure 78.178-2, California crude oil is competitively priced with other crude oils, such that it is attractive for local refiners to purchase. Therefore, contrary to the comment, there is no economic incentive to replace pipeline imports.



Source: EIA data for First Purchase Prices available at http://www.eia.gov/dnav/pet/pet_pri_dfp1_k_m.htm and Spot Prices available at https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm

Figure 78.178-2

Historic First Purchase and Spot Market Crude Oil Prices (2012-2016)

As explained in Master Response 4, crude oils need to be blended to fit within the physical and permitted constraints of the Refinery in order to be used as feed, so there is no impact on emissions from the processing of crude oil compared to baseline conditions. The proposed project does not include any modifications to the Refinery that will allow a change in the crude oil blend that can be processed at the Refinery. As explained Response G1-78.109 and G1-78.122, potential impacts of storing additional crude oil in the new and replacement crude oil storage tanks have been fully analyzed in the DEIR using worst-case crude oil properties.

Comment G1-78.179

Third, the marine deliveries at both terminals could routinely include crude oils that have much higher vapor pressures than those delivered in the baseline, thus increasing tank VOC emissions relative to the baseline. All of the new crude storage tanks were assumed to have a RVP of 10.5 psi,[225] corresponding to a true vapor pressure of 11+ psi. This is higher than the permitted vapor pressure of the majority of the existing crude storage tanks at Carson and Wilmington[226] and is consistent with the vapor pressure of light shale crudes such as Bakken. These lighter crudes have not been refined in significant quantities at the Wilmington or Carson Operations.

[225] DEIR, Appx. B-3, Attachment B, p. B-3-128 (6 new 500,000 bbl Carson tanks) and p. B-3-189 (3 new Wilmington tanks).

[226] Title V Permits for Wilmington (Facility ID 800436) and Carson (Facility ID 174655).

G1-78.179

Response G1-78.179

In Table 4.2-4 of the DEIR, the increase in VOC emissions from the proposed project crude oil storage tanks was based on crude oil vapor pressure approaching the maximum allowable true vapor pressure limit in SCAQMD Rule 463 of 11 psia. As explained in Response G1.78-122, this analysis presents the most conservative (highest, worst-case) estimates for emissions associated with crude oil delivery.

The selection of this allowable permit limit does not mean that any or all of the storage tanks will hold crude oils with the maximum permitted vapor pressure or will store them for a greater amount of time. Instead, it is common to establish permit limits at the regulatory limit, so as to ensure operating flexibility (e.g., if a storage tank that typically stores light crude oil with a high vapor pressure is to be removed from service for inspection, an alternate storage tank must be used to store the light crude oil). Therefore, permitting the new and replacement storage tanks with limits based on the impacts analyzed in the DEIR provides the flexibility needed to import a variety of crude oils. It should be noted that Tesoro already purchases, stores, and processes Bakken and other lighter crude oils with an RVP of up to 11 psia. The existing storage tanks receiving crude oil have vapor pressure limits that will continue to be adhered to with or without the proposed project. Therefore, there will be no change in emissions from existing storage tanks.

Comment G1-78.180

Fourth, increased ship unloading efficiency does not exclude the possibility of unloading a greater proportion of bigger ships, as compared to baseline operations, or even unloading ships on more days. Simply put, if ships can be unloaded faster, more and/or larger ships can be unloaded, increasing ship emissions.

G1-78.180

Emissions would increase if the number of ship calls increased relative to the baseline or if the mix of Aframax/Panamax changed to favor larger ships. These scenarios were not discussed in the DEIR nor does the DEIR include enforceable conditions that would prevent these outcomes. Instead, the DEIR presents emissions per thousand barrels delivered for Wilmington, assuming the same type of ship and same number of ships in both the baseline and post Project. However, the change in marine vessel emissions due to the Project should be estimated as the difference between pre-project (baseline) and post-project (future) emissions, as follows:

Increase in Ship Emissions = Post-Project Emissions – Pre-Project Emissions (1)

This calculation requires information on the number and type of marine vessels calling in the baseline (2012-2013) and the number and type calling after the Project is fully operational. The DEIR does not contain this information, does not make this calculation. Thus, the DEIR fails as an informational document.

G1-78.180 cont'd.

Response G1-78.180

At the Long Beach Marine Terminal, which is limited to smaller marine vessels (i.e., Panamax and Aframax marine vessels) and at the Carson Crude Terminal, which already receives the largest marine vessels of which it is capable of unloading (i.e., Very Large Crude Carrier (VLCC)), the proposed project will allow marine vessels to unload faster and more efficiently. The proposed project will also create more storage capacity.

The proposed project will not increase capacity of the Refinery other than the 6,000 bbl/day (2.2 million bbl/yr) analyzed in the DEIR. Therefore, the amount of total crude oil delivered to the Refinery, with or without the proposed project, is limited by the refining capacity of the Refinery and not activities related to receipt and storage of crude oil. An analogy is to consider one's personal shopping; if you purchase a gallon as opposed to a quart of milk, you will reduce the number of trips needed to purchase milk from the market. Unless something else changes in your consumption pattern, the amount of milk you purchase and consume will remain unchanged.

Additionally, the data presented in Table 4.2-11 of the DEIR shows that per 1,000 bbl unloaded a larger ship (Aframax) has less emissions than a smaller ship (Panamax). Therefore, should deliveries come in larger marine vessels as the comment suggests, the emission per 1,000 bbl unloaded would decrease and, to deliver the same volume of crude oil, fewer marine vessels would be needed. The analysis in the DEIR conservatively assumes no change in vessel size so the emission reductions associated with a potential migration to larger ship was not considered in the analysis. See Master Response 6 for the discussion explaining that the crude oil processing capacity for the Refinery will not change beyond the 6,000 bbl/day analyzed in the DEIR.

The proposed project impacts were adequately assessed in the DEIR without the need to perform the calculation described in the comment. The vessel sizes received at the Long Beach Terminal are restricted to those currently received (i.e., Panamax and Aframax) due to configuration of the Berths (see page 4-26 of the DEIR). Therefore, no change in the size of the marine vessels delivering crude oil can occur.

The type/size and number of marine vessels that will visit post-project is independent of the 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. Vessel transiting and maneuvering emission rates are higher than hoteling emissions, and the transit time to the berth is approximately 13 hours. Therefore, the peak day consists of 13 hours of transit emissions and 11 hours of hoteling. The peak day emissions for the marine vessel will not change as a result of the proposed project since both the pre- and post-project scenarios require the same amount of transit, maneuvering, and a portion of hoteling.

The extra storage capacity at the Carson Crude Terminal will improve efficiency. Improved offloading speed and additional storage capacity at the Wilmington Operations will allow marine vessels to unload the whole payload faster, reducing time spent in the Port and overall delivery time. As explained in Master Response 6 and Response G1-78.176, reduction in anchorage and delivery time reduces demurrage charges and will generate fewer emissions from marine vessel visits to the Port.

The calculation of the pre- and post-project emissions to determine the proposed project impact requires that the annual post-project delivery fleet is known. As shown in Table 78.177-1, there is variability in the number and type of marine vessels from year to year. Thus, that calculation methodology is not feasible[192], nor is it required. A more accurate assessment of the proposed project impacts is best calculated using the incremental change of emissions by vessel type. Both the additional crude oil expected to be delivered and the reduction in hoteling time from the improved offloading rate define and fully disclose the emission changes from the proposed project. Therefore, the analysis presented on pages 4-26 through 4-29 of the DEIR is based on the annual incremental change in the volume of crude oil to be delivered and the reduction in hoteling time and presents the emissions reductions based on unloading the additional 2.2 million bbl/yr of crude oil from either a Panamax or Aframax vessel, both of which will produce fewer emissions than under current conditions. The DEIR did not take credit for reductions in anchorage and hoteling emissions because the extent of the reductions cannot be accurately quantified without knowing the mix of marine vessels calling. Therefore, the CEQA significance determination in Table 4.2-4 represents a "worst-case" analysis of the proposed project because emissions reductions would further reduce the impacts of the proposed project.

[192] "[T]he CEQA Guidelines require an EIR to provide sufficient information in light of what is reasonably feasible." *Center for Biological Diversity v. Dept. of Fish & Wildlife* (2015) 234 Cal.App.4th 214, 234.

Comment G1-78.181

It is entirely possible, especially in the absence of any enforceable conditions of approval on marine deliveries, that the Project would increase marine deliveries, increasing emissions of VOC, NOx, CO, PM10, and PM2.5. The DEIR must be modified to include clearly stated and enforceable provisions to prevent any increase in marine emissions from increases in the amount of crude oil delivered to the Carson and Wilmington marine terminals or the types of ship used to make the deliveries. These conditions should include:

- a clearly stated and enforceable import cap on marine deliveries of crude oil;
- requirements to test, record, and report to the SCAQMD the RVP and vapor molecular weight of all crude oil delivered by ship, rail, and pipeline;
- source testing of representative ship emissions; and
- publicly available reporting of daily deliveries.

Absent such conditions to assure no increase in marine emissions, the DEIR must estimate the potential increase in emissions from increased marine deliveries to supply the Los Angeles Refinery and mitigate the significant impacts.

G1-78.181

Response G1-78.181

The comment suggests a number of permit conditions to be added to marine terminal permits. However, the proposed project makes no modifications at the marine terminals other than the analyzed storage tank modifications. Therefore, no permit modifications are required for the marine terminals to implement the proposed project and, as such, no permit conditions are affected by the proposed project. The marine terminals have existing SCAQMD permits and comply with the conditions set forth in those permits. Compliance with the permits is expected to occur with or without the proposed project.

CEQA calls for the identification of mitigation measures in the EIR when a proposed project is determined to have a significant effect on an environmental impact area (CEQA Guidelines § 15126.4(a)(3)). The DEIR determined that the proposed project will reduce marine vessel emissions and no significant adverse operational air quality impacts are expected from the proposed project, as a whole. Therefore, no mitigation is required. Accordingly, there is no basis in CEQA for the suggested operational emissions mitigation measures. The increase in marine deliveries associated with the proposed project is limited to the 6,000 bbl/day (2.2 million bbl/yr) that was analyzed in the DEIR (see pages 4-26 through 4-29). As explained in Response G1-78.180, the proposed project will improve efficiency associated with marine deliveries of crude oil, thus reducing emissions.

Comment G1-78.182

Further, as discussed in Comments II.B.4 and III.A, Tesoro Logistics is planning to expand the capacity of its terminals to accommodate other customers. This expansion, facilitated by the Project, should be evaluated as part of the Project and/or as a cumulative project. To the extent that the expansion relies on tanks and other facilities installed under the Integration Project, the increase in emissions from this expansion should be included in the Project's emission increases. Mitigation must be specified to reduce these emissions to the extent feasible.[227]

G1-78.182

G1-78.182 cont'd.

[227] As discussed elsewhere, Tesoro Logistics will provide logistics to third parties (other refineries), not just for Tesoro. So marine unloading, crude transfers, and perhaps also storage could increase for multiple reasons, with associated increases in emissions. This could be due to the Tesoro Los Angeles Refinery running more crude and/or shifting to crude by marine vessel vs. pipeline. But there could also be an increase in emissions as more crude is supplied other refineries, using the infrastructure installed as part of the Integration Project, e.g., the significant increase in storage.

Response G1-78.182

Response G1-78.143 addresses claims regarding marine terminal expansions. As explained in detail in Response G1-78.143, the comment is incorrect and refers to corporate statements regarding expansion of product distribution terminals in order to reduce reliance of and cost of using third-party terminals for product distribution. The expansion of the product distribution terminals is not in any way associated with the proposed project. The proposed project's storage tanks will store crude oil for use at the Refinery, not for immediate transfer to Tesoro Logistics' distribution terminals or third parties. As described in Response G1-78.127, the proposed project is designed to maintain the overall production volume of transportation fuels. Therefore, the proposed project does not require any additional product distribution facilities.

Comment G1-78.183

A. Increase in Marine Vessel Emissions at Wilmington Are Significant

The DEIR estimated the change in marine vessel emissions at only Wilmington using a calculation that compares pre- and post-project emissions for two cases: (1) a single Panamax vessel calling in both the baseline and post-project periods with different unloading rates and (2) a single Aframax vessel calling in both the baseline and post-project with different unloading rates. In other words, the DEIR assumes the same number of and size of vessels in both the baseline and post-Project conditions for the same number of vessel calls -- only one. Thus, the DEIR only evaluates the impact of a change in the unloading rate on emissions, ignoring the fact that the Project debottlenecks terminal throughput. This results in a decrease in emissions because the Project will increase the unloading rate by increasing connecting pipeline diameters and increasing storage. However, this is wrong for five reasons.

First, it fails to account for the actual number of marine vessel calls in the baseline compared to the post-project period. As shown in Exhibit 31, no Aframax vessels called at many of the berths in the baseline.

G1-78.183

Response G1-78.183

The SCAQMD's significance thresholds are peak day thresholds. As explained on page 4-27 of the DEIR, peak daily emissions for marine deliveries occur when the marine vessel is transiting the harbor (i.e., arriving or departing). Since peak day emissions do not change, the analysis of marine vessel emissions is limited to annual changes in marine deliveries.

As noted in Response G1-78.177, the vessel calculation presented in the DEIR shows that a post-project Panamax delivery would emit fewer emissions than a current Panamax delivery due to a reduction in hoteling emissions from offloading the marine vessel more quickly. The calculations in the DEIR also show that deliveries on Aframax vessels emit fewer emissions compared to a Panamax vessel on per barrel basis. It is important to use the per barrel basis when discussing annual emissions, as opposed to a per-vessel basis, because the crude oil in the vessel is the commodity, and not the vessel itself. The comparison on a per barrel basis provides a consistent tool for evaluating both before and after implementing the proposed project and from one vessel size to another.

The only increase in marine vessel emissions associated with the proposed project will result from additional deliveries to accommodate the increased crude oil capacity of up to 6,000 bbl/day (approximately 2.2 million bbl/yr) (see DEIR pages 4-26 through 4-29). Accordingly, the calculations presented in the DEIR also include the incremental increase of 2.2 million bbl/yr of crude oil deliveries over baseline. Therefore, as shown in Table 4.2-11, of the DEIR, any combination of vessels in the post-project will be an emission benefit over baseline deliveries even with an additional 2.2 million bbl/yr of crude oil. The comment asserts the project will debottleneck the terminal capacity without providing evidence or context to support the claim.

The comment claims no Aframax vessels visited the berth during the baseline year. This is incorrect as explained in Response G1-78.177.

Comment G1-78.184

Second, it fails to account for the mix of Aframax, Panamax, and possibly other sized vessels calling in the baseline compared to the post-project period. The DEIR asserts that the largest vessel that can call at its terminals is an Aframax (720,000 bbl).[223] G1-78.184

[228] DEIR, p. 4-26.

Response G1-78.184

It is important to note that the SCAQMD's CEQA significance thresholds are based on a peak day and not annual activity. As previously stated in Response G1-78.183, the important metric is "pounds per barrel delivered" by vessel type and not "pounds per vessel visit" when discussing annual emissions. As shown in Table 4.2-9 of the DEIR, Aframax vessels are environmentally beneficial when compared to Panamax vessels, but after the project completion, both provide emissions benefits when compared to current activities.

As explained in the DEIR, the Wilmington Operations (the only part of the Refinery that will experience the increased unloading rate and crude oil processing capability) cannot receive crude oil from marine vessels larger than an Aframax due to the location and water depth at the Long Beach Marine Terminal (see page 4-26 of the DEIR.) Therefore, the analyzed vessels were appropriately selected and the particular Panamax-Aframax fleet mix is inconsequential because any combination would provide an emissions benefit over baseline emissions. This is because any Panamax visit will have fewer emissions than a current Panamax visit and the same is true for Aframax. And one Aframax visit has fewer emissions per barrel than one Panamax visit. Finally, total barrels delivered do not increase (except for the 6,000 bbl/day (2.2 million bbl/yr) that was analyzed in the DEIR (see pages 4-26 through 4-29)).

This project will not have any influence on the world-wide fleet of marine vessels. Changes in marine vessels, if any, are independent of this proposed project and not foreseeable at this time. The DEIR did not take credit for reductions in anchorage and hoteling emissions because the extent of the reductions cannot be accurately quantified without knowing the mix of marine vessels calling. Therefore, the CEQA significance determination in Table 4.2-4 represents a "worst-case" analysis of the proposed project because emissions reductions would reduce the impacts of the proposed project.

Additionally, since vessel transiting and maneuvering to the berth requires approximately 13 hours, the remainder of the peak day consists of 11 hours of hoteling. The post-project hoteling time to unload 320,000 bbl is expected to be approximately 24 hours. Therefore, the first 11 hours of unloading would occur on the peak day. The peak day emissions for the marine vessel will not change as a result of the proposed project since both the pre- and post-project scenarios require the same amount of transit, maneuvering, and a portion of hoteling.

As described on page 4-26 of the DEIR, the Long Beach Marine Terminal can only receive two sizes of marine vessels, Panamax and Aframax. Additionally, as explained in Response G1-78.185, Marine Terminal T-1 can accommodate larger marine vessels (i.e., Very Large Crude Carrier (VLCC, which holds 1.5 to 2.0 million bbl/vessel)). The proposed project does not propose modifications at the marine terminals. Therefore, only the vessel sizes currently received at the terminals could continue to be received at the terminals.

Comment G1-78.185

Third, it fails to account for the fact that more much larger marine vessels may call, which would have higher emissions. The Tesoro Logistics Form 10-K indicates that one of the marine terminals that services the Los Angeles Refinery is capable of handling a two million barrel capacity very large crude carrier.[229] G1-78.185

[229] DEIR, pp. 2-23/27 and Fig. 2-9; 2015 Tesoro Logistics Form 10-K, p. 8-9.

Response G1-78.185

The comment is the third point under the heading "Increase in Marine Vessel Emissions at Wilmington are Significant". However, the comment discusses larger marine vessels that are only capable of being offloaded at Marine Terminal 1 that serves the Carson Operations. The Long Beach Marine Terminal is not capable of accommodating larger marine vessels than it currently manages and the proposed project does not include modifications to the Long Beach Marine Terminal to allow this.

As described in Master Response 6 and Response G1-78.176, the objective of the additional crude oil storage at the Carson Operations is to more efficiently unload the VLCC marine vessels that already call on Marine Terminal 1, which will reduce anchorage time, demurrage costs, and the associated emissions. This project will not have any influence on the world-wide fleet of marine vessels. Changes in marine vessels, if any, are independent of the proposed project and not foreseeable at this time. Marine Terminal 1 currently receives VLCC and the Long Beach Marine Terminal and Marine Terminal 2 are limited to vessels no larger than Aframax vessels. Responses G1-78.178, G1-78.186, and G1-78.188 explain that no increase in marine vessel deliveries are expected, with the exception of the additional 6,000 bbl/day crude oil capacity increase analyzed in the DEIR. Contrary to the comment, and as explained in Responses G1-78.183 and G1-78.184, larger marine vessels have fewer emissions per barrel. For this reason, should a shift to larger vessels occur in the future, total annual emissions would still be reduced.

The EIA webpage in comment G1-78.177 also states that the only port capable of receiving the Ultra Large Crude Carrier (ULCC, which holds 2.0 million barrels and greater) vessels is in Louisiana. To receive vessels larger than currently delivering crude oil to the Tesoro Marine Terminals, modifications to the marine terminals would need to occur. No modifications to the marine terminals are proposed as part of the proposed project or have been proposed. Therefore, no vessels larger than the vessels already delivering crude oil will be used to deliver crude oil.

Comment G1-78.186

Fourth, it fails to account for the increase in marine vessel calls required to replace any decline in pipeline imports (supply from California crudes). G1-78.186

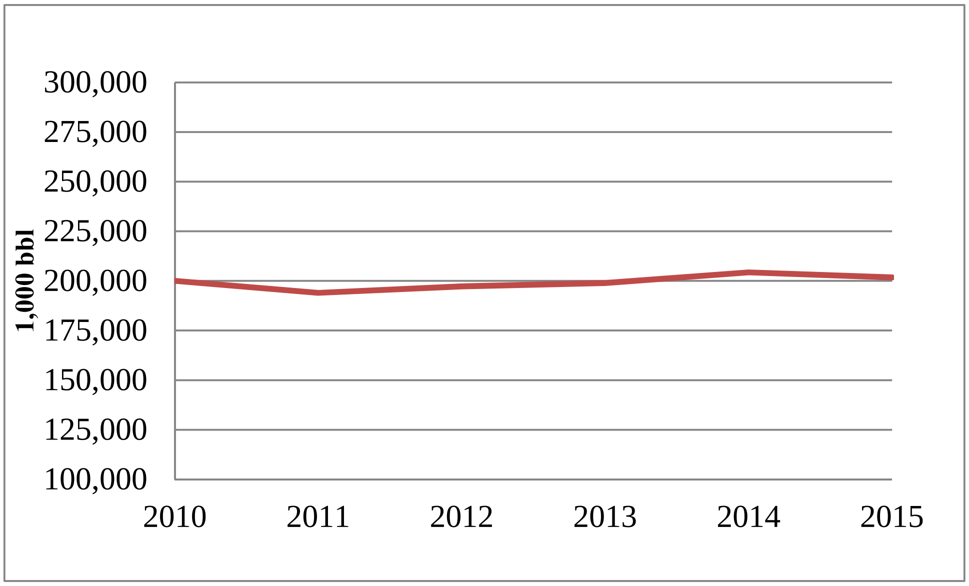
Response G1-78.186

Of the crude oil currently processed by the Refinery, between ten and 20 percent is delivered by pipeline. The comment provides no evidence to support the claim that a decline in crude oil delivered by pipeline would occur as a result of the proposed project.[193] Data available from the EIA shows that California crude oil production has declined historically, but it has remained

[193] CEQA Guidelines § 15204(c): "Reviewers should explain the basis for their comments, and should submit data or references offering facts, reasonable assumptions based on facts, or expert opinion supported by facts in support of their comments."

relatively constant for the past six years (see Figure 78.186-1). There is no evidence to suggest a decline in California crude oil production in the foreseeable future (see Response G1-78.178).

The proposed project has no impact on the supply of California crude oils. Any decline in the availability of California crude oil would occur with or without the proposed project and is independent of the proposed project. Therefore, no analysis of the supply of California crude oils is necessary as part of the proposed project; and, as explained in Response G1-78.178, no increase in marine vessel deliveries are expected, with the exception of the additional 6,000 bbl/day crude oil capacity increase analyzed in the DEIR.



Source: https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

Figure 78.186-1

California Crude Oil Production 2010-2015

Comment G1-78.187

Fifth, it fails to account for emissions from the marine vessels themselves, to the extent that there is an increase in marine traffic.

The DEIR calculated the change in marine vessel emissions at Wilmington assuming the Project would: (1) decrease emissions from the increased offloading rate and (2) increase emissions from a 6,000 bbl/day increase in crude throughput.[230] The net effect of these two factors according to the DEIR is a reduction in marine vessel emissions.[231]

The emissions from marine vessel unloading are presented in pounds per year per 1,000 barrels of crude oil unloaded (lb/yr/1,000 bbl unloaded) in DEIR Table 4.2-11 for two types of vessels: (1) Panamax with a capacity of 400,000 bbl and (2) Aframax with a capacity of 720,000 bbl.[232] These calculations suggest that increasing the unloading rate by a factor of three results in significant reductions in all criteria pollutants, when expressed in units of pounds per year per 1,000 barrels unloaded. See DEIR Table 4.2-11.

However, the net change in emissions when expressed in units of pounds per day, the metric of the significance criteria, depends on the total amount of crude oil received by marine vessel in the baseline compared to post Project. The DEIR did not present this calculation, but rather only assumed a modest 6,000 bbl/day increase, which is the estimated increase in design capacity of the Los Angeles Refinery after the Integration Project is completed. However, as discussed in Comment V.C, this assumed increase in crude throughput is inconsistent with information reported by Tesoro to the U.S. SEC in its most recent 10K report, which indicates the increase could be up to 17,000 bbl/day.

G1-78.187

[230] DEIR, pp. 4-26 to 4-29.

[231] DEIR, Tables 4.2-9 and 4.2-11.

[232] DEIR, pp. 4-26, 4-27, Table 4.2-9.

Response G1-78.187

As previously stated in Response G1-78.176, the impact analysis presented in the DEIR correctly includes an incremental increase of 6,000 bbl/day (2.2 million bbl/yr) over baseline.

The comment states that the daily change in vessel emissions was not presented in the DEIR. Section 4.2.2.2.2 of the FEIR on page 4-27, states:

> *"Thus, the marine vessel emissions associated with auxiliary engines and boilers used while hoteling will be less. All other emissions associated with marine vessel deliveries (e.g., transiting, maneuvering, docking, etc.) are expected to remain the same. Peak day emissions occur when the marine vessel is transiting. Since no change in transiting activities is included in the proposed project, no change to peak day emissions is expected."*

It is important to note that the SCAQMD's CEQA significance thresholds are based on a peak day and not annual activity. As explained in Response G1-78.184, unloading a vessel takes more than 24 hours and the peak day emissions for the marine vessel will not change as a result of the proposed project, since both the pre- and post-project scenarios require the same amount of transit, maneuvering, and a portion of hoteling on the peak day.

As explained on pages 4-26 through 4-29 of the DEIR, there is no change in the peak daily emissions from marine vessels as a result of the proposed project. Only annual emissions change and the analysis of the per 1,000 bbl unloaded metric shows a reduction in emissions when comparing deliveries in the same vessel type (e.g., Panamax).

See Master Response 5 that addresses the difference in crude oil capacity listed in the DEIR versus the SEC 10K filing. The Final EIR notes the difference in the current crude oil processing capacity between 363,000 bbl/day and 380,000 bbl/day. Moreover, the 380,000 bbl/day is the existing capacity, which has already been achieved. 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.

Comment G1-78.188

The DEIR's marine vessel analysis is very misleading. It fails to acknowledge that the Project facilitates an increase in marine deliveries of far more than the 6,000 bbl/day increase in design throughput due to modifications of refining processes at the combined facility pursuant to the Tesoro Integration Project. It also fails to calculate the change in emissions relative to the baseline, by erroneously assuming the same size ship before and after the Project. The California State Lands Commission (CSLC) data in Exhibit 31 shows that this is clear error. G1-78.188

The Wilmington and Carson Operations have historically received crude oil by pipeline from the San Joaquin Valley and Los Angeles Basin and by ship from the Alaska North Slope and foreign sources.[233] In the baseline, Carson, formerly owned by BP (which is a large Alaska North Slope crude producer), refined crude oil from the Alaska North Slope and foreign sources.[234] Similarly, in the baseline, Wilmington refined crude oil received by pipeline from the San Joaquin Valley and Los Angeles Basin as well as by ship from various unidentified sources. If the pipeline deliveries, which are declining and generally more expensive than other sources, were replaced by marine deliveries (notably from Tesoro's VET), marine emissions would increase compared to the DEIR's estimate. G1-78.188 cont'd.

The DEIR fails to disclose the relative amounts of each crude oil received by pipeline and marine vessel in the baseline and post-Project. The DEIR also fails to disclose that these historically refined crudes are in decline and will be replaced over the lifetime of the Project.[235] The modifications at the Wilmington Marine Terminal not only speeds up unloading. They also facilitate unloading more ships than called at the Terminal in the baseline, thus allowing the integrated refinery to increase its marine imports.

[233] Tesoro, Los Angeles Refinery; Available at: http://tsocorp.com/refining/los-angelescalif/.

[234] BP, BP Completes Sale of Carson Refinery and Southwest US Retail Assets to Tesoro, June 2013; Available at: http://www.bp.com/en/global/corporate/press/press-releases/bp-completes-sale-of-carson-refinery-and-southwest-u-s--retail-a.html.

[235] Pacific L.A. Marine Terminal SEIR/DSEIR, Appendix D3: Southern California Petroleum Market Assessment, May 2008; Available at: https://www.portoflosangeles.org/EIR/PacificLAMarine/SEIR/Appendix_D3_Southern_CA_Petroleum_Market_Assessment.pdf.

Response G1-78.188

As explained in Responses G1-78.178 and G1-78.186, there is no evidence to support the speculative claim that pipeline deliveries are declining and will be replaced by marine vessel deliveries or that California crude oils are not cost competitive.[194] The reference in Footnote 235 of the comment was published in 2008 before California crude oil production leveled off and began trending upwards slightly (see Figure 78.186-1). Therefore, the impacts claimed in the comment are not reasonably foreseeable, expected to occur, or supported by facts.

As described in Master Response 6, the crude oil processing capacity is not increasing over the 6,000 bbl/day analyzed in the DEIR. The proposed project is not designed to change the origin of crude oils as explained in Master Response 4. As shown in Master Response 4 Table G02.4-1, the origin of crude oils routinely changes independently of the proposed project.

The impact analysis in the DEIR included the potential increased crude oil refining capacity that would result from the proposed project (i.e., 6,000 bbl/day or 2.2. million bbl/yr) and assumed that this crude oil would be delivered by marine vessels to the Long Beach Marine Terminal. As described in Response G1-78.177, the marine vessel sizes are limited to those currently received at the Long Beach Marine Terminal, which is demonstrated by the data in Comment Exhibit 31. As explained in Response G1-78.187 and the DEIR (pages 4-26 and 4-27), the peak day emissions from marine vessels are when the vessel is transiting into the harbor and maneuvering to the dock. There will be no change in peak day emissions.

Comment G1-78.189

As explained previously (Comment II.B.4) an increase in Marine Terminal throughput is consistent with public announcements by Tesoro Logistics, the terminal operator. Tesoro Logistics has announced it plans to expand the capacity of its marine terminals.[236] In its May 1, 2014 earnings call, Philip Anderson, President of Tesoro Logistics LP stated:

> "We have two of our terminals are being expanded (sic) to handle additional capacity, and those expansions will come online this summer. And that will allow us to bump up volumes either very late in the second quarter or early in the third quarter."[237]

G1-78.189

Capital Markets further identifying which terminals would be expanded and by how much:

> "Our marine facility down there [referring to Tesoro terminals in Long Beach], 121, which is the large T-Berth[238] in Long Beach, stays pretty full. We have our legacy to Long Beach terminal [Marine Terminal] that is adjacent to our newly acquired, what we call, T-2 in Long Beach. And between T-2 and our legacy Long Beach terminal, we probably have an additional 100,000 plus barrels per day of throughput capacity."[239]

G1-78.189 cont'd.

[194] CEQA Guidelines § 15204(c): "Reviewers should explain the basis for their comments, and should submit data or references offering facts, reasonable assumptions based on facts, or expert opinion supported by facts in support of their comments."

[236] August 2012 Tesoro Logistics Presentation, pp. 12-13, Exhibit 24; 1/9/14 Tesoro Presentation, p. 24, Exhibit 16.

[237] 5/1/14 Q1 2014 Tesoro Logistics Earnings Call Transcript, p. 6, Exhibit 25.

[238] "T-Berth" mistranscribed as "de-berth".

[239] 5/1/14 Q1 2014 Tesoro Logistics Earnings Call Transcript, p. 7, Exhibit 25.

Response G1-78.189

The comment has been raised previously, see Response G1-78.143.

Comment G1-78.190

The 100,000 bbl/day of unused throughput capacity is consistent with similar estimates published elsewhere. This other analysis reported Berths 76-78 [Tesoro legacy Marine Terminal] had 43,000 bbl/day and Berths 84-87 [newly acquired T-2] had 59,000 bbl/day of unused capacity, for a total of 102,000 bbl/day.[240] Thus, with no physical modifications to the Marine Terminals themselves, the Project, by removing a vapor recovery capacity constraint, increasing the diameter of the connecting pipeline, and increasing storage capacity, would allow an increase in currently unused throughput of about 102,000 bbl/day. This unused throughput could be used to replace crude that currently arrives by pipeline. G1-78.190

[240] Pacific L.A. Marine Terminal SEIR/DSEIR, Appx. D1, pp. D1-20/21; ; Available at: https://www.portoflosangeles.org/EIR/PacificLAMarine/SEIR/Appendix_D1_Throughput_Projection_Vessel_Mix_Methodology.pdf; see also LARIC DEIR, pp. 2-25/26/27 for description of marine terminals associated with the Tesoro Los Angeles Refinery.

Response G1-78.190

The unused capacity information presented in the comment accurately reflects current conditions at the Long Beach Marine Terminal and Marine Terminal T-2. However, the vapor recovery constraint is only applicable to Wilmington Operations, which is served by the Long Beach Marine Terminal.

The vapor recovery system has a fixed capacity and consists of a complex system of piping, compressors, and other equipment to manage vapors from multiple storage tanks throughout the Wilmington Operations. The filling rate of fixed roof storage tanks that vent to the vapor recovery system (i.e., the offloading rate from the Long Beach Marine Terminal) is limited by the vapor recovery system capacity to manage the vapors displaced when the storage tank is being filled. The proposed storage tanks are directly controlled with floating roofs meeting BACT requirements. The floating roofs rest on the liquid surface of the crude oil so that there is no vapor space above the liquid surface where vapors would be generated (as there is in the existing fixed roof storage tanks that are vented to the vapor recovery system). Therefore, floating roof storage tanks do not require connection the vapor recovery system.

Additionally, the change in pipeline diameter will occur within the Wilmington Operations boundaries limiting potential impacts to the Wilmington Operations. The potential impacts were analyzed in Chapter 4 of the DEIR including emission impacts associated with the replacement storage tanks at the Wilmington Operations. The proposed project analysis does not conflict with the stated available capacity for the Long Beach Marine Terminal. To the contrary, the DEIR analyzed the impacts of the improved efficiency of unloading crude oil into the proposed replacement storage tanks, which are not constrained by the vapor recovery system at the Wilmington Operations (see pages 4-26 through 4-29 of the DEIR).

The proposed project does not include any modifications to Marine Terminal T-2. Unused throughput capacity associated with Marine Terminal T-2 is not constrained by vapor recovery, such that utilizing the available capacity could occur with or without the proposed project. The proposed project makes no changes to facilitate the use of the available throughput capacity at Marine Terminal T-2.

As explained in Response G1-78.178, pipeline deliveries (i.e., California crude oils) are not expected to decrease in the foreseeable future.

Comment G1-78.191

More modifications are planned to capture additional throughput increases, allowed by the Project's increase in tank and pipeline throughput. In the February 2014 earnings call, the President of Tesoro Logistics, Phillip Anderson, stated: "The remainder of the organic growth is focused primarily in our Southern California assets, where we're expanding a couple of the terminals, and adding additive and blending systems to those terminals to enable some of the higher throughputs that we expect to bring into those terminals over time. Once we have that, we'll determine the right size of pipes and pumps to put in to enable those volumes and finalize an engineering estimate."[241] A project is currently pending at the POLB, the Berths 84-87 Tesoro Facility Improvements project.[242] Thus, the Project facilitates an increase in marine G1-78.191

throughputs consistent with plans to expand the capacity of these terminals. G1-78.191 cont'd.

[241] Tesoro Logistics Q4 2013 Earnings Call Transcript, February 6, 2014, Exhibit 3.

[242] G.J. Cardamonte, Port of Long Beach 2012 Capital Program Update, September 2012, pdf 37 ("Berths 84-87 Tesoro Facility Improvements"), Available at: http://www.cmaasc.org/pdfs/092012_portoflb.pdf. See also: http://www.polb.com/civica/filebank/blobdload.asp?BlobID=11974.

Response G1-78.191

See Responses G1-78.143 and G1-78.144 that address the corporate statements that are referenced in the comment. The product terminal capacity increases discussed in the corporate statements are intended to reduce reliance on and costs of using third-party terminals for product distribution and are not in any way associated with the proposed project

Comment G1-78.192

Further, my research indicates that in the baseline, Tesoro's West Coast refineries refined about 19% foreign heavy crudes, 30% foreign light crudes, 19% Alaska North Slope (ANS), 17% California heavy crudes, and 15% North American crudes.[243] My review of the DEIR and other publicly available information indicate that one purpose of the Project is to allow the Los Angeles Refinery to replace supply from ANS and California crudes and foreign crude oil imports (which is declining and/or more expensive)[244] with cost-advantaged North American crude oils delivered by marine vessel from the VET. G1-78.192

[243] Tesoro, Transformation through Distinctive Performance, Simmons Energy Conference, February 27, 2014, p. 18, Exhibit 26. Elsewhere, it is reported that the Wilmington Refinery primarily runs heavy crude produced in California and imported from abroad, while the Carson Refinery runs crude oil from Alaska's North Slope, the Middle East, and West Africa. Further, the presentation, Tesoro Transformation through Distinctive Performance, Exhibit 26, p. 13, indicates that the Tesoro Los Angeles refinery was then running 15% California heavy crude.

[244] California Energy Almanac, Crude Oil Supply Sources to California Refineries, Available at: http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.

Response G1-78.192

The issues raised in the comment have been raised previously, see Responses G1-78.135, G1-78.136, G1-78.150, G1-78.151, and G1-78.178. As an existing facility that receives crude oil from around the world (see Master Response 4 Table 2.4-1) with varying crude oil properties, the Refinery already receives and processes crude oil in its crude oil blend and the proposed project does not change the types of crude oils processed.

Comment G1-78.193

More marine deliveries will be required to continue to support the Wilmington Operations in the face of these declining crude sources. It is well known that the California crudes delivered to both Wilmington and Carson by pipeline are in decline. Thus, to continue operating at or near capacity, the integrated refinery must import increased amounts of crude oil to replace declining pipeline supplies. The most likely source of replacement crude is marine deliveries from Tesoro's proposed marine terminal in Vancouver, Washington (VET). See Comment II. Tesoro's Los Angeles Refinery (the integrated Carson and Wilmington Operations) will receive from 50,000 bbl/day up to 300,000 bbl/day of crude oil by marine vessel from the Vancouver Terminal.[245] G1-78.193

I estimated the increase in criteria pollutant emissions from increased marine deliveries to the Wilmington Marine Terminal using the lower end of the project VET export range, or post-Project marine deliveries of 50,000 bbl/day, assuming these would

replace pipeline imports, which comprise up to 65,000 bbl/day.[246] As the design throughput of the Los Angeles Refinery is 380,000 bbl/day[247] and about 17% arrived by pipeline from California sources in the baseline, up to about 65,000 bbl/day of pipeline imports could be replaced by marine deliveries. I also used the DEIR's emission factors for both Panamax and Aframax ships (Table 4.2-11) and the DEIR's baseline marine deliveries of 30,000 bbl/day.[248] G1-78.193 cont'd.

[245] Tesoro's proposed marine terminal in Vancouver has a design capacity of 360,000 bbl/day, but achievable throughput is expected to average 300,000 bbl/day. Tesoro has committed to take at least 60,000 bbl/day, but could take up to the full output of the VET. Some crude from VET could go to Tesoro refineries in Martinez (California), Anacortes (Washington), and Kenai (Alaska), but the Los Angeles refinery is the largest and most likely destination. Likewise, Tesoro could handle crude at VET and its Los Angeles marine terminals that would then be supplied to other Los Angeles area refineries. See: Tesoro Analyst and Investor Presentation, December 9, 2014, pp. 13-14, Exhibit 15, and Ian Goodman Direct Testimony, Washington Energy Facility Siting Evaluation Council, Case No. 15-001, May 12, 2016, Exhibit 27, especially pp. 20-24.

[246] Amount of crude oil delivered by pipeline = Los Angeles Refinery capacity as reported in Tesoro 2015 10K report x percent of total supply from California = 280,000 x 0.17 = 64,600 bbl/day.

[247] Tesoro, Los Angeles Refinery; Available at: http://tsocorp.com/refining/los-angelescalif/.

[248] Crude oil deliveries by marine vessel to the Marine Terminal for the Wilmington Operations in the baseline (2012, 2013) are 10.940 million barrels or (10,940,000/365) = 29,973 bbl/day. DEIR, p. 4-28 and Table 4.2-10.

Response G1-78.193

See Responses G1-78.178 and G1-78.186 that address the claim in the comment regarding the decline and cost of California crude oil. See Master Responses 4 and 8 that address the comment about the Refinery's crude oil slate and the Vancouver Energy Project.

Comment G1-78.194

My calculations, included in Exhibit 28 and summarized below in Table 4, show that if marine imports increased by 50,000 bbl/day, for Panamax vessels, the average daily increase in both VOC (84 lb/day) and NOx (2,367 lb/day) emissions exceed the CEQA significance thresholds. For Aframax vessels, the average daily increase in NOx (1,292 lb/day) exceeds the CEQA significance threshold (55 lb/day). Peak daily emission increases could be even higher as future increases in marine deliveries, relative to the baseline, could be even higher.

If future marine deliveries were 65,000 bbl/day higher than in the baseline, replacing 100% of pipeline imports, the increase in emission of VOC (84 lb/day) and NOx (2,367 lb/day) would exceed the CEQA significance thresholds assuming Panamax vessels. Ex. 28, Tab Panamax, summarized in Table 2. Assuming Aframax vessels, VOC (155 lb/day) and NOx (4,027 lb/day) emissions would exceed CEQA significance thresholds. Ex. 28, Tab Aframax, summarized in Table 2.

G1-78.194

Table 4.
Summary of Increases in Marine Emission Relative to the Baseline

Vessel Type	Deliveries (bbl/day)	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx	PM10	PM2.5
Panamax	50,000	**84**	202	**2367**	-70	3	2
Panamax	65,000	**228**	548	**6279**	58	21	17
Panamax	100,000	**564**	**1357**	**15,407**	**355**	63	52
Aframax	50,000	51	147	**1292**	-128	2	1
Aframax	65,000	**155**	400	**4027**	-21	17	13
Aframax	100,000	**396**	**992**	**10,407**	**227**	52	41
Significance Threshold		55	550	150	150	150	55

Finally, as shown in Table 4, if marine imports increased by 100,000 bbl/day, to support other terminal customers, using changes to the terminals made by the Project, the increase in VOC, CO, and NOx emissions would exceed CEQA significance thresholds for both Panamax and Aframax vessels.

G1-78.194 cont'd.

Response G1-78.194

First, as explained in Responses G1-78.178, G1-78.186, and G1-78.188, the suggestion in the comment that the proposed project will replace pipeline deliveries with marine vessel deliveries (facilitating a shift of up to 65,000 bbl/day) is unsupported by evidence. The claim that the proposed project might not only replace pipeline deliveries to the Refinery with marine vessel deliveries but could also import additional barrels of crude oil to support other terminal customers is also unsupported and speculative. No evidence is offered in support of these statements. Therefore, the calculations summarized in the comment Table 4 are not based on facts.

Regardless, the claim in the comment that the daily emissions from marine vessel deliveries will be significant because more crude oil can be offloaded in a day is incorrect. The relevant analysis is based on a peak day not an average day because the significance threshold is a peak day threshold. As explained in Response G1-78.184, the peak daily emissions from marine vessels are not affected by the amount of product offloaded in a day because the peak day emissions occur on a day where both transiting and unloading occur, not a day where just unloading occurred. Therefore, the DEIR analyzed the worst-case impact with respect to emissions from marine vessels. Additionally, the number of available berths to receive marine vessels is not changing and the maximum number of vessels has been concurrently located at the berths during the baseline period, so the peak number of marine vessels per day cannot and will not change.

Based on the applicable threshold of significance, the DEIR appropriately analyzed the emissions based on hours of transit, maneuvering, and hoteling. As explained in Response G1-78.184, since unloading a vessel takes more than 24 hours, the peak day emissions for each marine vessel will not change as a result of the proposed project since both the pre- and post-project scenarios require the same amount of transit, maneuvering, and a portion of hoteling. As explained in the DEIR (see pages 4-26 through 4-29) and Master Response 6, emission reductions associated with marine vessels are expected from implementing the proposed project. Therefore, the CEQA significance determination in Table 4.2-4 represents a "worst-case" analysis of the proposed project because emission reductions would lessen the impacts of the proposed project.

Comment G1-78.195

The DEIR claims that there would be large emission decreases in all criteria pollutants due to the shutdown of the Wilmington FCCU and estimates the resulting net change in emissions in DEIR Table 4.2-4. Even assuming, *arguendo*, that the DEIR's emission changes due to the Project are valid (and some are not valid as discussed elsewhere in these Comments), the increase in VOC and NOx emission for Aframax and Panamax vessels remain significant. However, the significant CO impact for the 100,000 bbl/day Aframax case drops from 992 lb/day to 402 lb/day, below the significance threshold of 550 lb/day, due to the large claimed CO emission reductions (-909.62 lb/day)[249] from the shutdown of the FCCU.[250] G1-78.195

[249] DEIR, Table 4.2-4.

[250] Ex. 28, Tab: Panamax, Lines 16, 34, and 52; Tab: Aframax, Lines 16, 34, and 52.

Response G1-78.195

The comment inaccurately claims that the proposed project would have significant peak day VOC and NOx emissions because of marine vessel emissions. As explained in Responses G1-78.184, G1-78.187, and G1-78.194, the increases in marine deliveries described by the comment are not expected to occur and peak daily emissions from marine vessels will not change as a result of the proposed project. Therefore, the CEQA significance determination in the DEIR is correct.

Comment G1-78.196

B. Increase In Marine Vessel Emissions at Carson

At Carson, up to six new 500,000 barrel domed external floating roof crude oil storage tanks and five electrically-driven transfer pumps will be constructed adjacent to the Carson Crude Terminal to increase the crude unloading rate at the Carson Crude Terminal. Piping and instrumentation will be installed within the Carson Crude Terminal to connect these new tanks to existing pipelines to the Carson Operations and Marine Terminal 1.[251] The DEIR asserts these new tanks:

> *"will allow marine vessels to unload crude oil without undue delay, thereby reducing the time vessels are required to wait at anchorage until sufficient tankage is available for vessel discharge. This portion of the project will reduce the amount of time that vessels spend within the port and increase the amount of crude oil that can be unloaded and stored. Decreasing the amount of time the vessels spend within the port and at anchor will substantially reduce annual ship emissions. Storage capacity does not affect Refinery throughput, which is based on processing capabilities as described in Section 2.5.4.1.*[252]

G1-78.196

However, the DEIR fails to disclose the anticipated increase in unloading rate and the baseline crude oil deliveries via marine vessels to the Carson Marine Terminal. The DEIR also fails to present any emission calculations for marine vessels at the Carson Marine Terminal. The DEIR does not contain sufficient information to allow me to estimate these emissions. Thus, the DEIR fails as an informational document.

G1-78.196 cont'd.

[251] DEIR, pp. 1-6/7, 1-16/17, 2-46, 2-48, Figure 2-16; Appx. B-3, Table 1.

[252] DEIR, p. 1-17. See also similar assertions at DEIR pp. 2-4, 2-46, 6-1.

Response G1-78.196

As explained in Response G1-78.176, the proposed project does not include changes to the capacity or unloading rate of crude oil to the Carson Crude Terminal. The five proposed electrically-driven transfer pumps at the Carson Crude Terminal are to allow for tank-to-tank transfers or tank-to-Refinery transfers and are not used for marine vessel-to-tank unloading from Marine Terminal T-1. The proposed crude oil storage tanks at the Carson Crude Terminal will allow the marine vessel to offload the entire load in one call instead of going to anchor. Marine Terminal T-1 can only berth one marine vessel at a time, which is the current operating condition and the proposed project does not modify this condition. Therefore, there will be no change in peak daily emissions associated with the proposed project, only emission reductions from reduced hoteling while at anchor.

Comment G1-78.197

C. Increase in Marine Vessel Emissions Due to Larger Vessel Calls Post-Project Compared to Baseline

The CSLC marine delivery data (Exhibit 31) show that in the baseline, only LR1 ships (25,000 to 80,000 DWT vessels, typically Panamax) serviced all of the marine terminals but berth 121. No LR2 ships (80,000 to 160,000 DWT vessels, typically Aframax) serviced berths 84, 84A, and 86, and only one LR2 vessel serviced berth 78 in the baseline, with light LR2 traffic at berths B84 and B86. Thus, the Project would facilitate an increase in LR2 ships compared to the baseline, especially at those terminals where no Aframax vessels called in the baseline. The DEIR did not consider this case, but rather assumed vessel calls by the same size vessel in both the baseline and post-Project and only calculated emission changes due to changes in unloading rate. This is inconsistent with the CEQA requirement that emission increase be calculated relative to the baseline. In the case of many of the berths, no Aframax vessels called in the baseline.. G1-78.197

Response G1-78.197

As explained in Response G1-78.177, Panamax and Aframax marine vessels were received at the Long Beach Marine Terminal in 2012 and 2013. At least 57 (36 in 2012 and 21 in 2013) of the marine vessels received must be Aframax (LR2) vessels and some of the LR1 vessels could be Aframax during the baseline period, if they were 80,000 deadweight ton ships. Moreover, Aframax (larger) marine vessels have fewer emissions per 1,000 barrels than Panamax (see DEIR Table 4.2-11). A shift to larger vessels (i.e., from Panamax to Aframax) would reduce emissions because it is more efficient to deliver crude oil in larger vessels.

Comment G1-78.198

The marine vessel emission calculations in Appendix B-5 indicates that unloading an LR2 ship (Aframax) would significantly increase emissions compared to unloading a Panamax ship, as summarized in Table 5. The length of each ship visit is unknown, but conservatively assuming the baseline unloading rate for an Aframax vessel of 5,149 bbl/hr and a load of 720,000 barrels, the entire cargo could be unloaded in 6 days.[253] Rounding this up to 10 days to account for transit and hoteling times, the NOx emissions are highly significant. If more than one Aframax called at ports where none called in the baseline, the increase in emissions would be even higher and could result in exceedances of other significance thresholds. G1-78.198

Table 5.
Increase in Emissions from Aframix Visit
Compared to Panamax Visit.[254]

	Emissions per Ship Visit (lb/visit)				
	VOC	CO	NOx	PM10	SOx
Aframax	457	1111	12,000	63	468
Panamax	351	845	954	45	310
Increase	106	265	11,046	18	158
Significance Threshold (lb/day)	55	550	**55**	150	150
Significant?			**Yes**		

G1-78.198 cont'd.

The EIR must be modified to disclose baseline vessel calls and emissions and marine vessel emissions must be estimated relative to the 2012-2013 baseline. Further, the EIR must be modified to require mitigation for the significant marine vessel NOx emissions as summarized in Tables 4 and 5.

[253] Worst case unloading time for an Aframax vessel = 720,000 bbl/(5,149 bbl/hr * 24 hr/day) = 5.8 days. Unloading rate and Aframax capacity from DEIR, Appendix B-5, p. B-5-10.

[254] Data summarized from DEIR, Appendix B-5.

Response G1-78.198

The comment is based on the unsupported premise that no Aframax vessels visited the Long Beach Marine Terminal during the baseline period. As explained in Response G1-18.177, Aframax vessels were received during the baseline period. More importantly, at the Long Beach Marine Terminal, the proposed project will allow an Aframax vessel to unload more quickly and will reduce hoteling time and the associated emissions. Comment Table 5 compares vessel visit emissions, which occur over more than one day, to the CEQA Significance Thresholds that are daily thresholds. This comparison is invalid.

As explained in Response G1-78.184, a marine vessel is in berth for more than 24 hours. Therefore, only a fraction of the emissions of a vessel visit are emitted in a peak day. Furthermore, as explained in Response G1-78.187, marine vessel activities will not change on the peak day. Therefore, no new marine vessel emissions are expected to occur on the peak day from the proposed project (see DEIR pages 4-26 through 4-29).

Comment G1-78.199

IV. GREENHOUSE GAS EMISSIONS ARE SIGNIFICANT

The DEIR asserts that the Project will result in a decrease of greenhouse gas emissions (GHG) of 66,139 metric tons per year (MT/yr).[255] [Note that Appx. B-3, p. B-3-38 reports 70,321 MT/yr]. However, these calculations do not include the increases in GHG emissions from increased marine vessel calls at the ports, LPG train trips, combustion of increased amounts of LPG, and the GHG emissions from producing and delivering Bakken and/or tar sands crudes from their point of origin to the POLB marine terminals. The DEIR must be revised to include these additional sources and recommend mitigation for any significant impacts.

G1-78.199

[255] DEIR, p. 1-38 and Appendix B-3, Section 5.

Response G1-78.199

Comment G1-78.199 references the Executive Summary but does not mention the more detailed analysis in Chapter 5 of the DEIR. The analysis of the GHG impacts associated with the proposed project is provided in detail in Section 5.2.2 of the FEIR (see pages 5-21 through 5-27). It should be noted that Appendix B-3 includes GHG onsite emissions only, Appendix B-5 includes the mobile source GHG emissions, and Appendix B-1 includes the construction GHG emissions. Therefore, Appendix B-3 should not be solely relied upon for the estimates of total GHG emissions.

As explained in the DEIR on page 4-27, the proposed project has two aspects that will potentially affect marine vessel annual emissions: (1) increasing the offloading rate, and (2) additional deliveries to accommodate the increased crude oil capacity of up to 6,000 bbl/day (2.2 million bbl/year). As shown in DEIR Appendix B-5 on page B-5-9, the net effect of these potential changes is a reduction in criteria pollutants and GHG emissions. The criteria pollutant and corresponding GHG emissions from marine vessels are presented in Appendix B-5 pages B-5-13 and B-5-14. Due to the uncertainty of the combination of vessels (i.e., all Panamax, all Aframax, or a combination of the two types) that would deliver the additional crude oil, no marine vessel emission reductions were included in GHG analysis in Section 5.2.2 or presented in Table 5.2-6. In fact, as analyzed in the DEIR, the proposed project is expected to result in a reduction in marine vessel criteria pollutants and associated GHG emissions (see Appendix B5 page B-5-9). Additional GHG emission reductions associated with the reduction in anchorage events as a result of the improved efficiency of offloading crude oil into the proposed new crude oil storage tanks at the Carson Crude Terminal were also not credited in the GHG emission analysis presented in the DEIR. Therefore, the GHG analysis conservatively underestimates the GHG emission reductions expected from implementing the proposed project.

The potential increase in GHG emissions from LPG train trips is included in the DEIR and shown in Table 5.2-8 (see page 5-26) and includes both offsite and onsite rail emissions, emissions from mobile sources, and construction emissions. It should be noted that there is an error in Table 5.2-7 where the GHG emissions for 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 Appendix B-3 Table 13 on page B-3-37). 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).

The proposed project does not include combustion of LPG. As explained in DEIR 2.7.3.3, additional LPG needed for the proposed project is to be used as feedstock to the Wilmington Operations Alkylation Unit where it is processed and converted into high quality, low RVP gasoline blendstocks.

The transport of Bakken or heavy Canadian crude oil to the Refinery will not increase as a result of the proposed project (see Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9, and Response G1-78.94). Therefore, no increase in GHG emissions would occur from the delivery of Bakken or heavy Canadian crude oil. Any change in the source of crude oil, either with or without implementation of the proposed project, is speculative. However, sourcing crude oil from North America would have less transportation emissions than crude oils currently sourced from foreign origins.

Comment G1-78.200

V. OPERATIONAL EMISSIONS FROM FIRED SOURCES ARE UNDERESTIMATED AND ARE SIGNIFICANT

G1-78.200

The Project includes modifications to many fired sources – heaters, furnaces, and boilers.[256] These modifications generally involve an increase in the permitted firing rate, increased utilization, or new equipment. The Project also includes the shutdown of the Wilmington FCCU. The emissions from many of these sources have been

improperly calculated under CEQA, resulting in significant impacts that were not disclosed in the DEIR.

G1-78.200 cont'd.

[256] DEIR, Table 4.2-4 and Appx.B-23, Table A-1 to A-4.

Response G1-78.200

The comment summarizes the conclusions reached in Section V of the comment letter. The various issues raised in the comment are addressed in subsequent responses as shown in Table 78.200-1.

Table 78.200-1

Topics Raised in Comment and Location of Responses

Topic	Response	
	Master Response Number	Specific Response Number
Heater Startups and Shutdowns		G1-78.201 - G1-78.202
Baseline for Heater Emissions	12	G1-78.203 - G1-78.206, G1-78.209
Flaring Emissions	15	G1-78.207
Emissions Included from Increased Crude Oil Capacity	5, 6	G1-78.208
Wilmington Operations FCCU Shutdown Emissions		G1-78.210 - G1-78.211

Comment G1-78.201

A. Heater Emissions Exclude Startups And Shutdown

The DEIR evaluated the significance of the Project's operational emissions by calculating the change in daily emissions due to the Project, relative to the CEQA baseline in 2012 to 2013:[257]

Increase in Emission = Project Emissions (lb/day) – Baseline Emissions (lb/day)

The resulting emission changes for all Project components in pounds per day (lb/day) were then summed over all components and compared to the SCAQMD's CEQA significance thresholds. This analysis is presented in DEIR Table 4.2-4, which concluded that the Project would not result in any significant changes in emissions. However, this analysis is fundamentally flawed because it failed to include emissions during periods of startup and shutdown of fired sources, estimated to occur for 720 hours per year.[258] G1-78.201

During periods of startup and shutdown, emission control devices, such as selective catalytic reduction (SCR) and low NOx burners, are either not working at all or are only partially working. Further, during these periods, incomplete combustion occurs, which increases emissions of NOx, VOC, and CO. The DEIR explicitly recognizes the impact of startup, shutdown and commissioning on NOx emissions, but did not include these emissions in its analysis of operational emission impacts in DEIR Table 4.2-4.

[257] DEIR, Appx. B-3.

[258] DEIR, Appx. B-3, Table A-2.

Response G1-78.201

Table 4.2-4 of the DEIR analyzed the peak normal operating day. During equipment startup and shutdown, total mass emissions are typically less than the peak normal operating day. Total mass emissions are the product of the emission concentration and emission rate. Permit conditions include limitations of short-term concentration and mass emissions and also include requirements to vent to specific control devices. During startup and shutdown, equipment may exceed the short-term concentration limit but is operating at a lower rate as it comes on-line or shuts down, and, therefore, is operating at a lower emission rate, which results in less mass emissions than the peak normal operating day emissions. Thus, on a daily basis, mass emissions would not be greater than the peak normal operating day emissions.

For existing heaters, emissions during heater startup and shutdown periods will not change after the proposed project is implemented because the frequency and duration of the low rate of heater firing during these periods will remain the same. Startup and shutdown procedures contain gradual warm-up and cool-down requirements to protect the equipment from thermal shock. These same procedures will be followed before and after the proposed project is implemented. During startup and shutdown conditions, daily mass emissions are not expected to exceed peak normal operating day emissions. The product of the firing rate, which is low, multiplied by the NOx concentrations, which may be higher at these low rates, is expected to be less than the peak normal operating day emissions.[195] The same principle applies to CO and VOC emissions during startup. The duration and fired duty during startup and shutdown conditions will not change. Thus, the emissions from these heaters will not change as a result of the proposed project's permit description modifications allowing the firing rates of several heaters to increase. New heaters will startup at low firing rates and would be expected to have less daily emissions during startup than a peak normal operating day. Therefore, the emissions presented in Table 4.2-4 of the DEIR represent the worst-case (i.e., greatest impacts) from the proposed project.

The permit condition A99.X referenced in the comment will limit NOx emissions by explicitly limiting startup and shutdown events to no more than 48 hours per event, as analyzed in Section 4.2.2.4 and Appendix B-3 pages B-3-263 through B-3-295 of the DEIR. A99.X further limits emissions from this heater since no such limit currently exists. All new and modified heaters at the Refinery will be permitted with startup and shutdown limitations similar to A99.X, restricting duration, or emissions during these startup and shutdown events. It should be noted that a condition similar to E54.9, that applies to the DCU H-100 heater and associated SCR, apply to other heaters with SCR for NOx emissions control. E54.9 provides an allowance not to vent the heater exhaust to the SCR during startup and shutdown conditions and until the SCR reaches the necessary operating temperature of 550 ºF. Under normal operating conditions, the heater is required to vent to the SCR. Therefore, NOx emissions will be controlled during startup once the SCR reaches its required operating temperature of 550 ºF.

It should be noted that the ambient air quality modeling has 1-hour and annual standards for NO_2. To conservatively analyze the impact of the proposed project's NOx emissions, the startup and shutdown events for new and modified sources were included in the ambient air quality modeling (see modeling analysis included as Appendix B-3 to the DEIR). As shown in Appendix B-3, Table 10, ambient air quality standards for NO_2 (which is formed from NOx) are not exceeded as a result of this conservative analysis of the proposed project.

CO and VOC emissions do not typically require the use of a control device to maintain compliance with the applicable CO and VOC emissions restrictions. CO and VOC emissions during startup and shutdown events are expected to occur over a very short time period and emissions of these pollutants are expected to fall within the approved emissions rates for these heaters because during startup and shutdown the heaters are operating at a lower emission rate, which results in less mass emissions than the peak normal operating day.

Comment G1-78.202

The SCAQMD CEQA significance thresholds used to evaluate operational emission impacts should be compared to the MAXIMUM day emissions.[259] Thus, the net increase in emissions due to the Project should be the maximum potential daily increase, which occurs during periods of startup, shutdown, and commissioning. The DEIR estimated 720 hours per year of SSC emissions would occur for each fired source. The Title V permits for fired sources explicitly exempt periods of startup and shutdown from complying with NOx limits.[260] The DEIR based its analysis of operational

G1-78.202

[195] The most recent startup of DCU H-100 heater occurred on November 24 and 25, 2012 and the daily startup emissions ranged from 62.1 lb/day to 165.0 lb/day (startup lasted more than one day) based on reported RECLAIM data. These values are less than maximum firing rate emissions of 181.44 lb/day.

emission changes due to the Project on the average daily increase, excluding the maximum day.[261]

The DEIR, Appendix B-3, Table A-2, reports SSC emissions for NOx, but fails to report SSC emissions for CO or VOCs, which would also increase due to incomplete combustion during SSC conditions. As demonstrated below, NOx emissions are significant when SSC emissions are used to calculate the increase in NOx emissions.

For example, for the Wilmington H-100 heater, the DEIR indicates that the maximum daily nonroutine, startup, shutdown, and commissioning emissions are 881.27 lbs/day.[262] Using this revised estimate of the post-modification potential emissions, the net increase in NOx emissions from heater H-100 would be 528.80 lb/day, not -171.03 lb/day as reported in DEIR Table 4.3-4.[263] Correcting just the emissions from this one heater, the net increase in NOx emissions for the entire Project would increase from -38.18 lb/day to 662 lb/day,[264] which exceeds the CEQA significance threshold of 55 lb/day by a significant amount. Making similar corrections to other fired sources in DEIR Tables A-3 and A-4 would result in even greater exceedances of the NOx significance threshold. Similar results are expected for CO and VOC, which increase significantly during startups and shutdowns. Thus, the DEIR has misrepresented the significance of Project emission changes by comparing average daily changes to thresholds based on the maximum day.

G1-78.202 cont'd.

[259] SCAQMD, CEQA Air Quality Handbook, April 1993, p. 6-3 ("In determining whether or not a project exceeds these thresholds, the project emissions should be calculated in the same manner as that for the SCAB (e.g., utilizing the highest daily emissions)".

[260] Draft Wilmington Title V Permit, Condition A99.X, pdf 19; Draft Carson Title V Permit, Condition A99.X1, pdf 46.

[261] DEIR, Table 4.2-4 and Appx.B-3, Table A-2.

[262] DEIR, Appx. B-3, p. B-3-49, Table A-3.

[263] Post-modification NOx emissions from heater H-100: 881.27-352.47 = **528.8 lb/day.**

[264] Net Change in Total Project NOx Emissions = -38.18 + 171.03 + 528.80 = **661.65 lb/day.**

Response G1-78.202

See Response G1-78.201 regarding the use of "peak normal operating day" emissions in the CEQA analysis. Specifically, the emissions presented in Table 4.2-4 of the DEIR represent the worst-case (i.e., greatest impacts) from the proposed project. The emission projections for the proposed project presented in Table 4.2-4 of the DEIR are correct.

The example and emissions provided in the comment regarding the DCU H-100 heater ignore the fact that the frequency and duration of startup and shutdown operational conditions will be the same whether or not the heaters are operated at the current or proposed permit-described heater duties (see Response G1-78.201). As an existing heater, startup and shutdowns of the DCU H-100 heater are existing conditions (have occurred in the past including the baseline period) and emissions will not change as a result of the proposed project.

The permit condition A99.X referenced in the comment will limit NOx emissions by explicitly limiting startup and shutdown events to no more than 48 hours per event. A99.X further limits emissions from the DCU H-100 heater since no such limit currently exists. All new and modified heaters at the Refinery will be permitted with startup and shutdown limitations restricting operating parameters, duration, or emissions during these startup and shutdown events. This is consistent with U.S. EPA's recent Startup, Shutdown, and Malfunction policy.[196]

See Response G1-78.201 regarding the correct calculation of operational emissions of CO and VOC in the CEQA analysis.

Comment G1-78.203

B. The DEIR Used The Wrong Baseline for Heater Emissions

As noted in Comment V.A, the increase in emissions under CEQA is calculated relative to baseline emissions. This calculation uses the same averaging period for the baseline and post-Project emissions. For example, if the CEQA significance threshold is expressed in pounds per day, as here, the baseline and post-Project emissions are both calculated in average pounds per day. The same averaging period must be used in both the baseline and post-Project period. G1-78.203

Response G1-78.203

The CEQA significance threshold is expressed in "pounds per peak day." See Response G1-78.204.

Comment G1-78.204

The DEIR has corrupted the calculation of emission increases from heaters by using different averaging conventions for the baseline and post-Project emissions. This makes it appear that emissions decrease when firing rates increase, when they actually increase, or are much lower than they actually are. G1-78.204

The post-Project emissions in the DEIR are reasonably calculated from an emission factor times the new firing rate. However, the baseline emissions are calculated for each heater based on days where combined actual emissions from the modified heaters were at the 98th percentile of the maximum emissions.[265] The emissions appendix, Appendix B-3, explains: "Emissions Baseline (Daily Basis): Baseline emissions for each combustion unit are calculated as the emissions at the operating day where the emissions were at the 98th percentile of the sum of all modified combustion sources."[266] This, in effect, significantly underestimates the increase in emission from the proposed increase in firing rates of heaters by resulting in a very high baseline value, higher than the average emission rate after the firing rate is increased.

[196] Federal Register Volume 80, No. 113 40 CFR Part 52, June 12, 2015, www.gpo.gov/fdsys/pkg/FR-2015-06-12/pdf/2015-12905.pdf.

For example, the Project proposes to increase the firing rate of Delayed Coker Unit (DCU) Fresh Feed Heater H-100 from 252 MMBtu/hr to 302.4 MMBtu/hr,[267] a 20% increase. Emissions are directly proportional to firing rate unless modifications are made to the heater and/or its controls to reduce emissions. No modifications to heater H-100 or any other similarly modified heater are proposed. Thus, this change in firing rate should increase emissions by a factor of 1.2 (302.4/252 = 1.20). Instead, the emissions summary table shows that this change in firing rate would **reduce** VOC emissions by -0.43 lb/day, CO emissions by -5.14 lb/day, NOx emissions by -171.03 lb/day, PM10 emissions by -0.98 lb/day, and PM2.5 emissions by -0.98 lb/day.[268] The error in NOx emissions for this one heater is sufficient by itself to tip Project NOx emissions over the CEQA significance threshold if NOx emissions are calculated using the correct method.

G1-78.204 cont'd.

[265] DEIR, pp. 4-21, B-3-10, B-3-49, B-3-56, B-3-59/64.

[266] DEIR, p. B-3-10.

[267] DEIR, p. 1-11

[268] DEIR, Table 4.2-4.

Response G1-78.204

Consistent with CEQA Guidelines § 15064.7, the SCAQMD has established significance thresholds that are quantitative. The SCAQMD's significance thresholds are peak daily emissions, not average emissions. The DEIR correctly compares (1) the post-project peak daily potential emissions to (2) the 98th percentile of actual pre-project emissions. As explained in detail in Master Response 12, the SCAQMD's decision to calculate baseline criteria pollutant emissions for modified heaters using a 98th percentile metric, as opposed to an average emissions metric, is reasonable, supported by substantial evidence, and consistent with prevailing guidance and standard practice. This metric was selected because it was a conservative near-peak measurement (i.e., not the absolute highest emissions on any day) based on actual emissions data. The use of near-peak daily emissions corresponds with existing criteria pollutant air quality standards, several of which are based on 24-hour or shorter time periods.

As to the DCU H-100 heater, there will be no physical change to the heater. Rather, the Title V Permit will be revised to reflect the heater's actual maximum level of operation (302.4 mmBtu/hr) rather than the lower level of operation (252 mmBtu/hr) guaranteed by the manufacturer. The DEIR made the conservative assumption that the change in permit description would allow Tesoro to increase the maximum operation of DCU H-100 heater from 252 mmBtu/hr to 302.4 mmBtu/hr. In order to ensure that this assumed increase in operations would not result in any increase in emissions, the SCAQMD imposed a new permit condition that limits daily emissions of criteria pollutants from the DCU H-100 heater to levels that would be generated if the unit were never operated above 252 mmBtu/hr. These limits apply to mass emissions of CO, NOx, SOx, particulate matter less than ten microns in diameter (PM10), and volatile organic compounds (VOC).

The new permit conditions ensure a reduction in emissions from baseline. 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. Draft permit condition D29.xx requires demonstration of compliance with these additional and more stringent emission limitations by source testing. The DEIR (Appendix B-3, page B-3-49) analysis correctly shows a decrease in emissions from the DCU H-100 heater because emissions during the baseline period are higher than the emission limits that will be applied as part of the proposed project.

Comment G1-78.205

The reason that an increase in firing rate appears to reduce emissions, a highly counterintuitive and incorrect result, is that the DEIR used an improper baseline to calculate the change in emissions. Rather than using the average daily emissions in the baseline years (2012, 2013), it used the 98th percentile of the maximum emissions, which is substantially higher than the average daily and thus significantly underestimates emission increases. This is wrong. G1-78.205

Response G1-78.205

See Response G1-78.204 and Master Response 12 regarding the calculation of baseline emissions, the applicable significance threshold, and clarification of the calculation of emission reductions from DCU H-100 heater for the proposed project.

Comment G1-78.206

The SCAQMD permit engineer for the Project also observed that the increase in firing rate of H-100 should have resulted in an increase in emissions:[269] G1-78.206

> Pages 4-15 and 4-17: The emissions change for Wilmington Operation H-100 DCU Heater duty bump indicates reductions in emissions of VOC, CO, NOx, and PM10. The emissions changes are based on post-project potential-to-emit of criteria pollutants minus pre-project actual emissions (98th percentile of maximum emissions for years 2012/2013). The increase in heater firing rate should have associated increases in pollutant emissions. Thus, the use of the 98th percentile of the maximum emissions and/or the years used for baseline emissions should be re-examined.

G1-78.206 cont'd.

The DEIR, in fact, fails to report the average NOx emissions in the baseline years for modified heaters. The DEIR also fails to support the 98th percentile values that it substituted for daily average values in the emission increase calculations. Thus, the heater emission change calculations are not only wrong, but unsupported. The DEIR contains none of the information required to correct these errors.

[269] SCAQMD Application 567649, pdf 939.

Response G1-78.206

The referenced comments made by the SCAQMD permit engineer were on an administrative draft of the EIR, and before permit conditions for the DCU H-100 heater were developed. Since that time, draft permit conditions limiting daily and hourly average emissions have been imposed to ensure there will be emission decreases associated with the permit revision for the DCU H-100 heater.

Baseline emissions for CEQA and pre-project emissions for SCAQMD permits utilize different emissions metrics. For CEQA purposes, use of the 98th percentile is an appropriate baseline metric (see Response G1-78.204 and Master Response 12). For SCAQMD permitting purposes, the pre-project potential to emit for the baseline as defined by SCAQMD Regulation XIII and Rule 2005 was utilized. For both CEQA and permitting purposes, the proposed project results in emissions decreases for many pollutants because emissions during the baseline period were in excess of the emissions limits that will be applied as part of the proposed project. While the proper New Source Review comparison is between pre- and post-project potential to emit, this comparison is not utilized for CEQA.

Contrary to the comment, baseline NOx emissions for modified heaters are provided in Appendix B-3 Attachment A, Tables A-3 and A-4 to the DEIR. The 98th percentile emissions are supported.

Comment G1-78.207

C. Flaring Emissions Were Omitted

The various modifications will include the installation of new pressure relief valves that will vent to the flares.[270] The DEIR asserts:[271]

> "The proposed project includes modifications to existing units and new units that will be connected to vapor recovery and safety flare systems. Additional flaring from normal operations is prohibited by Rule 1118. The project is not expected to increase flaring at the Refinery. There will be no routine vents to the flare system or the flare gas recovery systems from any of the modifications. While the number of pressure relief valves tied in to the flare systems will increase with installation of new or modified process units, this will not cause an increase in flaring. There will however, be additional potential vent sources to the flare gas recovery and flare systems during unit upsets or emergencies."

G1-78.207

However, while these new connections will not increase routine flaring emissions, they will increase emergency flaring emissions, roughly in proportion to the number of new connections to the flares and the assumed capacity of new systems. As discussed for fired sources, the SCAQMD CEQA significance thresholds are based on the maximum day. Thus, emergency flaring emissions must be included in the operational emission summary in DEIR Table 4.2-4. The DEIR does not contain any of the information required to estimate these emissions. However, based on my experience, increased flaring from the increased number of connections to the flares would significantly increase NOx, CO, VOC, PM10 and PM2.5 emissions during flaring events.

The draft Carson Title V permit includes emission increases from connecting the Alkylation Unit to the No. 5 Flare System, but these were not included in the DEIR's emission summary in Table 4.2-4. The draft Carson Title V permit indicates this addition would increase both ROG and CO emissions.

G1-78.207 cont'd.

[270] DEIR, pp. 2-36, 2-37, 2-38, 2-39, 2-43, 2-44, 2-45, 2-46, 4-23.

[271] DEIR, p. 4-53.

Response G1-78.207

As explained below, flaring event emissions will not be increased proportionally to the number of new connections.

The pressure relief valves (PRVs) will not be connected directly to the flare; the PRVs will actually be connected to the flare gas recovery system. The flare gas recovery system is connected to the flare. The flare gas recovery system manages PRV hydrocarbons to its maximum capacity. Once maximum capacity is achieved, the flare, which is in standby mode ready to incinerate excess emissions, is utilized to maintain safety. Connecting PRVs to the flare gas recovery system, instead of allowing them to vent to atmosphere or directly to the flare, is a BACT requirement that also minimizes the need to flare.

The PRV is a safety device that remains closed until its set point pressure is exceeded (i.e., the pressure inside the equipment reaches the set point). More PRV connections to the flare gas recovery system do not increase flaring events proportionally as claimed in the comment, since PRVs are normally closed. PRVs are designed to open only when process operating pressure is significantly above the normal operating pressure. This is a not a frequent occurrence because refinery processes are designed such that the maximum allowable pressure of the equipment, which sets the pressure at which the PRV opens, exceeds the normal operating pressure.[197] 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.

Flaring is restricted by SCAQMD Rule 1118. Normal operations are not allowed to flare. Flaring events are not routine and are allowed only during emergencies, shutdowns, startups, turnarounds, or essential operational needs pursuant to SCAQMD Rule 1118. 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.

Emergency situations that result in venting process gas to the flare are not expected to occur more often or have increased impacts after the proposed project is implemented. Emergency conditions that have resulted in flaring emissions include circumstances such as power failures, fires, and loss of cooling water. The volume of a release is not based on the number of PRVs, but is based on the size and operating conditions of the vessel to which the PRV is connected. For a process unit, the maximum release is based on the volume of the major vessels in the unit and no major vessels are being modified by the proposed project. Emergency flaring events are unexpected, unplanned events, as such, attempting to quantify emergency flaring emissions would be speculative.

Maximum flaring capability will not be changed by the proposed PRV connections. Each time PRVs are added, a maximum worst-case flare flowrate scenario is evaluated to determine if additional flare capacity is needed. The worst-case flare flowrate scenario may not generate the worst-case emissions. The flare capacity analysis is based on the volume of material sent to the flare, and emissions are based on the flow and composition of the stream. In the SCAQMD engineering staff's evaluation, the design of individual vapor recovery systems was reviewed and the associated flares, and it was concluded that there is adequate capacity to accommodate the added PRVs. The PRVs from the proposed project did not alter the maximum potential flare

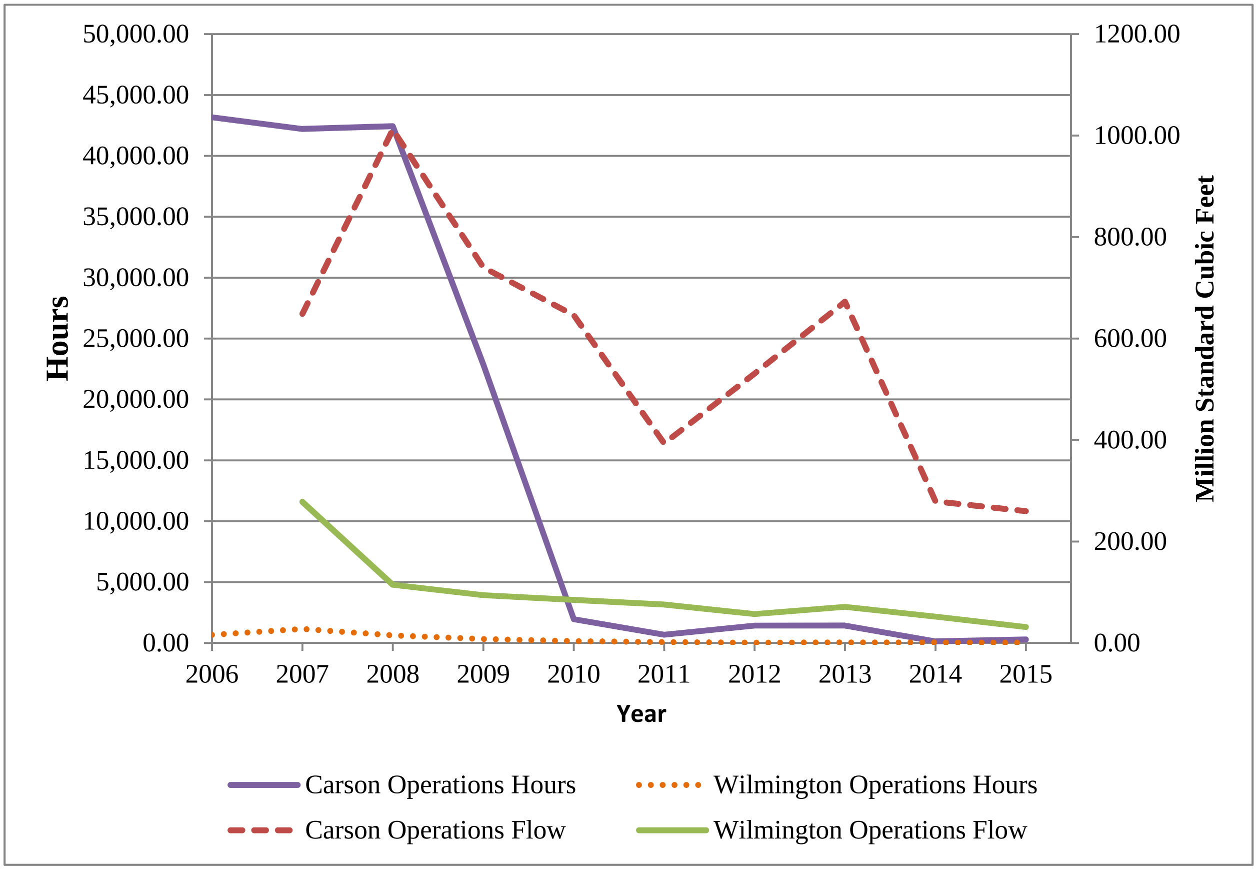
[197] Introduction to Pressure Relief Valve Design Part 1 – Types and Set Pressure http://smart processdesign.com/introduction-pressure-relief-valve-design-part-1-types-set-pressure/.

load, which is limited by the flare tip design, so the flare is adequate to accommodate the potential release from the proposed PRVs. Therefore, no proposed changes to the actual flare are included in the proposed project. However, as required by the SCAQMD permit, the flare system permits will be modified to reflect the addition of the PRVs.

Combustion of hydrocarbons in the flare is the least desired use of hydrocarbons in the Refinery as no saleable product is produced. The intent of the flare gas recovery system is to recover hydrocarbons for use as a fuel. This enables the Refinery to reduce natural gas consumption, since the hydrocarbons are recovered instead of combusted in the flare as waste. Therefore, flaring of vent gases is avoided as much as possible, but is the fallback measure to ensure safe destruction of hydrocarbon vent gases.

The Refinery upgraded the flare gas recovery systems as required by SCAQMD Rule 1118 in 2009. The Carson Operations flares and flare gas recovery system historically operated differently than the Wilmington Operations flares and flare gas recovery system as they were under different ownership and designed differently. As shown in Figure 78.207-1, hours of flaring have been reduced. The hours of flaring have been reduced by approximately 97 and 93 percent for the Carson and Wilmington Operations, respectively, when compared to pre-upgrade flaring activity (2008).

The comment provided no evidence that increasing the number of PRVs connected to the flare and flare gas recovery system would result in an increase in emissions from the flare. In fact, data for the Refinery shows otherwise. Between 2007 and 2015, approximately 90 PRVs were newly connected to the flare and flare gas recovery system. As shown in Figure 78.207-2, the emissions from flaring have no correlation to increasing number of PRVs connected to the flare and flare gas recovery system. Therefore, the comment is unsupported by facts and based on a false assumption. Additionally, the proposed project includes the shutdown of the Wilmington Operations FCCU, which includes removing 44 PRVs from service so that they will no longer have the potential to generate emissions from the flare.

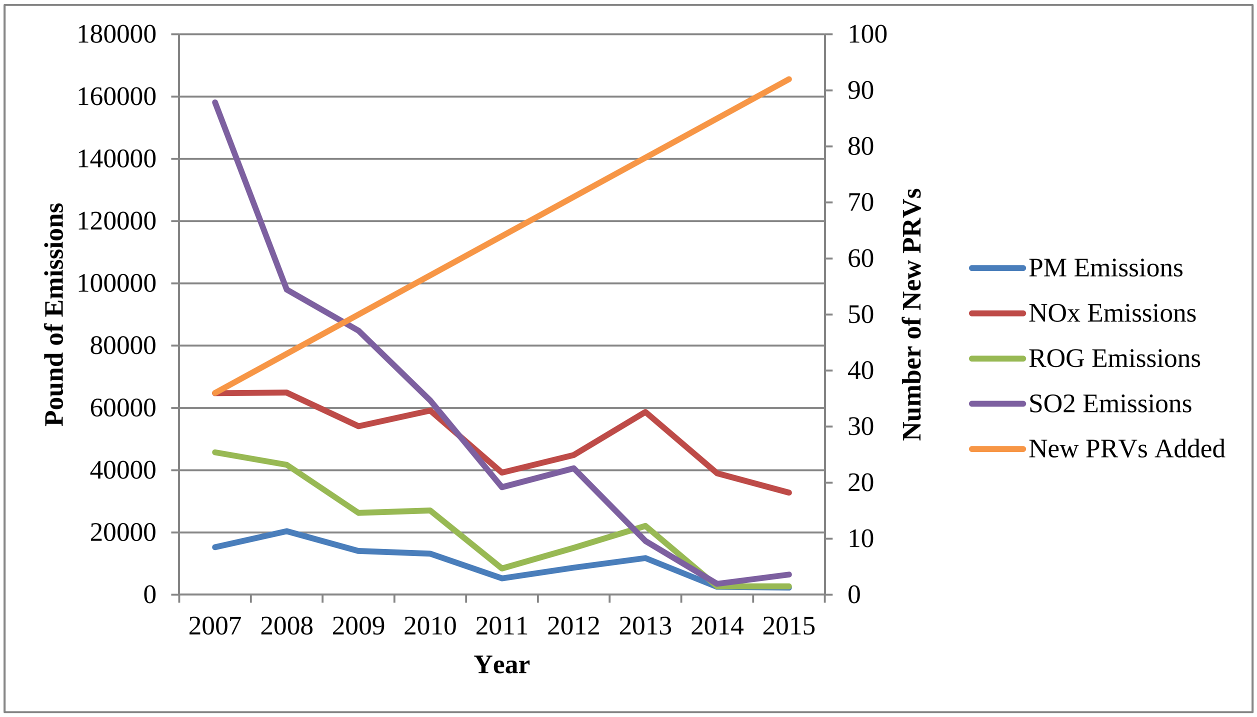


Source: Emissions data: http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-refinery-carson, years 2007 -2015
http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-wilmington, years 2007 -2015
http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/tesoro-sulfur-recovery-plant, years 2007 -2014
Hours data: Tesoro
Note: Carson Operations has five flares; Wilmington Operations has two flares.
Source: Tesoro
Note: Carson Operations has five flares; Wilmington Operations has two flares.

Figure 78.207-1

Historical Hours of Flaring for the Tesoro Los Angeles Refinery (2006-2015)

The emissions from PRVs associated with the Carson Operations Alkylation Unit were included in DEIR Table 4.2-4 as VOC emissions from fugitive components (i.e., included in the 18.88 lb/day emissions) for the purpose of evaluating VOC emissions with the VOC significance threshold. The comment inaccurately states that the Carson Operations Title V permit indicates the PRVs from the Alkylation Unit would result in an increase of CO emissions. The engineering evaluation states: “This project does not result in an increase in criteria pollutant emissions from the flare (see pages 75, 77 and 79 of the engineering evaluation for Carson Operations). PRVs, as non-combustion devices, do not emit CO, so Table 4.2-4 is correct in not including CO emissions associated with the proposed modifications to the Carson Alkylation Unit.



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 78.207-2

Historical Number of PRVs Added to the Flare Gas Recovery System and Historical Flaring Emissions for the Tesoro Los Angeles Refinery (2007-2015)

Comment G1-78.208

D.Emissions Exclude Increases in Crude Throughput

The DEIR asserts that:

> "The total crude oil rate capacity for the Los Angeles Refinery is 363,000 bbl/day. The crude oil rate for Wilmington Operations is primarily constrained by Crude Unit and Coker feed heater duty conditions described in the existing SCAQMD permit. Therefore, the Wilmington Operations is heat limited in its ability to process additional crude oil, which will be modified by the revision to the Heater H-100 permit. The Carson Operations crude rate is constrained by physical limitations of the equipment, including heater duty and pump/piping capacity limitations. In order to increase crude oil processing rate at Carson Operations, physical modifications to the heaters, pumps and piping would have to be made and the appropriate SCAQMD permits would need to be obtained. No such modifications are included as part of the proposed project."[272]

G1-78.208

Tesoro also reported the capacity of the Los Angeles Refinery as 363,000 bbl/day, just after its purchase of Carson.[273] The DEIR also reports a pre-Project capacity of 363,000 bbl/day[274] and indicates the Project would increase the throughput by 6,000 bbl/day by eliminating feed heater duty at the Wilmington Crude Unit and Coker, which would increase the crude capacity to 369,000 bbl/day.[275]

However, this is inconsistent with information reported by Tesoro to the U.S. Securities and Exchange Corporation (SEC) in its most recent Form 10-K, where Tesoro reported that the crude oil capacity of its Los Angeles Refinery is 380,000 bbl/day and its 2015 throughput was 369,000 bbl/day.[276] Similarly, Tesoro's website reports the refining capacity as 380,000 bbl/day.[277]

Thus, Tesoro's current throughput as reported to the SEC equals or exceeds the throughput that the DEIR asserts will be achieved after the Project has been implemented. This suggests that modifications to debottleneck the refinery have already been completed or that the DEIR has understated the impact of the Project on throughput. It further suggests the Project described in the DEIR may further increase throughput, up to 380,000 bbl/day. In either case, emissions would be substantially higher than disclosed as increased throughput means increased emissions.

G1-78.208 cont'd.

These types of issues cannot be reviewed and resolved by the public because the DEIR does not contain any of the information required to evaluate throughput claims, including baseline throughputs, modified processing unit throughputs, and emissions at modified processing units. Thus, the DEIR fails as an informational document and must be revised to include baseline crude throughputs, baseline operating throughputs for each modified refining source, crude source, and crude composition data. The revised DEIR must be recirculated for public review.

[272] DEIR, pp. 2-17, A-151.

[273] Tesoro, Acquisition of BP's Southern California Refining and Marketing Business, August 2012, Slides, p. 31, pdf 32 ("Wilmington/Carson CA 363 MBD"), Exhibit 12.

[274] DEIR, pp. 2-17 and A-151.

[275] DEIR, pp. 1-9, 1-11/12, 1-35, 2-2.

[276] 2015 Tesoro Form 10-K, p. 5.

[277] http://tsocorp.com/refining/los-angelescalif/.

Response G1-78.208

Master Response 5 addresses the current Refinery capacity of 380,000 bbl/day reported in Tesoro's form 10K versus the capacity of 363,000 bbl/day listed in the DEIR. The 10K reported capacity of 380,000 bbl/day has been achieved by the various individual crude oil processing units in the Refinery already. The current Refinery capacity of 380,000 bbl/day has been noted in the FEIR.

The comment assumes that the capacity of the Refinery will change as a result of the proposed project and that the impacts of the capacity increase have not been properly analyzed. The comment concludes that the change in reported Refinery capacity relates to modifications that have occurred or will occur at the Refinery as part of the proposed project. The only increase in crude oil capacity associated with the proposed project is based on the increase in the description of the fired duty of the DCU H-100 heater, and the corresponding potential increase of up to 6,000 bbl/day. The DEIR fully analyzed this increase. As explained below, there are two specific points in Master Response 5 that address the issues raised in the comment: 1) crude oil unit capacity is updated based on the maximum 30-day average capacity achieved for each individual crude oil processing unit during the previous six years; and 2) SCAQMD's permit limits do not typically involve capacity restrictions for process units, since capacity does not necessarily equate to unit emissions.

The first point is relevant because it goes to the issue of the achieved capacity versus capability of a process unit. The Refinery's achieved crude oil capacity was re-evaluated and re-stated in late 2015 in the Tesoro SEC 10K filing. The capability of individual crude oil processing units was not modified; the capability to achieve the reported rates previously existed, but had not been achieved or reported previously. The fact that the capacity evaluation is a six year "lookback" means that each capacity evaluation that is conducted over time is evaluating different operating data. Therefore, the achieved capacity reported may change, as it did in this case. The 380,000 bbl/day has already been achieved and is not a result of the proposed project.

The second point is that SCAQMD permit limits are based on emissions from sources and this emissions information was appropriately analyzed in the DEIR. Emissions from combustion sources are linked to the firing rate of the equipment. Other (non-combustion) emissions from Refinery process units are based on the number and type of fugitive components in VOC service. Since the proposed project does not include the addition of crude oil processing equipment at the Refinery, there are no associated fugitive emission increases. The emissions associated with the 6,000 bbl/day increase in Refinery crude oil processing capacity were appropriately analyzed in the DEIR, based on the incremental firing of Refinery combustion sources (DCU H-100 heater, other downstream process unit heaters, boilers and the Sulfur Recovery Plant). These incremental emission changes are the same regardless of baseline crude oil throughput or capacity.

"The purpose of an environmental impact report is to provide public agencies and the public in general with detailed information about the effect which a proposed project is likely to have on the environment," (Public Resources Code §15204). Here, the baseline information about crude oil capacity for the Refinery as a whole and capacities and emissions for specific modified sources were disclosed. The DEIR provides sufficient information for the public to evaluate capacity claims because the only increase in capacity occurs from the increase in the description of the fired duty of the DCU H-100 heater, and the potential of up to 6,000 bbl/day increase above existing conditions has been fully analyzed (see DEIR pages 4-2 to 4-4 and Master Response 6). The change or increase in firing rate of the DCU H-100 heater, downstream unit heaters, boilers, and the Sulfur Recovery Plant was analyzed and it is the same regardless of the baseline Refinery crude oil capacity or throughput.

Disclosure of more detailed information about crude oil capacity, sources and crude oil composition data is trade secret information as explained in Master Response 2 and not required by CEQA because: (1) it makes no difference with respect to potential Refinery crude oil processing impacts because impacts are analyzed based on the incremental change in processing rate; (2) all crude oils used at the Refinery, whatever their source or composition, will be blended to match the Refinery's crude oil operating envelope and it is a change in this envelope that would trigger different impacts; (3) potential storage and transfer issues were appropriately analyzed in the DEIR based on a worst-case hybrid analysis of the properties of a variety of crude oils currently and potentially processed at the Refinery; and (4) due to the frequent variability in sourcing crude oils, it would be inaccurate, infeasible, and speculative to set either a baseline crude oil slate or a projected crude oil slate at the level of detail that the comment suggests. "CEQA does not require a lead agency to conduct every test or perform all research, study, and experimentation recommended or demanded by commenters." (CEQA Guidelines §15204)

Comment G1-78.209

E. Heater and Other Emission Increase Calculations Use Improper Baseline

The DEIR estimated the increase in emissions from increased firing rates or increased throughputs at certain modified units by multiplying the increase in either firing rate or throughput by an emissions factor.[278] This effectively assumes the permit limit for the baseline. Emission increases for purposes of CEQA must be calculated relative to the baseline, which is 2012 to 2013. The DEIR does not include any baseline emissions for the subject sources. G1-78.209

[278] DEIR, Appendix B-3, Attachment A, pp. B-3-51/52.

Response G1-78.209

The comment questions the calculation methodology used in the DEIR and asserts the equipment permit limits were used as the baseline.

The DEIR did not assume the permit limit as the baseline for increases in emissions due to changes in heater firing. As described in Master Response 12, the DEIR used appropriate data to determine actual near-peak baseline operating rates for modified heaters during the baseline period. The DEIR disclosed the expected additional emissions as compared to the baseline. Emissions from heaters are expected to increase because the equipment is expected to operate at higher utilization levels to accommodate the additional throughput. However, the increases are small enough that the affected equipment will continue to operate within current permit limits, such that no permit modifications are necessary to operate at post-project levels.

The analysis started with the additional 6,000 bbl/day crude oil capacity increase associated with the DCU H-100 heater revised permit description and determined the additional heat input required for heaters in downstream process units that will further process the additional intermediate product from the DCU. In evaluating impacts, the change in the heater firing, over the baseline firing levels, was calculated. In doing so, the DEIR analyzed and fully disclosed the "incremental increase in emissions" above current emission levels that will result from increased utilization of the heat by comparing pre-project energy needs to post-project energy needs (see DEIR, Appendix B-3, Attachment A, pages B-3-51 through B-3-55).

The DEIR emission calculations used the same "emission factors" for heaters that were used to analyze emissions during the permitting of those same heaters. This point, though, has nothing to do with the baseline used when analyzing emissions increases, as the comment suggests. The DEIR used the same emission factors in the environmental impacts analysis as were used in the permitting analysis because the appropriate emission factors for these particular heaters have not changed. Only a physical modification to a heater or a regulatory body's revision to emission factors for certain equipment would alter the emission factors for a particular piece of equipment. Neither of these circumstances has occurred.

For the proposed project, the emission increases result from increased utilization of these existing heaters, not any physical modifications. To calculate the increases in emissions associated with this expected increased utilization, the increased firing rate—above the baseline—is multiplied by the emission factors applicable to each physical heater. Those increases are disclosed in the DEIR. In these calculations, the selected emission factors are not affected by the baseline, they are simply used to calculate the emission increases associated with increased utilization or the increased firing rates of the heaters.

The incremental emissions methodology does not assume the permit limit for the baseline as the comment claims. Rather it evaluates the incremental throughput above the current operating level, which must be less than the permit limit. Otherwise, a permit modification would be needed. The incremental emissions were then included in the operational emissions impacts analysis in Table 4.2-4 of the DEIR. Thus, the incremental emissions were considered when the DEIR concluded that operational impacts would be less than significant for criteria pollutants. (see DEIR pages 4-16 to 4-18).

The FEIR corrects a typographical error in Appendix B-3 Table A-7: "Wilmington Combustion Unit Emissions Calculations (Increased Utilization)" on pages B-3-53 and B-3-54. Table A-7 incorrectly lists "Baseline Emissions" as an item in its "Calculation Basis" column. As explained above, the DEIR did analyze expected additional emissions from heaters as compared to baseline emissions, but that comparison to baseline analysis was conducted to yield the "Incremental Increase" figures that already appear in the Table. Thus, listing "Baseline Emissions" in this location was in error, and has been stricken in the FEIR on pages B-3-67 and B-3-68.

Comment G1-78.210

F. Wilmington FCCU Emission Reductions Are Unsupported

The major source of emission reductions, used to offset Project emission increases, is the shutdown of the Wilmington FCCU.[279] The DEIR contains no support for these huge emission reductions, presenting them as a fait accompli in Appendix B-3 in a table labeled "Wilmington FCCU Shutdown (Historic Actual Emissions)".[280] The parenthetical suggests the reported reductions are "historic actual" emissions, which implies they are measured, as they should be. However, the DEIR presents no further information on how "historic actual" emissions were calculated. This is a serious and significant omission as the FCCU shutdown is the major source of emission reductions used to offset Project emission increases. G1-78.210

[279] DEIR, Table 4.2-4.

[280] DEIR, Appendix B-3, p. B-3-14.

Response G1-78.210

Emission reductions for the Wilmington Operations FCCU are supported in the DEIR. The Wilmington Operations FCCU emission reductions are based on the average historic operating emissions during the baseline period. The average historic operating emissions were obtained through various State and SCAQMD programs, each of which require the reporting of actual emissions. These include emissions reported using agency-approved methods as part of the SCAQMD Regional Clean Air Incentives Market (RECLAIM) program, the SCAQMD Annual Emissions Report (AER) program and the CARB AB-32 program. RECLAIM data is obtained from CEMS, which is real time data collection, source testing, and other permitting requirements. Similarly, AERs are prepared based on actual emissions data, default values, and calculations and are submitted annually to the SCAQMD in order to track emissions from permitted facilities. Additionally, EPA GHG Reports contain emission data from refinery specific processes utilizing fossil fuel combustion and other relevant sources such as hydrogen and petrochemical production. The use of the average historic operating emissions for determining the emission reductions from the Wilmington FCCU, instead of the 98th percentile emissions, provides a lower, more conservative emission reduction calculation for the purposes of determining the significance of the proposed project in Table 4.2-4.

Appendix B-3 Attachment A, Table A-12 to the DEIR specifically lists the source (RECLAIM, AER or AB-32) of these historical emissions. The Wilmington Operations FCCU is comprised of multiple combustion sources including heaters and CO Boiler, the FCCU regenerator, and process vessels. To reiterate the information found in Appendix B-3 Attachment A, Table A-12, CEMS are used to measure NOx and SOx emissions for combustion units such as the FCCU Regenerator, CO Boiler, H-3/4 Heater and B-1 Startup Heater. CEMS are also used to measure SOx emissions for the H-2 and H-5 heaters, but NOx CEMS are not required to be installed on those heaters since they do not meet the definition of Major NOx sources under RECLAIM. Therefore, the permitted RECLAIM NOx concentration limits are used for the H-2 and H-5 heaters. A CO CEMS is used to measure CO emissions from the FCCU Regenerator and CO Boiler. All other sources of CO emissions are calculated using SCAQMD-approved emission factors, concentration limits, or source test data. PM and VOC emissions are calculated using SCAQMD-approved emission factors or source test data. GHG emissions are calculated using

CARB-approved emissions factors. Where appropriate, emissions that were above permit limits were excluded from historic operating emissions used in the DEIR baseline, which is conservative.

Comment G1-78.211

Historic actual emissions can be calculated in various way. The correct way would be to use the average of 2012 to 2013 actual measured emissions data from continuous emission monitoring systems (CEMS) where available,[281] corrected for current BACT. When CEMS data are not available, contemporaneous stack tests at the subject sources should be used. The resulting baseline data should be adjusted to eliminate exceedances of permit limits before calculating daily averages. The DEIR is silent on how it calculated FCCU emission reductions and thus fails as an information document. G1-78.211

The SCAQMD Application for the Project[282] indicates that this method was not used. Instead, generic "emission factors" for fired sources, not specific to the FCCU sources, and annual fuel consumption for 2012 and 2013 were used. The calculations used the same emission factors for NOx, CO, PM, and VOCs for all fired sources within the FCCU unit, even though their controls and operating characteristics differ. No actual measured emissions data was used. Thus, the claimed emissions reductions are suspect. The DEIR must be modified to support these reductions and expanded to include all supporting information, including stack tests, CEMS data, fuel use, and firing rates for the baseline years. G1-78.211 cont'd.

Further, the SCAQMD Application indicates that Tesoro has applied for ERCs for PM10 and VOC emissions from the CO boiler shutdown.[283] Further, correspondence indicates that Tesoro may apply to use additional emission reductions from the shutdown of the FCCU.[284] Thus, the VOC and PM10 emission reductions from shutting down the CO boiler cannot be used to offset Project emission increases.

[281] Aggregate NOx emissions from the FCCU Regenerator, CO Boiler, and Startup Heater are measured by stack CEMS. SCAQMD Application 567649, pdf 936. Thus, this data should be used to establish actual emissions in 2012 and 2013.

[282] SCAQMD Application 567649, pdf 276.

[283] SCAQMD Application 567649, pdf 276, notes.

[284] SCAQMD Application 567649, pdf 516 (Tesoro's responses to SCAQMD question: "There may be more emission reductions associated with shutdown of the Wilmington Operations FCCU (WFCCU) than are required to offset project emissions; in this case Tesoro will request ERCs for the additional emission reductions.")

Response G1-78.211

See Response G1-78.210 for a summary of Wilmington Operations FCCU emission calculations based on actual average emissions reported during the baseline period. Contrary to the claim that historical actual emissions must be corrected for current BACT, as explained below, the DEIR analysis appropriately reflects actual emission reductions that are expected from shutdown of the Wilmington Operations FCCU. The comment presents no authority for the proposition that emissions must be reduced to current BACT, which is not applicable to existing sources such as the Wilmington Operations FCCU (see SCAQMD Rule 1303).

Calculations for any ERCs resulting from the shutdown of the Wilmington Operations FCCU incorporate a discount to current BACT as required by the regulation (see SCAQMD Rule 1306). While SCAQMD regulations require correction to current BACT when calculating ERCs, neither

SCAQMD permitting rules nor CEQA require correction of baseline emissions to current BACT. Therefore, calculations for permitting purposes and CEQA purposes did not incorporate any reductions to include current BACT.

The comment refers to permit application AN 567649 which is for the Carson Operations 51 Vacuum Unit heater, then asserts that emission factors for the Carson Operations 51 Vacuum Unit heater were used for all combustions sources at the Wilmington Operations FCCU. This is inaccurate. The Carson Operations 51 Vacuum Unit heater is unrelated to the Wilmington Operations FCCU unit. Emission factors used for the 51 Vacuum Unit Heater are based on CEMS, unit-specific permit limits, unit specific source test data, and SCAQMD approved emission factors where other such information is not available. Wilmington Operations FCCU fired sources also use CEMS, unit specific source test data, and SCAQMD approved emission factors where other such information is not available. CEMS and source test data are specific to each unit. As stated in Response G1-78.210, all data used to support Wilmington Operations FCCU calculations (source tests, AERs, RECLAIM data) are found in Appendix B-3 Attachment A, Table A-12. All data used to support the Carson Operations 51 Vacuum Unit heater are found in Appendix B-3 Attachment A, Tables A-2 and A-3 on pages B-3-47 through B-3-49.

The comment correctly states that Tesoro has applied for ERCs for PM10 and VOC emissions from the CO Boiler and that Tesoro may apply for additional ERCs upon shutdown of the Wilmington FCCU. The CO Boiler was permanently taken out of service in April 2014 and the ERC application was submitted in October 2014 in accordance with SCAQMD Rule 1306 provisions (reference SCAQMD application number 569408). The emission reductions associated with the shutdown of the CO Boiler are separate from the emission reductions resulting from the FCCU shutdown.

The remaining portions of the Wilmington Operations FCCU will also be retired as part of the proposed project. Tesoro may apply for ERCs for emission decreases resulting from the Wilmington Operations FCCU shutdown in accordance the provisions of SCAQMD Rule 1306. It is correct that emission reductions cannot be used for both concurrent modifications (accounting for proposed project emission increases) and to generate ERCs. The comment assumes, without supporting facts, that Tesoro will request ERCs and offset proposed project emission increases with the same emission reductions. This is not the case. ERCs may be generated for emission reductions that exceed the proposed project increases, as long as issuance of these ERCs does not cause the project to exceed CEQA Significance Thresholds. As shown in Chapter 4, Table 4.2-4 of the DEIR, the “Expected ERCs” to be issued as a result of the proposed project will not cause the proposed project to exceed CEQA Significance Thresholds.

Comment G1-78.212

VI. STORAGE TANK VOC EMISSIONS ARE UNDERESTIMATED

Storage tanks are the major source of VOC emissions, amounting to 322.62 lb/day. Of this amount, 141.64 lb/day is from two new tanks at Wilmington and 112.51 lb/day are from six new tanks at Carson.[285] In addition, conversion of two existing fixed roof tanks to internal floating roof tanks and increased utilization of 11 existing tanks combined contribute an additional 68.4 lb/day.[286] G1-78.212

At the Wilmington tank farm, two new 300,000 bbl internal floating roof storage tanks will replace two existing 80,000 bbl fixed-roof storage tanks (Tanks 80035 and 80036) in the north tank area.[287] At Carson, up to six new 500,000 barrel domed external floating roof crude oil storage tanks will be constructed adjacent to the Carson Crude Terminal.[288]

If VOC emissions from these new and existing tanks were as little as 2% greater than estimated in the DEIR, operational VOC emissions from the Project would exceed the SCAQMD daily VOC significance threshold. This would be a significant impact not disclosed in the DEIR. Due to the large number of errors and omissions in the tank calculations and absence of enforceable VOC emission limits for fired sources, the DEIR should be revised and recirculated for public review. My analysis below indicates that these emissions were significantly underestimated and are significant.

G1-78.212 cont'd.

The increase in VOC emissions due to the omitted VOC sources would be accompanied by an increase in TAC emissions, which are estimated by multiplying the VOC emission increase by the weight percent of each TAC in the ROG emissions (i.e., the TAC speciation profile).

If the inclusion of these omitted emission sources exceeds the significance threshold of 55 lb/day, the SCAQMD must examine the impact of the increase in localized ROG emissions on ambient air quality and the local community and identify mitigation that is capable of reducing or eliminating these impacts to below a level of significance. To mitigate the Project's significant VOC emissions, the SCAQMD should consider feasible mitigation measures such as the use of zero-leak fugitive components; retrofit of geodesic domes on floating roof tanks; and use of cable-suspended, full-contact floating roofs on gasoline storage tanks.[289]

[285] DEIR, Appx. B-3, p. B-3-45.

[286] DEIR, Table 4.2-4 and Appx.B-3, p. B-3-45.

[287] DEIR, p. 2-39.

[288] DEIR, p. 2-46, Figure 2-16; Appx.B-3, Table 1.

[289] See, *e.g.*, Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, December 2014, Final Negative Declaration (Carson Neg. Dec.), Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf?sfvrsn=2 . and City of Richmond, Chevron Refinery Modernization Project DEIR (Chevron DEIR), Chapter 4.3, pp. 4.3-92, Available at: http://chevronmodernization.com/wp-content/uploads/2014/03/4.3_Air-Quality.pdf.

Response G1-78.212

The comment summarizes the conclusions reached in section VI of the comment letter. Detailed responses are provided as noted in Table 78.212-1.

Table 78.212-1

Topics Raised in Comments and Location of Responses

Topic	Response: Master Response Number	Response: Specific Response Number
Storage Tank Emissions Calculations	-	G1-78.213 – G1-78.216
Storage Tank Emissions Omissions	-	G1-78.217 – G1-78.221

Note: - = No Master Response prepared on this topic.

Contrary to the assertion that VOC emission limits for "fired sources" are unenforceable, the proposed Title V permit revisions for the DCU H-100 heater at Wilmington Operations and the No 51 Vacuum Unit heater at Carson Operations both contain enforceable VOC emission limits requiring periodic compliance demonstrations.[198] The comment does not provide any support for the assertion that fired source VOC limits are unenforceable.

Further, the comment asserts that the DEIR could exceed VOC significance thresholds, requiring feasible mitigation measures such as "zero-leak fugitive components; retrofit of geodesic domes on floating roof tanks; and use of cable-suspended, full contact floating roofs on gasoline tanks." For all new and modified fugitive component sources which trigger BACT, as part of the project design, Bellows-Sealed Valves (BSVs) are required with some exemptions due to safety considerations and other considerations. Permit applications for new and modified storage tanks have not yet been submitted for this portion of the proposed project. Currently it is anticipated that the storage tanks will meet BACT through internal or external domed floating roofs. However, the final BACT determination will be made after permit applications are submitted in accordance with SCAQMD Regulations IX and XIII.

It should be noted that VOC emission calculations for the new and existing storage tanks were based on ultra-conservative assumptions to ensure that emissions were not underestimated. The conservative assumptions that were utilized in storage tanks emission calculations include: use of worst-case high vapor pressure materials, use of large storage tank throughputs, and use of worst-case toxic concentrations in the material. The result is higher emission projections than the actual conditions that are expected to exist at the Refinery during normal operations after implementation of the proposed project. Thus, the emissions represented in the DEIR are conservatively high and still below CEQA significance thresholds.

Existing storage tanks will continue to comply with all enforceable product, vapor pressure, and throughput limitations required by the Title V permit. New and modified storage tanks will be required to comply with current BACT as well as to maintain compliance with similar product,

[198] Tesoro Los Angeles Refinery Carson and Wilmington Operations Draft Title V Permit Los Angeles Refinery Integration and Compliance (LARIC) Project Draft Permits.

vapor pressure and throughput limitations once permits are evaluated and issued for the storage tanks.

It should also be noted that the comment is internally contradictory. First, the comment asserts that emissions from tanks have been underestimated, and then it refers to omitted emission sources in the final paragraph of the comment. The comment provides no basis for the claim that emission sources have been omitted from the DEIR analysis. As shown in Table 4.2-4 of the DEIR, VOC emissions are less than significant; therefore, no mitigation is required.

Comment G1-78.213

A. The TANKS Model Underestimates VOC Emissions

The DEIR used the EPA model, TANKS 4.0.9d, to estimate tank VOC emissions. The EPA no longer recommends using this model to calculate tank emissions. The TANKS website cautions "use at your own risk." Rather, EPA recommends using G1-78.213

equations and algorithms in AP-42, Chapter 7 to estimate VOC emissions from storage tanks:[290]

> *provide assistance to users of TANKs 4.09d. The model will remain on the website to be used at your discretion and at your own risk. We will continue to recommend the use of the equations/algorithms specified in AP-42 Chapter 7 for estimating VOC emissions from storage tanks. The equations specified in AP-42 Chapter 7*

G1-78.213 cont'd.

[290] EPA, TANKS Emissions Estimation Software, Version 4.09D; Available at https://www3.epa.gov/ttnchie1/software/tanks/.

Response G1-78.213

The comment has taken out of context the phrase "use at your own risk" on the U.S. EPA TANKS website. The complete statement on the TANKS website is found at https://www3.epa.gov/ttn/chief/software/tanks/index.html and is as follows:

> "The TANKS model was developed using a software that is now outdated. Because of this, the model is not reliably functional on computers using certain operating systems such as Windows Vista or Windows 7. We are anticipating that additional problems will arise as PCs switch to the other operating systems. Therefore, we can no longer provide assistance to users of TANKs 4.09d. The model will remain on the website to be used at your discretion and at your own risk. We will continue to recommend the use of the equations/algorithms specified in AP-42 Chapter 7 for estimating VOC emissions from storage tanks. The equations specified in AP-42 Chapter 7 (https://www.epa.gov/ttn/chief/ap42/ch07/index.html) can be employed with many current spreadsheet/software programs."

The "use at your own risk" statement thus refers to the PC operating system, not the use of the TANKS program. The TANKS program continues to operate successfully on many current operating systems. The TANKS program continues to be used by both SCAQMD engineering staff and the industry to calculate storage tank emissions for permit to construct evaluations as well as emission inventories. Notably, the U.S. EPA TANKS emissions model implements the equations and algorithms in AP-42, Chapter 7 (i.e., precisely what U.S. EPA recommends in the quote cited in the comment).

In fact, U.S. EPA recommends in its Emission Estimation Protocol for Petroleum Refineries, Version 3, April 2015 (see https://www3.epa.gov/ttn/chief/efpac/protocol/Protocol%20 Report%202015.pdf),), ". . . that the emission estimation procedures detailed in Chapter 7.1 of AP-42 (U.S. EPA, 1995a) be used to calculate air pollutant emissions from organic liquid storage tanks. There are many tools available, such as TANKS v4.09D emission estimation software that can be used to perform the necessary calculations. …Because TANKS v4.09D is widely used, Appendix C of this Refinery Emissions Protocol document provides tips and insights on using the TANKS program." In fact, use of the U.S. EPA TANKS program is one of the primary options recommended by U.S. EPA in the protocol (see Chapter 3 pages 3-1 through 3-6 of the referenced protocol). In this same protocol, U.S. EPA states: "There are other direct measurement methods that have been used to measure emissions from storage tanks even when the emissions from the tank are not vented [i.e., DIAL (Differential Absorption LIDAR) techniques]; however, these methods do not provide continuous monitoring and have additional limitations (requiring consistent wind direction, etc.). Therefore, at the present time they are not recommended as primary techniques for annual emission estimation."

In addition to U.S. EPA's recommendation to use the U.S. EPA TANKS project, the U. S. EPA TANKS program is the methodology approved and utilized by SCAQMD engineering staff for all CEQA, permitting and AER storage tank emissions calculations. SCAQMD specifically references use of the U.S. EPA TANKS emissions model in its instructions to the AER as follows: "Facilities with a large number of storage tanks should calculate and report tank emissions using a software program entitled "TANKS" available from the U.S. EPA. The results from TANKS calculation can then be imported to the AER Program via web-based reporting tool" (see http://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/ supplemental-instructions-for-liquid-organic-storage-tanks.pdf?). Several other locations within the AER instructions and guidance also refer to use of the U.S. EPA TANKS program.

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Further, the TANKS 4.09d model used by the DEIR is known to underestimate VOC emissions in certain circumstances. These circumstances apply to existing Project tanks that will experience increased throughput, including the following:

- For heated tanks, TANKS incorrectly assumes that vapor-space and liquid-surface temperature ranges are equal, when this is not always the case. Wilmington tank 80067[291] is a heated tank.
- TANKS does not incorporate temperature as a variable when determining unheated, fixed-roof tank working losses. Instead, it assumes a fixed vapor-space temperature of 63 F. Carson tanks 062, 063, 502 and 959 and Wilmington tanks 80038 and 80074 are unheated, fixed-roof tanks.
- TANKS does not accommodate tanks that receive warmer-than-ambient stock but are not heated. Many of the increased utilization tanks store products that may have warmer than ambient temperatures, including gas oil, naphtha, and alkylate stored in Carson tanks 14, 31, 62, 63, 64, 502, and 959 and Wilmington tanks 80211, 80215, 80217, and 80038.
- Default inputs used for complex mixtures such as crude oil do not accurately capture the large variations in vapor pressure and composition.

In these circumstances, EPA recommends the calculation procedures included in AP-42, Chapter 7.[292] However, these also underestimate tank emissions. It is well

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known that both the TANKS model and the AP-42 algorithms underestimate VOC emissions.[293] Actual measurements of tank emissions using DIAL compared to those calculated using AP-42 indicate that AP-42 underestimates VOC emissions by factors of 2 to 15, as demonstrated in the following summary data:

**Table 6.
Comparison of DIAL Results and
Tank Emissions Estimated Using AP-42.[294]**

Source	Source Description	Compound	Average DIAL flux, lb/hr[a]	Estimated emissions using standard estimating procedures with actual conditions at the time of the DIAL test, lb/hr
Tanks 1020, 1021, 1024, and 1025	EFR[c] tanks storing crude oil	VOC	6.4[d]	1.3 – 1.9[e]
Tanks 1052, 1053, and 1055	EFR tanks storing crude oil	VOC	16.3[d]	1.8 – 2.3[e]
Tanks 501, 502, 503, and 504	EFR tanks storing light distillates	VOC	8.6[d]	3.0 – 3.9[e]
Tank 43	VFR[f] tank storing fuel oil #6	VOC	2	1.3
			9.3	1.3
Tanks 60, 63, 11, 12, 18, 42, 61, and 65	VFR and EFR tanks storing various products	VOC	9	0.6 – 9.1[e]
Tanks 54, 55, 56, and 98	VFR and EFR tanks storing various products	VOC	3.1[d]	0.3 – 9.7[e]
Tanks 53 and 55	VFR tanks storing diesel fuel	VOC	23.8[d]	4.8 – 5.2[e]

Another recent study concluded that "[c]rude oil and heated oil tank emissions measured by DIAL were 5-10 times higher than estimated by TANKS.[295]

G1-78.214 cont'd.

[291] Wilmington Title V Permit, pdf 91.

[292] ERA Environmental, Storage Tanks Emissions Calculation Guide, p. 18, Available at: http://www.era-environmental.com/en-US/pdf/storage-tank-emissions-calculation-guide.pdf; Trinity Consultants, Calculating Tank Emissions with TANKESP, January 7, 2016, Available at: http://www.trinityconsultants.com/news/environmental-quarterly/calculating-tank-emissions-with-tankesp; Sage Environmental Consulting, TankESP; Available at: http://www.sageenvironmental.com/air_quality/tankComparison.

[293] See literature review in EIP, Comments on EPA's Draft "Emission Estimation Protocol for Petroleum Refineries, March 31, 2010, p. 5, Exhibit 29.

[294] U.S. EPA, Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City, Texas, November 2010, Table 2; Available at: https://www3.epa.gov/airtoxics/bp_dial_review_report_12-3-10.pdf.

[295] Rod Robinson, The Application of Differential Absorption Lidar (DIAL) for Pollutant Emissions Monitoring, January 2015, pdf 46; Available at: http://www.h-gac.com/taq/airquality/raqpac/documents/2015/Jan%2015/DIAL%20%202015%20Houston%20Meeting%20January%20(sent%20version).pdf.

Response G1-78.214

As noted in Response G1-78.213, the U.S. EPA TANKS program is the U.S. EPA and SCAQMD recommended program for estimating storage tank emissions. Notably, for DEIR emissions calculations, the following responses regarding accuracy of calculations apply:

Comment Bullet 1: Wilmington Operations Tank 80067 was analyzed for modifications to store crude oils with an RVP of 10.5 psia, which will not be heated. Therefore, this tank was not evaluated as a heated tank in the DEIR (see DEIR Appendix B, pages B-3-199 through B-3-204 for an example).

Comment Bullet 2: The TANKS program inputs for tanks storing materials at ambient temperatures were manually adjusted to the local average ambient temperature where appropriate (see for example, DEIR Appendix B, pages B-3-137 through B-3-144 for an example).

Comment Bullet 3: The TANKS program inputs for tanks storing materials at higher than ambient temperatures were manually adjusted to the higher temperature in order to accurately calculate emissions from these materials at the actual storage temperatures (see DEIR Appendix B, pages B-3- 182 through B-3-188 for an example).

Comment Bullet 4: As indicated in Response G1-78.125, the DEIR has evaluated the emission increases from storage tanks using a conservatively high vapor pressure of crude oil materials and worst-case hybrid analysis of the actual toxic content of crude oils stored at the Refinery (see DEIR Appendix B, pages B-3-122 through B-3-124). TANKS program "defaults" for these inputs for crude oil were not used.

Additionally, the comment states that the U.S. EPA TANKS model and the U.S. EPA AP-42 algorithms underestimate VOC emissions. This assertion is based on a March 31, 2010 comment to U.S. EPA (http://www.law.uh.edu/faculty/thester/courses/Emerging%20Tech%202011/20100331_EIPCommentsonRefineryEmissionsProtocol.pdf) regarding the preparation of the U.S. EPA Emission Estimation Protocol for Petroleum Refineries (see Response G1-78.213). U.S. EPA considered all comments received regarding the emissions estimation protocol and continues to recommend the U.S. EPA TANKS model and the U.S. EPA AP-42 algorithms for storage tank emissions calculations (see Response G1-78.213 and referenced document found at https://www3.epa.gov/ttn/chief/efpac/protocol/Protocol%20Report%202015.pdf).

Response G1-78.213 addresses why other calculation methodologies, such as DIAL, are not recommended for use by U.S. EPA at this time. Further, use of DIAL is still under development and there is no U.S. EPA approved reference method for use of this technology. Per U.S. EPA Emission Estimation Protocol for Petroleum Refineries, use of DIAL is not recommended as a primary technique for emissions estimation. The currently accepted methods such as the equations published by U.S. EPA AP-42, and as implemented by the TANKS program, will continue to be used (see https://www3.epa.gov/ttn/chief/efpac/protocol/Protocol%20 Report%202015.pdf; Section 3.1).

Comment G1-78.215

B. The TANKS Model Inputs Underestimate Emissions

Vapor pressure and vapor molecular weight are key inputs to the TANKS model. The higher the vapor pressure and vapor molecular weight, the greater the VOC emissions. The DEIR assumed a vapor pressure for "light crude oil" of 10.5 psi and a vapor molecular weight of 50 lb/lb-mol. These assumptions are not realistic for Bakken crude oils, which will be imported and refined by this Project. They both underestimate VOC emissions. G1-78.215

First, as noted in Comments II.B.1 and II.E.2, Bakken crude oils are known to have much higher true vapor pressures than the 10.5 psi RVP used to estimate VOC emissions, ranging up to 16 psi reported as RVP.[296] The TANKS model runs assumed an RVP of 10.5 psi. As explained in Comment II.B.1, this corresponds to a true vapor pressure of about 11.5 psi, which would be permitted at 11 psi due to federal and SCAQMD regulations that limit vapor pressure of material in storage tanks without special controls.

However, as a practical matter, tank vapor pressure limits are rarely enforced as routine monitoring is not required to confirm the limits. None of the tank vapor pressure limits in the existing Carson and Wilmington Title V permits, for example, require any monitoring. The vapor pressure monitoring for tanks in the Wilmington Title V permit:[297]

> D90.18 The operator shall periodically monitor the vapor pressure of the material stored in this storage tank according to the following specifications:
>
> The operator shall determine the true vapor pressure by one of the following methods: 1) sample and test the materials stored, 2) derive the vapor pressure using engineering calculations, or 3) maintain on file a copy of the Material Safety Data Sheet (MSDS) of the material stored.
>
> Records of material stored, and their MSDS if applicable, shall be retained for a period of five years and made available to the Executive Officer upon request.

G1-78.215 cont'd.

The vapor pressure monitoring for tanks in the Carson Title V Permit:[298]

> K67.21 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):
>
> The operator shall determine the true vapor pressure of each material stored in the equipment by one of the following methods: 1) sample and test the materials stored, 2) derive the vapor pressure using engineering calculations, or 3) maintain on file a copy of the Material Safety Data Sheet (MSDS) of the material stored.
>
> Records of material stored, and their MSDS if applicable, shall be retained for a period of five years and made available to the Executive Officer upon request.

These conditions do not require any actual monitoring as they allow the substitution of unspecified engineering calculations or reliance on a MSDS, a document that is not specific to any load of crude oil and is not routinely updated. And compliance need only be determined "periodically." This condition grants full discretion to the applicant and is not enforceable. The DEIR must require enforceable vapor pressure monitoring using ASTM D6377, at 100 F and a vapor-liquid ratio of 4:1 at least quarterly or when material stored in the tank changes. Otherwise, VOC emissions from new and modified storage tanks must be calculated using the maximum measured vapor pressure for Bakken crude oil.

G1-78.215 cont'd.

Thus, even if vapor pressure limits are established in the permit to operate, these limits would not be valid mitigation or guarantees under CEQA that higher vapor pressure materials would not be stored in the tanks. Thus, higher VOC emissions could occur unless mitigation requires mandatory and enforced monitoring and reporting.

[296] Intertek, Report of Analysis, Bakken Crude, March 2014; Available at: http://desmogblog.com/sites/beta.desmogblog.com/files/Northern%20Plains%20Bakken%20Crude%20Oil%20Sample%20Chemical%20Composition.pdf; ConocoPhillips, Safety Data Sheet, Bakken Crude Oil, Sweet, p. 5; Available at: http://www.conocophillips.com/sustainable-development/Documents/2014.05.30%20825378%20Bakken%20Crude%20OiL%20Sweet.pdf; Dangerous Goods Transport Consulting, Inc., A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation, May 14, 2004, p. 5; Available at: https://www.afpm.org/uploadedFiles/Content/documents/Survey-of-Crude-Oil-Characteristics.pdf.

[297] Wilmington Title V Permit, July 7, 2015, pdf 271.

[298] Carson Title V Permit, January 29, 2016, pdf 554.

Response G1-78.215

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9, and Response G1-78.94, the proposed project is not designed to facilitate a change in 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. See Response G1-78.125 regarding misleading and unsupported assertions in the comments that storage tanks will contain crude oils with much higher vapor pressures than the RVP 10.5 (11 psia TVP) and that vapor pressure limits are not enforceable or "rarely enforced".

A TVP of 11 psia is the maximum allowed vapor pressure of SCAQMD Rule 463, U.S. EPA NSPS Kb and U.S. EPA MACT CC for floating roof tanks. Additionally, vapor pressure testing is already required by SCAQMD Rules 463 and 1178 and the analytical test methods for analyzing VOC emissions are prescribed by these rules. Specifically, the analytical test methods that are required to be used for the determination of vapor pressure of stored materials are found in SCAQMD Rule 463(h)(3) and (h)(5) and SCAQMD Rule 1178(i)(4). As set forth in these regulations, SDSs are not used to determine the vapor pressure of light crude oils as suggested in the comment. SCAQMD will monitor compliance with the provisions of these applicable rules using vapor pressure test methods prescribed by these rules. Additionally, Tesoro is required to certify compliance with these requirements, under penalty of perjury, on a semi-annual basis through the Title V Semi-Annual Monitoring and Annual Compliance Certification reports to SCAQMD. Therefore, maximum vapor pressure limitations will be enforced, as appropriate, through the issuance of Title V permit conditions for the new and modified floating roof storage tanks associated with the proposed project and additional conditions are not required (see Title V permit Section K, which identifies these SCAQMD rules as applicable to the Refinery).

The permit conditions referenced in the comment, D90.18 and K67.21, are merely several of numerous conditions in the existing Title V permit that enforce vapor pressure limits. Conditions D90.18 and K67.21 are typically used for storage tanks handling materials with very low vapor pressure. For tanks storing heavy materials, routine testing may not be required to demonstrate compliance with the limits since the materials stored usually have vapor pressures far below any regulatory or permit limits. Note that there are no commercial laboratories that run approved analytical methods for testing vapor pressure of heavy residual materials. In addition, analytical methods for testing vapor pressure of heavy residual materials are not specified in SCAQMD Rules 463 and 1178. In these cases, as allowed by permit conditions D90.18 and K67.21, as cited by the commenter, vapor pressure may be estimated using SDSs or engineering calculations. In any event, as noted in Response G1-78.157, SDSs contain conservative, health protective information that tend to overstate chemical and physical properties of the subject materials. Per permit Conditions D90.18 and K67.21, vapor pressure evaluations are currently required and performed on each material stored in each tank subject to these conditions and/or SCAQMD Rules 463 and/or Rule 1178.

Vapor pressure testing is conducted by the Refinery on a variety of products and materials stored in tanks. In order to meet product specifications, gasoline and gasoline blending components are tested as they are produced from the process units and in final blending tanks. In order to ensure compliance with Title V permit requirements, Tesoro performs routine vapor pressure laboratory testing on high vapor pressure materials, including crude oils and maintains the results of the analysis on file. Under the Title V permit program, the Refinery is required to self-certify compliance with all conditions of the Title V permit, under penalty of perjury, on a semi-annual basis. As previously mentioned, compliance with the maximum vapor pressure limitations is part of that certification

Comment G1-78.216

Second, the TANK model runs for "light crude oil" assume a vapor molecular weight of 50 lb/lb-mol. However, the EPA default for much heavier crudes with a RVP of 5 psi is 50 lb/lb-mol.[299] A lighter crude oil would have more volatiles and thus a higher vapor molecular weight. The volatility of Bakken crude oils is more similar to gasoline than conventional 5 psi crude oil. The vapor molecular weight of an RVP 10 psi gasoline is 66 lb/lb-mol.[300] Alternatively, Bakken crude oil is more similar to naphtha (light, medium and heavy), which the DEIR assumed had a vapor molecular weight of 60 lb/lb-mol. Vapor molecular weight is not limited in permits to operate. Thus, this TANKS input, which determines VOC emissions, is not enforceable. This input should be restricted by a permit limit that requires monitoring and reporting to satisfy CEQA mitigation requirements. G1-78.216

[299] EPA, AP-42, Table 7.1-2.

[300] Ibid.

Response G1-78.216

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9, and Response G1-78.94, the proposed project is not designed to facilitate a change in 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.

Contrary to the claim in the comment, Bakken is not more like a gasoline than a crude oil in the composition of its vapor phase. Like other crude oils, Bakken contains small amounts of ethane, propane, butane, and pentane. These are the primary contributors to the molecules in the vapor phase above a crude oil. As noted in Table 78.216-1, Bakken is very typical of other light crude oils in its composition and therefore it should be, and is, regulated like other crude oils.

Table 78.216-1

Light Sweet Crude Assay Comparison

Property	Unit	Crude Oil		
		Bakken[1]	WTI	LLS
API Gravity	Degrees	> 41	40.0	35.8
Sulfur	Weight %	< 0.2	0.33	0.36
Distillation Yield:	Volume %			
Light Ends	C1-C4	3	1.5	1.8
Naphtha	C5-330 ºF	30	29.8	17.2
Kerosene	330-450 ºF	15	14.9	14.6
Diesel	450-680 ºF	25	23.5	33.8
Vacuum Gas Oil	680-1000 ºF	22	22.7	25.1
Vacuum Residue	1000+ ºF	5	7.5	7.6
Total		100	100.0	100.0
Selected Properties:				
Light Naphtha Octane	(R+M)/2	n/a	69	71
Diesel Cetane		> 50	50	49
VGO Characterization (K-Factor)		~ 12	12.2	12.0

Source: U.S. DOE 2011.
WTI = West Texas Intermediate crude oil; LLS = Louisiana Light Sweet crude oil
[1] Properties are approximate; based on available assay information.

Also, contrary to the claim in the comment, higher vapor pressure products do not typically have higher vapor molecular weights. Actually, high vapor pressure compounds typically indicate the increased presence of smaller and lower molecular weight compounds in the petroleum liquid. These smaller and lighter molecular weight compounds more easily "escape" to the vapor space. For a high vapor pressure mixture of materials with different properties, such as crude oil, the vapor phase will consist of a large proportion of the light ends that escape the mixture and the vapor molecular weight will tend to be low. For a material such as naphtha or summer gasoline, that has been through a distillation column where the light ends have been removed, the vapor phase will essentially be naphtha, with a higher vapor molecular weight. Since higher vapor pressure materials contain lower molecular weight compounds in the liquid phase, these lower molecular weight compounds will migrate into the vapor space. Therefore, 50 lb/lb-mol is a reasonable assumption for the molecular weight of high vapor pressure crude oils stored onsite, and in fact, may overstate the vapor molecular weight. The TANKS calculations for the proposed project used appropriate assumptions and the calculations provide a conservatively high estimate of emissions.

Comment G1-78.217

C. Roof Landing, Degassing, and Cleaning Emissions Were Omitted

The DEIR estimated VOC emissions from storage tanks using EPA's model, TANKS 4.0.9d. This model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses, inspection losses, or flashing losses. Thus, the DEIR underestimated tank emissions by failing to include all sources of tank VOC emissions.

The EPA has explained that the TANKS model used to estimate tank VOC emissions in the DEIR does not include roof landings and recommended that they be estimated with the equations in AP-42, Section 7.1.3.2.2. In other words, the EPA TANKS model estimates evaporative emissions for normal operations only, *i.e.*, it assumes that the floating tank roof is always floating.[301] However, when a tank is

G1-78.217

emptied to the point that the roof no longer floats on the liquid but lands, evaporative losses occur. These losses are uncontrolled tank emissions and can be larger than routine controlled emissions. They are called "roof landing losses." The DEIR did not include these emissions. I cannot estimate them because all of the inputs required to make the calculations are not provided in the DEIR.

G1-78.217 cont'd.

[301] EPA, TANKS Software Frequent Questions, Updated February 2010, Available at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html. ("How can I estimate emissions from roof landing losses in the tanks program? … In November 2006, Section 7.1 of AP42 was updated with subsection 7.1.3.2.2 Roof Landings. The TANKS program has not been updated with these new algorithms for internal floating roof tanks. It is based on the 1997 version of section 7.1.").

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Roof Landing Losses: SCAQMD Rule 463, U.S. EPA NSPS Kb, and U.S. EPA MACT Standard CC require that the floating roofs remain floating on the liquid at all times except when the tank is being completely emptied for cleaning or repair. Tanks associated with the proposed project are also required to comply with SCAQMD Rule 1149 requiring degassing by connecting the storage tank to a control device to achieve less than or equal to 500 ppmv VOC (measured as methane) concentration at the effluent of the control device during roof landing for cleaning or repair [see SCAQMD Rule 1149(c)(8)]. Compliance with these applicable rules ensures that the roofs of these tanks are either floating or connected to a control device at all times. Notably, the use of a control device during periods of roof landings maintains VOC emissions at or below "normal" daily operating conditions as evaluated by the U.S. EPA TANKS program. Therefore, storage tank emissions presented in the DEIR are evaluated using the highest or peak operating day emissions.

Inspection Losses: All floating roof tanks evaluated by this DEIR have either a fixed roof exterior with a floating interior roof or an external floating roof with a geodesic dome. Tank inspections are performed under normal operating conditions when the roof is still floating using only visual and measurement methods (i.e., no opening or removing of the storage tank seals occur). Therefore, additional emissions will not occur as a result of inspection. The operating evaporative emissions during roof inspections will remain the same as normal operating evaporative emissions.

Flashing Losses: Flashing losses typically occur when crude oil pressure is reduced and/or temperatures are increased. Flashing losses typically occur at crude oil production facilities prior to transportation to a refinery. Terminals supplying the Refinery accept only pipeline quality crude oils that do not have the potential for flashing because the crude oil is required to have the light ends removed prior to transport. For example, North Dakota limits the RVP of crude oil provided for transport to 13.7 psi (see Response G1-78.161). Therefore, flashing losses are not expected to occur at terminals supplying the Refinery or in floating roof storage tanks at the Refinery.

Comment G1-78.218

In addition, "degassing and cleaning losses" occur when tanks are drained and degassed for inspection and/or cleaning. These include both roof landing emissions, complete tank degassing, and emissions from cleaning out accumulated sludge. These emissions are essentially uncontrolled tank emissions[302] and can be larger than normal operating emissions if uncontrolled. The DEIR is silent on these emissions. These emissions can be controlled using special degassing equipment.[303] The DEIR does not contain any commitment to use degassing equipment for tank cleaning. G1-78.218

[302] See EPA guidance on estimating these emissions at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13.

[303] See, for example, Envent Corp., Tank & Vessel Degassing; Available at: http://www.enventcorporation.com/services/degassing-vapor-control/tank-vessel-degassing/.

Response G1-78.218

See Response G1-78.217 regarding the requirement to comply with the applicable requirements of SCAQMD Rule 1149 during degassing and cleaning.

Comment G1-78.219

The tank cleaning emissions could be substantially higher for Bakken crudes than for other types of crude. Bakken crudes leave waxy deposits in pipelines and tanks, which require more frequent cleaning,[304] and thus higher cleaning emissions, than the crudes they would replace. Environmental impacts from chemical dispersants used to control these waxy deposits in tanks and pipelines also should be evaluated. G1-78.219

[304] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, Available at: http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html; Gordon Schremp, Trends in Sources of Crude Oil, 2014 IEPR Workshop, June 25, 2014, p. 47; Available at: http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/01_Schremp_Final_2014-06-25.pdf.

Response G1-78.219

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9, 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 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. See Response G1-78.162 which explains that Bakken crude oil is not known to create waxy deposits, so use of additional dispersants is not expected. As the types and quantities of crude oil delivered are not expected to occur, no changes to crude oil storage tank or pipeline cleaning schedules, procedures, or emissions are expected to occur as a result of this proposed project. All tank and pipeline cleanings will continue to comply with the applicable requirements of SCAQMD Rule 1149. As explained in Response G1-78.217, use of a control device during periods of roof landings during cleaning or emptying events maintains emissions at or below "normal" daily operating conditions. The impacts claimed in the comment are not reasonably foreseeable, expected to occur, or supported by facts.

Comment G1-78.220

The EPA recommends methods to estimate emissions from degassing, cleaning, and roof landing losses.[305] The method for estimating emissions depends on the construction of the tank, *e.g.*, the flatness of the tank bottom and the position of the withdrawal line (the so-called liquid "heel"). Degassing, cleaning, and roof landing losses continue until the tank is refilled to a sufficient level to again float the tank roof. Total VOC emissions from floating roof tanks during a roof landing is the sum of

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standing idle losses and filling losses. They can be estimated using formulas contained in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7.1, Organic Liquid Storage Tanks, Section 7.1.3.2.2. These emissions are routinely included in emission inventories. They are required to be reported, for example, in Texas.[306] They are also included in the emission inventory for Tesoro's Vancouver Terminal, which imports similar crudes by rail and stores them in tanks.[307]

G1-78.220 cont'd.

[305] "How Can I Estimate Emissions from Degassing and Cleaning Operation During a Tank Turnaround? And How Can I Estimate Emissions from Roof Landing Losses in the TANKS Program:?", Available at: http://www.epa.gov/ttnchie1/faq/tanksfaq.html#13.

[306] Memorandum from Dan Eden, Deputy Director, Office of Permitting, Remediation, and Registration; David C. Schanbacher, Chief Engineer; and John Steib, Deputy Director, Office of Compliance and Enforcement, Re: Air Emissions During Tank Floating Roof Landings, December 5, 2006, Available at: http://www.tceq.state.tx.us/assets/public/permitting/air/memos/tank_landing_final.pdf.

[307] Tesoro Savage, Application for Site Certification Agreement, Section 5.1.2.1.4, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf.

Response G1-78.220

See Response G1-78.217 regarding the requirement to comply with the applicable requirements of SCAQMD Rule 1149 during degassing and cleaning and the decreased emissions associated with such events due to the required connection to a control device.

Comment G1-78.221

D. Tank Flashing Emissions Were Omitted

Many Bakken crudes are transported raw, without stabilization, due to the lack of facilities in the oil fields. Unstabilized or "live" crude oils have high concentrations of volatile materials entrained in the bulk crude oil. Tank flashing emissions occur when these crude oils, such as Bakken, are exposed to temperature increases or pressure drops, such as may occur on a hot summer day. When this occurs, some of the compounds that are liquids at the initial pressure/temperature transform into gases and are released or "flashed" from the liquid. These emissions are in addition to working and breathing emissions from tanks and are not estimated by the EPA TANKS 4.0.9d model. These emissions can be calculated using standard procedures.[308] The DEIR did not mention or calculate these emissions, nor does it require that only stabilized crude oils be stored in the light crude oil (10.5 psi) tanks 300035, 300036, 80060, 80067, and 80079. G1-78.221

[308] See, *e.g.*, calculation methods at: Paul Peacock, Marathon, Bakken Oil Storage Tank Emission Models, March 23, 2010; TCEQ, Air Permit Reference Guide APDG 5941, Available at: http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf; Kansas Dept. of Health & Environment, Available at: http://www.kdheks.gov/bar/download/Calculation_Flashing_Losses_Handout.pdf; B. Gidney and S. Pena, Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation, July 16, 2009, Available at: http://www.bdlaw.com/assets/htmldocuments/TCEQ%20Final%20Report%20Oil%20Gas%20Storage%20Tank%20Project.pdf.

Response G1-78.221

The comment cites guidance documents relating to unstabilized crude oil at upstream oil and gas production and storage facilities. The Refinery is subject to numerous permit and regulatory restrictions on volatility of commodities that are allowed to be stored in its tanks (see current Carson Operations Title V permit Sections D and H, Process 16, Systems 1-5 and current Wilmington Operations Title V permit Sections D and H, Process 16, Systems 1-7). None of these conditions will be modified as part of the proposed project. The Refinery limits its crude oil acquisitions to stabilized pipeline quality crude oil; therefore, flashing losses, are not expected to occur in storage tanks (see Response G1-78.161).

Comment G1-78.222

E. Water Draw Tank Emissions Were Omitted G1-78.222

Crude oil typically contains small amounts of water, which is separated from the crude oil and accumulates in the bottom of storage tanks. This accumulated water, referred to as water draw, is typically transferred from the crude oil storage tanks into a smaller water draw surge tank for processing prior to disposal. Over time, a thick layer of crude oil forms in the water draw surge tank. The water draw surge tank and processing of wastewaters from it emit VOC and TACs. The DEIR does not mention water draw, or include emissions from storing or processing it, which would increase as the vapor pressure of the stored crude increases, i.e., from a switch from San Joaquin Valley to Bakken crude. G1-78.222 cont'd.

Response G1-78.222

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9 and Response G1-78.94, the proposed project is not designed to facilitate a change in 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 volume of crude oil delivered to the Carson Crude Terminal after project implementation will be the same as is currently being received in existing tankage. Therefore, no change in the amount of water draw for the Carson Operations would occur as a result of the proposed project.

At the Wilmington Operations, the increased capacity of up to 6,000 bbl/day (2.2 million bbl/year) of crude oil associated with the DCU H-100 heater change has the potential to change the amount of water draw. However, the organic fractions of the water draw are small and will not result in significant vapor emissions. Additionally, the water draw at the Wilmington Operations will go to an existing tank controlled by vapor recovery (a closed system), which has the capacity to accommodate any additional water with negligible emissions increase.

The DEIR analyzed the emissions from the increased crude oil delivery as 100 percent of the crude oil and entrained water being delivered to the new 300,000 bbl storage tanks. A very small amount of crude oil is carried with the water sent to the existing tank. All of the emissions associated with the management of crude oil, including water draw emissions, were accounted for at the crude oil storage tanks. As explained in Master Response 9 and Response G1-78.122, crude oils with various properties are blended at the Refinery today. Therefore, the worst-case maximum vapor pressure has already been incorporated into the emission calculations used in the analysis in Chapter 4 of the DEIR.

Comment G1-78.223

F. Tank VOC Emissions Are Significant

In sum, the DEIR has omitted many sources of tank VOC emissions and used an invalid calculation method, known to underestimate tank emissions by factors of 2 to 50. The DEIR does not contain sufficient information to correct the errors or estimate the missing emissions. However, an increase of only 6 lb/day or 2% more than estimated in the DEIR, would be required to exceed the CEQA significance threshold. In my opinion, the many errors and omissions in the tank calculations are sufficient to exceed the VOC significance threshold for the Project. Thus, mitigation for tank emissions must be required.

G1-78.223

Response G1-78.223

This comment summarizes Comments G1-78.212 through G1-78.222. As explained in Responses G1-78.212 through G1-78.222, the DEIR accurately and correctly calculated the potential increase in VOC emissions from the proposed project. Compliance with SCAQMD Regulation XIII requirements to provide VOC offsets is part of the proposed project (see DEIR page 4-18). Therefore, no significant VOC emission impacts were identified and, as such, no mitigation is required.

Comment G1-78.224

To reduce emissions from tank breathing losses, degassing, cleaning and roof landing losses, the EIR should require Tesoro to install geodesic domes on all tanks that do not have them, thus avoiding emissions from these and other tank sources, including Wilmington tanks 300035, 300036, 80060, 80067, and 80079. Further, degassing control equipment should be required for all tank degassing and cleaning events.

Geodesic domes are feasible and should be required for all floating roof tanks affected by the Project. Many of the tanks at the subject facilities already are equipped with domes, including Carson Tanks 014, 031, 063, and 064 and Wilmington Tanks D650, D654, and D656. Further, over 10,000 aluminum domes have been installed on petrochemical storage tanks in the United States.[309] The ExxonMobil Torrance Refinery: "completed the process of covering all floating roof tanks with geodesic domes to reduce VOCs emissions from facility storage tanks in 2008. By installing domes on our storage tanks, we've reduced our VOC emissions from these tanks by 80 percent. These domes, installed on tanks that are used to store gasoline and other similar petroleum-derived materials, help reduce VOC emissions by blocking much of the wind that constantly flows across the tank roofs, thus decreasing evaporation from these tanks."[310] G1-78.224

A crude storage project, recently proposed at the Phillips 66 Los Angeles Carson Refinery, required external floating roof tanks with geodesic domes to store crude oil with an RVP of 11.[311] The ConocoPhillips Wilmington Refinery added a geodesic dome to an existing oil storage tank to satisfy BACT.[312] Similarly, Chevron proposes[313] to use domes on several existing tanks to mitigate VOC emission increases at its Richmond Refinery.[314] The U.S. Department of Justice CITGO Consent Decree required a geodesic dome on a gasoline storage tank at the Lamont, Texas refinery.[315] Further, numerous vendors have provided geodesic domes for refinery tanks.[316] The crudes that would be stored in the Project tanks have vapor pressures that are comparable to gasoline (TSBC 2013, Sec. 3.2.7), justifying the use of geodesic domes to control tank emissions. G1-78.224 cont'd.

[309] M. Doxey and M. Trinidad, Aluminum Geodesic Dome Roof for Both New and Tank Retrofit Projects, Materials Forum, v. 30, 2006, Available at: http://www.materialsaustralia.com.au/lib/pdf/Mats.%20Forum%20page%20164_169.pdf.

[310] Torrance Refinery: An Overview of our Environmental and Social Programs, 2010, Available at: http://www.exxonmobil.com/NA-English/Files/About_Where_Ref_TorranceReport.pdf.

[311] See, e.g., Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, September 6, 2013, Table 1-1, Draft Negative Declaration, Available at: https://www.aqmd.gov/CEQA/documents/2013/nonaqmd/Draft_ND_Phillips_66_Crude_Storage.pdf.

[312] SCAQMD Letter to G. Rios, December 4, 2009, Available at: http://yosemite.epa.gov/r9/air/epss.nsf/e0c49a10c792e06f8825657e007654a3/e97e6a905737c9bd882576cd0064b56a/$FILE/ATTTOA6X.pdf/ID%20800363%20ConocoPhillips%20Wilmington%20-%20EPA%20Cover%20Letter%20%20-AN%20501727%20501735%20457557.pdf.

[313] City of Richmond, Chevron Refinery Modernization Project, Environmental Impact Report, Volume 1: Draft EIR, March 2014 (Chevron DEIR), Available at: http://chevronmodernization.com/project-documents/ .

[314] Chevron DEIR, Chapter 4.3.

[315] CITGO Petroleum Corp. Clean Air Act Settlement, Available at: http://www2.epa.gov/enforcement/citgo-petroleum-corporation-clean-air-act-settlement.

[316] See, e.g., Aluminum Geodesic Dome, Available at: http://tankaluminumcover.com/Aluminum-Geodesic-Dome; Larco Storage Tank Equipments, Available at: http://www.larco.fr/aluminum_domes.html; Vacono Dome, Available at: http://www.easyfairs.com/uploads/tx_ef/VACONODOME_2014.pdf; United Industries Group, Inc., Available at: http://www.thomasnet.com/productsearch/item/10039789-13068-1008-1008/united-industries-group-inc/geodesic-aluminum-dome-roofs/.

Response G1-78.224

The designs of the tanks mentioned in the comment are presented in Table 78.224-1. As presented in Table 78.224-1, all tanks are either domed external floating roof as requested in the comment or internal floating roof storage tanks, which are equivalent. Both meet BACT requirements. Moreover, as discussed in Response G1-78.217, emissions controls are required for all degassing and cleaning activities pursuant to SCAQMD Rule 1149. Therefore, no modification to the proposed project is necessary.

Table 78.224-1

New and Modified Storage Tanks in the Proposed Project

Tank	Capacity (bbl)	Tank Type
80060	80,000	Convert to IFR
80067	80,000	Convert to IFR
80079	80,000	Existing IFR
300036	300,000	Proposed IFR
300037	300,000	Proposed IFR
Carson Crude Terminal	6 – 500,000	Proposed Domed EFR

Note: IFR = Internal Floating Roof; EFR = External Floating Roof

See Response G1 -78.217, regarding degassing requirements.

Comment G1-78.225

VII. HAZARD IMPACTS WERE UNDERESTIMATED AND NOT MITIGATED

The DEIR evaluated the consequences of accidents at several units at each facility, as summarized in Table6. The DEIR characterizes the analyses in Table 7 as a worst case analysis. The DEIR also asserts that the Project "will not introduce the use of new flammable substances or hazardous materials that are not currently used at the Refinery…" Thus, it asserts that "no new sources of accidental releases of new hazardous materials would be present at the Refinery."[317] These assertions are incorrect. G1-78.225

Table 7.
Maximum Hazard Distance for
Maximum Credible Events in Each Process Unit[318]

Unit	Injury Threshold	Distance to Hazard (feet)		Hazard (Projected/ Existing)
		Projected	Existing	
Carson Operations				
51 Vacuum Unit	LFL	150	155	Flash Fire
Alkylation Unit	LFL	360	585	Flash Fire
HCU	30 ppm	1245	1250	Toxic (H_2S)
Mid-Barrel Distillate Treater	1,600 Btu/(hr ft^2)/ 30 ppm	275	400	Torch Fire/ Toxic (H_2S)
Naphtha HDS	LFL	865	1035	Flash Fire
Naphtha Isomerization	LFL	665	530	Flash Fire*
LHU	LFL	600	585	Flash Fire
Wet Jet Treater	LFL	205	DNCE[(b)]	Flash Fire
New Crude Tanks	1,600 Btu/(hr ft^2)	340	DNCE	Pool Fire*
Wilmington Operations				
FCCU	Hazards eliminated due to unit shutdown			
HTU-1/2	LFL	1170	1065	Flash Fire
HTU-4	Modifications do not affect hazard zone			
CRU-3	30 ppm	1595	2190	Toxic (H_2S)
PSTU HCU	30 ppm LFL	1085 1320	2190[(c)] 1450	Toxic (H_2S) Flash Fire
SARP	3 ppm	1905	DNCE	Toxic (SO_2)*
Replace Crude Tanks	1,600 Btu/(hr ft^2)	265	190	Pool Fire
Other				
Interconnecting Pipelines	LFL	380	DNCE	Flash Fire*
LPG Rail Car Unloading	1.0 psig	1,700	1,700	BLEVE

G1-78.225
cont'd.

[317] DEIR, p. 4-52.
[318] DEIR, Table 4.3-2.

Response G1-78.225

The reference to Table 6 in the first sentence of the comment should have been Table 7. The Refinery currently processes crude oil into a variety of products, most of which have flammable characteristics. As explained in Master Response 9, the proposed project does not introduce new chemicals that have different flammable characteristics than those currently in use. Therefore, the statements as quoted from the DEIR are correct. The flammable characteristics of the materials handled in each of the proposed new or modified process units were evaluated using the same injury threshold (i.e., ERGP-2 levels) to establish the worst-case potential hazard (e.g., the potential to form a flammable vapor cloud). As explained in Response G1.78-114, the maximum allowable vapor pressure was used to analyze the worst-case impacts. Consistent with air quality analysis of the proposed project, the maximum allowable vapor pressure was used in the hazard analysis, where appropriate, to determine the worst-case potential hazard impacts.

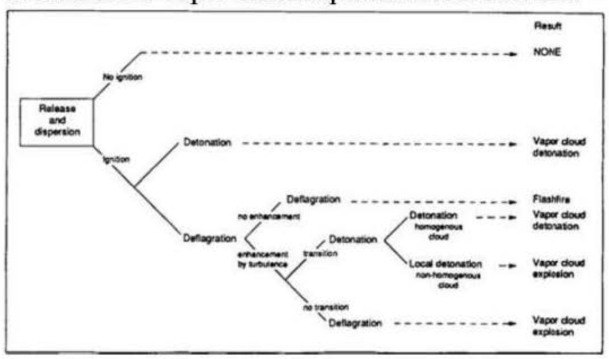
Comment G1-78.226

A. Worst Case Accident Was Not Evaluated

The types of accidents that could occur when a flammable material is released and an ignition source is encountered are summarized in the event tree in Figure 12. The EIR failed to consider most of these possible scenarios. Rather, the DEIR asserts without any supporting analysis that there are certain "worst-case scenarios" for the modified process units.[319] The DEIR fails to document the process used to select these scenarios, preventing meaningful public review. Thus, the DEIR fails as an informational document.

G1-78.226

Figure 12.
Event Tree for Vapor Cloud Explosions and Flash Fires[320]



[319] DEIR, Appx. C, Table 4-1.

[320] Center for Chemical Process Safety, Guidelines for Evaluating the Characteristics of Vapor Cloud Explosions, Flash Fires, and BLEVEs, 1994, Figure 2.1.

Response G1-78.226

The Worst-Case Consequence Analysis for the proposed project (see FEIR Appendix C) was performed by Quest Consultants Inc., a firm that specializes in analyzing and addressing process safety and risk associated with hazardous materials. Consequence analysis involves evaluating many factors at various locations throughout a unit (e.g., individual stream composition, temperature, pressure, line sizes, feed rates, etc.) to determine the potential release scenarios and event trees. Each piece of new equipment and unit modifications were evaluated for multiple events, with only the maximum or worst-case events being reported in the DEIR. Potential impacts for other events would produce less impacts. As explained in Section 4.3.2.1, the CANARY model was used to perform the consequence analysis. The overall analysis incorporates event trees to generate the worst-case consequence analysis.

Crude oil is a flammable material, which has a Lower Flammable Limit (LFL, a vapor concentration that when mixed with air allows the vapor/air mixture to burn). The LFL allows analysts to compare the potential impacts of different flammable materials such as methane, propane, and butane (pure components) and mixtures of flammable materials such as natural gas, gasoline, fuel oil, and crude oil (mixtures of components). There were no new flammable hazards introduced to the Refinery by the proposed project because the same range of flammable substances are expected to be used as are currently used and the flammable materials (a wide range) were all evaluated on the same basis: the potential to form a flammable vapor cloud.

For refinery operations, one factor that influences the formation and behavior of a flammable cloud is the pressure and temperature of the material before it is released. If the material is at near-atmospheric pressure and temperature and a release occurs (such as a release from a storage tank), a pool of liquid will form and the vapor generated and located directly over the pool may be flammable (dependent on atmospheric conditions). If this vapor were to ignite, a pool fire would be present, but no appreciable overpressure would be generated. A small pressure wave may form such that a person could hear the vapor burning, but the overpressure wave would not be significant and would not reach a damaging level for people or equipment outside the radiant heat zone.[199]

If the material is at an elevated temperature and/or pressure, such as may be the case within a process unit, the material may partially flash and generate a flammable cloud composed of vapor and small liquid droplets (an aerosol). The total mass of material that is at or above the LFL defines how much material is available to be consumed in fire should an ignition source be reached. The ignition of this type of release can result in a torch fire and possibly an accompanying pool fire. In the cases where these potential fires could occur, they were both evaluated when modeling the Worst Case Consequence Analysis (see Section 3.3.1 of the DEIR and 4.3.2 of the FEIR).

Vapor cloud explosions were also evaluated, but the extent of damaging levels of overpressure (defined as overpressure at or greater than 1 psi) were always smaller than the fire radiation extent (from a pool or torch fire) and/or the outer boundary of the LFL (defines the flash fire extent). Thus, explosion overpressure events that generate overpressure levels greater than 1 psi were analyzed but did not generate the largest impacts, thus they do not show up in a list that defines the 'Maximum Hazard Distance" (see Table 4.3-2 of the FEIR). Table 4.3-2 and Appendix C have been revised to present the injury threshold for the LPG Rail Car Unloading that was evaluated in the model (i.e., a thermal radiation of 1,600 $Btu/(hr \cdot ft^2)$), which is generated by a BLEVE fireball. The FEIR Table 4.3-2 is the result of hundreds of calculations. Only those generating the largest potential impacts are listed.

Comment G1-78.227

The DEIR evaluated either a flash fire or a pool fire at all tanks, processing units, and pipelines, except the mid-barrel distillate treater, where it evaluated a torch fire. A pool fire occurs when a flammable liquid forms a puddle on the ground and catches on fire. See Figure 13. It is contained to the area where the spill occurs. If a flammable spill forms a vapor cloud that encounters an ignition source, the vapor cloud can catch fire and burn rapidly in what is called a "flash fire." A "torch" fire results from the rupture of a pipeline followed by ignition. These fires do not represent a worst case.[321] In other words, the DEIR selected accidents that are contained and do not spread to surrounding equipment or cause explosions.

G1-78.227

[199] Gugan, 1979. Unconfined Vapor Cloud Explosions, Gulf Publishing Company, 1979.

Figure 13:
Pool Fire

[321] Thomas Steinhaus and others, Large-Scale Pool Fires, Thermal Science Journal, v.11, no. 3, 2007; Available at: http://www.doiserbia.nb.rs/img/doi/0354-9836/2007/0354-98360702101S.pdf.

G1-78.227 cont'd.

Response G1-78.227

The analysis presented in the DEIR included multiple scenarios, but only reported the maximum impact or worst-case results (see Section 4.3 and Appendix C of the FEIR). The comment provided no evidence to contradict the analysis presented in the DEIR.

The comment suggests that a vapor cloud could form from a spill and then expand into other areas and involve other equipment. If a vapor cloud formed from a pooled liquid spill and expanded into other areas, it would be considered an unconfined event (as opposed to a confined vapor cloud forming inside a structure or pieces of equipment). The equipment most susceptible to an overpressure wave would be equipment that is operated at ambient temperature and pressure, (e.g., storage tanks). In order to damage a storage tank to the extent that it will lose integrity, a vapor cloud explosion overpressure of 3.0 to 4.0 psi would be required.[200] An unconfined vapor cloud generated from a pool of crude oil would cause a peak overpressure of approximately 0.4 psi. As such, an unconfined vapor cloud explosion has insufficient overpressure to damage adjacent storage tanks to cause a loss of integrity and become involved in the incident. Process equipment includes pressure vessels that operate at elevated temperatures and pressures well over atmospheric conditions, have thicker walls, and are less susceptible to overpressure than atmospheric storage tanks. Therefore, process equipment would not be damaged from an unconfined vapor cloud explosion.[201]

[200] Gugan, 1979. Unconfined Vapor Cloud Explosions, Gulf Publishing Company, 1979. Table 3 lists rupture of oil storage tanks would occur at 20.7 kPa to 27.6 kPa or 3.0 psi to 4.0 psi.

[201] Gugan, 1979. Unconfined Vapor Cloud Explosions, Gulf Publishing Company, 1979. Table 3 lists rupture of oil storage tanks would occur at 69.0 kPa or 10.0 psi.

Thus, the DEIR reported the maximum impact or worst-case results, which in many cases is a flash fire (see DEIR Table 4.3-2). Appendix C has been revised to clarify the number of potential hazard scenarios analyzed.

Comment G1-78.228

A vapor cloud explosion is one of the most dangerous and destructive explosion that could result. These events result from the sudden release of a large quantity of flammable vapor, such as loss of tank containment, which could occur during a seismic event. The resulting vapor is dispersed throughout the general area while mixing with air. If the mixture encounters an ignition source, a vapor cloud explosion occurs. An example of a vapor cloud explosion is shown in Figure 14. In this vapor cloud explosion, triggered by backfire from an idling diesel pickup truck, 15 were killed and 180 injured.[322] Many ignition sources are present in a refinery, from idling vehicles to sparks generated during maintenance.

G1-78.228

Figure 14: BP Texas City Vapor Cloud Explosion

G1-78.228 cont'd.

[322] U.S. Chemical Safety and Hazard Investigation Board, Investigation Report, Refinery Explosion and Fire, BP Texas City, Texas, March 23, 2005, Report No. 2005-04-I-TX, March 2007; Available at: http://www.csb.gov/assets/1/19/csbfinalreportbp.pdf.

Response G1-78.228

Figure 14 in the comment is a photograph of a fire following a vapor cloud explosion associated with a process unit at a Texas Refinery (Texas City). The comment has mixed a discussion on potential storage tank releases with potential process unit releases, like the one shown in the photograph. The potential release scenarios are not the same because crude oil storage tanks typically operate at atmospheric conditions (ambient temperature and pressure) while process units operate at higher temperatures and pressures. Therefore, the potential release hazards are not the same.

The comment suggests that loss of tank containment could result in the "…sudden release of a large quantity of vapor, …" that would be "…dispersed throughout the general area…". The only tanks included in the proposed project are crude oil storage tanks, and the comment does not reflect the potential hazards that could be associated with loss of crude oil storage tank containment (i.e., a tank release). As explained below, any release from an atmospheric storage tank is expected to be captured in the bermed containment area,. This is because the containment area must conform to regulatory requirements to adequately contain the volume of the storage tank plus additional capacity to accommodate storm water.[202] The area of the Refinery where storage tanks are located, often referred to as a tank farm, is located away from processing units (see DEIR Figures 2-14 and 2-15). The comment describes a scenario where a large quantity of flammable vapor released from a storage tank during an earthquake. The proposed storage tanks will be equipped with floating roofs that rest on the liquid surface of the crude oil, which do not have a vapor space above the liquid surface where flammable vapors would be contained. (It should be noted that this is different than what could occur in a fixed roof tank). As such, a breach of the storage tank would produce a liquid release into the containment berm, not a vapor release.

The volatile fraction of the liquid would form flammable vapors above the pool. The expected hazard from a contained release of liquid material from a storage tank is a pool fire where the vapors above the liquid ignite. As presented in DEIR Table 4.3-2, the pool fire presents the greatest impact. Flash fires from vapor clouds igniting were analyzed for operating process units and were determined to be the worst-case scenario for some process units (see Table 4.3-2 of the FEIR).

As a result of the investigation into the Texas City incident, voluntary safety procedures including siting offices for personnel not essential to process unit operations away from operating process units have been implemented throughout the refining industry including the Refinery. Safety systems in place at the Refinery are described in Section 3.3.6 of the DEIR.

Comment G1-78.229

A BLEVE is also much more dangerous and destructive than the fire scenarios evaluated in the DEIR. A BLEVE occurs when a vessel containing a superheated liquid catastrophically fails, usually as a result of external fire exposure (i.e., a pool fire under the vessel or a jet- or torch-type fire impinging on the vessel wall).[323] In contrast to a pool fire or a vapor cloud explosion, the liquid within a tank does not have to be flammable to cause a BLEVE. An external fire around a tank or LPG rail car, for example, can heat the tank contents above its boiling point, resulting in an explosion.[324] The DEIR evaluated a BLEVE for LPG railcar unloading, but not for any other component of the Project. The new tanks within or adjacent to existing tank farms present opportunities for a BLEVE. G1-78.229

[323] Michael W. Roberts, Analysis of Boiling Liquid Expanding Vapor Explosion (BLEVE) Events at DOE Sites, 2000; Available at: http://efcog.org/wp-content/uploads/Wgs/Safety%20Working%20Group/_Nuclear%20and%20Facility%20Safety%20Subgroup/Documents/Analysis%20of%20Boiling%20Liquid%20Expanding%20Vapor%20Explosion%20(BLEVE)%20Events%20at%20DOE%20Sites.pdf.

[324] http://link.springer.com/article/10.1007/s11668-010-9360-9#page-2.

[202] U.S. EPA Spill Prevention, Control, and Countermeasures, https://www.epa.gov/oil-spills-prevention-and-preparedness-regulations.

Response G1-78.229

While the comment correctly states that the liquid inside a tank does not have to be flammable to cause a Boiling Liquid Expanding Vapor Explosion (BLEVE), a BLEVE can only occur when the pressure in the vessel exceeds the capacity of the vessel to contain that pressure.[203] Due to this over-pressure requirement and the requirement that the temperature in the vessel corresponds to an elevated temperature at the failure pressure to cause a BLEVE, a vessel failure could only be due to a BLEVE if it is isolated from the other pipes and vessels nearby. In other words, a vessel must be shut in for a BLEVE to occur. Thus, a distillation column, reactor, separator, etc. cannot BLEVE as the pressure can be relieved out of the pipes leading in/out of the vessel. This requirement alone restricts the application of a BLEVE to what are commonly called pressure vessels (railcars, tank trucks, and pressurized storage vessels).

Because pressure vessels have safety devices to prevent over-pressure (pressure relief valves) BLEVEs do not occur frequently. The pressure relief valves on pressure vessels are designed to accommodate an increase in pressure in the vessel from the heat from a pool fire below the vessel (i.e., the pressure relief valve will release the pressure to prevent a BLEVE). If a pressure vessel is involved in a BLEVE, the safety equipment may have been damaged (e.g., the pressure relief valves may have been damaged). This is more likely to occur in railcars and tank trucks because they are mobile sources which could be subject to transportation accidents, as opposed to stationary pressure vessels. The pressure relief valves may be compromised in a transportation accident and if a fire encroaches on the vessel, it may BLEVE if the pressure in the vessel exceeds the ability of the vessel to contain that pressure.

BLEVEs are rare even during pressure vessel transportation. Crude oil is stored in atmospheric (or near-atmospheric) storage tanks, not pressurized tanks. Therefore, if a crude oil storage tank failed, it would fail at low pressure and the primary result would be a pool fire. A BLEVE cannot occur in an atmospheric or near-atmospheric, non-pressurized tank such as a crude oil storage tank, regardless of the tank contents.

An LPG railcar (a pressurized tank car) BLEVE in the current and post-project setting was evaluated in the DEIR, since it was the only pressure vessel associated with the proposed project (see FEIR Section 4.3.2.1) that could have a vulnerability zone[204] that extends beyond the Refinery boundary.

[203] Guidelines for Evaluating Process Plant Buildings for External Explosions and Fires, Appendix A, http://onlinelibrary.wiley.com/doi/10.1002/9780470937938.app1/pdf.

[204] The vulnerability zone is the area within which exposed persons are expected to be harmed to a degree that impedes relocating to outside the zone or structures and equipment would have substantial damage from an event.

Comment G1-78.230

The DEIR admits that "[t]he greatest threat to off-site receptors could occur from a vapor cloud explosion (release, dispersion, and explosion of a flammable vapor cloud), or a confined explosion (ignition and explosion of flammable vapors within a building or confined area)."[325] However, in spite of this admission, the DEIR fails to evaluate these types of accidents except for LPG railcar loading. G1-78.230

Vapor cloud explosions and BLEVEs are more likely at the site post-Project than during the baseline, due to the volatility of Bakken crude. Further, vapor cloud explosions and BLEVEs are generally likely at the Los Angeles Refinery due to the proximity of many sources of ignition, e.g. busy roads, and the high density of tanks and process units that could be engulfed by the vapors. G1-78.230 cont'd.

The release of a flammable material, such as Bakken crude, may result in a vapor cloud explosion, fireball or BLEVE, which could result in much more significant consequences than the accident scenarios that were evaluated in the DEIR. In a vapor cloud explosion, the vapors from a crude oil spill could engulf adjacent tanks or process units and ignite, presenting greater impacts than considered in the EIR.[326]

[325] DEIR, p. 3-19.
[326] *See* photographs of vapor cloud explosions at:https://www.google.com/webhp?sourceid=chrome-instant&ion=1&espv=2&ie=UTF-8#q=photographs+of+vapor+cloud+explosions.

Response G1-78.230

The comment provided no evidence to contradict the analysis presented in the DEIR. The analysis presented in the DEIR included multiple scenarios, but reported the maximum impact results that are possible based on the specific characteristics of the Refinery and the proposed project (see DEIR Table 4.3-2).

Response G1-78.229 explains why a pool fire was evaluated for potential crude oil (including Bakken crude oil) storage tank failures. The footprint or impact zone of a vapor cloud explosion (VCE) that could possibly occur from the release of liquid crude oil from a storage tank would be smaller than the footprint of a flash fire that could ignite above and around a pool of crude oil. Therefore, the pool fire (flash fire) evaluated in the DEIR has the maximum potential impacts.

The primary difference between a vapor cloud explosion and a flash fire is that an explosion involves a pressure or shock wave having enough energy to cause damage. A VCE could only occur if a flammable vapor cloud (or portion of a flammable vapor cloud) were to be located in a congested or confined area. In a confined area such as a process unit with a maze of small diameter piping, once an ignition source is found, the flame front from the ignited vapor cloud could accelerate because the obstacles induce turbulence that allows the flame to accelerate.[205]

Process units are not located in the vicinity of the proposed storage tanks at either the Carson or Wilmington Operations; the proposed storage tanks will be located in tank farms, in unconfined areas in the vicinity of existing storage tanks. As explained in Response G1.78-227, unconfined vapor cloud explosions are not expected to cause nearby tankage or units to become involved in

[205] Guidelines for Evaluating Process Plant Buildings for External Explosions and Fires, Appendix A, http://onlinelibrary.wiley.com/doi/10.1002/9780470937938.app1/pdf.

a release scenario because the potential overpressure wave would be insufficient to cause damage to adjacent structures or equipment. The proposed project evaluated the storage tanks using the highest vapor pressure allowed for the material to be stored. The process units were evaluated and compared to baseline conditions in the existing units. The worst-case consequences are presented in the DEIR. Response G1-78.229 addresses the potential for a BLEVE.

In addition, the Refinery is equipped with fire protection systems to isolate incidents and protect adjacent equipment. The fire protection systems would further prevent adjacent equipment from becoming involved in a fire resulting from a crude oil release. Therefore, the DEIR evaluates the worst-case consequences from a crude oil release.

Comment G1-78.231

The two new 300,000 bbl storage tanks at Wilmington, for example, are within an existing tank farm.[327] Similarly, the six new 500,000 bbl storage tanks at Carson are across Sepulveda Boulevard from the main Carson tank farm.[328] If the contents of one of the new tanks were lost, such as might occur during a seismic event, and a vapor cloud were formed, it could engulf adjacent tanks. If the resulting vapor cloud encountered an ignition source, e.g., from traffic along Sepulveda Boulevard or from welding at an adjacent tank, a vapor cloud explosion could result. The risk of these types of events at the new tanks are significantly greater than at existing crude oil tanks as the new tanks will store Bakken crude oil, which is much more volatile and flammable than crude oils stored in the baseline. G1-78.231

[327] DEIR, Appx. C, Figure 2-1.

[328] DEIR, Appx. C, Figures 2-2/2-3.

Response G1-78.231

As explained in detail in Sections 2.5.3 and 2.5.4 and Appendix F of the DEIR, Master Response 9, and Responses G1-78.94 and G1-78.122, crude oils with various properties, including Bakken crude oil, are blended at the Refinery today. The proposed Wilmington Operations replacement storage tanks are to be located in an existing tank farm and the expected maximum release impacts would not extend offsite (see DEIR Figure 4.3-1). The proposed Carson Crude Terminal storage tanks are to be located in an area adjacent to existing tanks to the north and south and in a vacant area and is not near the process units of the Refinery (see DEIR Figure 2-16).

The release from a crude oil storage tank would result in a pool of liquid within the required containment berm. Therefore, the hazard with maximum impacts is a pool fire. This includes the potential ignition of the vapors that volatize from the pool which are above the lower flammable limit. As the vapors from the pool are dispersed, the vapors become too diluted to burn. Pool fires were analyzed in the DEIR for the proposed storage tanks using the properties of the lightest crude oil permitted to be stored in the tanks which represents a worst-case scenario because it generates the largest vulnerability zone.

As explained in Response G1-78.227, vapor cloud explosions are not expected to cause nearby tankage or units to become involved in a release scenario because the potential overpressure wave would be insufficient to cause damage to adjacent structures and equipment. Vapor cloud explosions were evaluated and determined to have a smaller impact than a potential pool fire. The comment provided no evidence that a vapor cloud explosion would produce a larger impact than the pool fire analyzed in the DEIR.

Comment G1-78.232

As another example, the Project includes an interconnecting pipeway between the Wilmington and Carson Operations. The new pipeway, comprising up to 15 pipelines, will be routed under two major roadways and above ground on pipe racks or ground level pipe supports, in the same corridors as existing pipelines.[329] These pipelines will transport gasoline and gasoline blending components, gas oil, crude oil, butylene, propylene, and LPG between the Carson and Wilmington Operations.

The DEIR asserts that the proposed pipelines would have hazards of approximately the same magnitude as the existing pipelines, since the proposed and existing pipelines will convey similar materials at similar operating temperatures and pressures.[330] The DEIR is incorrect.

G1-78.232

The proposed and existing pipelines will not have similar hazards. The Project will increase the number of pipelines in the same corridors. Thus, it will cumulatively increase the potential hazards of an accident as an accident at one of the pipelines could involve the others. A pipeline break, for example, triggered by an earthquake, could release gasoline. This would create a vapor cloud that could ignite, involving not only other pipelines in the corridor, but other nearby facilities, such as tanks and process units.

In sum, the DEIR has failed to disclose the basis for selecting accident scenarios, failed to disclose critical chemical and physical characterization data for the materials involved in the accidents, failed to select worst-case scenarios, and failed to disclose the true consequences of accidents at the Refinery. Thus, the DEIR fails as an informational document.

G1-78.232 cont'd.

[329] DEIR, p. 4-54, Appx. C, p. 8.

[330] DEIR, p. 4-54.

Response G1-78.232

The worst-case consequence analysis in the DEIR evaluates the impacts of a single release of a pipeline in the Interconnecting Piping between Carson and Wilmington Operations. In a pipe corridor that contains multiple lines carrying commodities with various properties, such as the proposed project, the worst-case consequence is determined by analysis of the line with the maximum potential impacts (e.g., the line with the highest vapor pressure or most volatile commodity or combination thereof).[206] In other words, if there are multiple lines in the same pipeline corridor, should there be a concurrent failure of multiple lines the impact will be defined by the vulnerability zone of the individual line with the largest potential vulnerability zone. The vulnerability zones are not additive; rather the largest potential vulnerability zone encompasses

[206] Attachment H, Quest Consultants Memoranda

the vulnerability zones of the other lines. For the proposed project, the LPG transfer line in the proposed pipeline bundle was analyzed and found to be the line with the largest vulnerability zone.

The failure of any particular pipeline is dependent on the physical and operating conditions of the individual pipeline. The Basin contains hundreds of miles corridors with multiple pipelines carrying various materials in an area that experiences earthquakes. As further described below, past experience contradicts the unsupported claim in the comment that multiple, co-located pipelines would fail, concurrently.

Quest Consultants Inc. (Quest), who specialize in hazards analysis and performed the Worst-Case Consequence Analysis for the proposed project, performed a data search of pipeline releases caused by earthquakes in California from publicly available data from the PHMSA.[207] The data from the PHMSA website was filtered to isolate releases caused by earthquakes from 1970 to near-present day. Releases that occurred on the same date and in the approximate same location were identified and evaluated. Review of the incidents revealed that multiple releases occurred in Los Angeles during the Northridge earthquake on January 17, 1994. Pipeline releases from the Northridge earthquake were spread throughout Los Angeles, but there is no record of two pipeline releases that occurred at locations near enough that the hazards overlapped. Each release produced an independent hazard (i.e., one release did not cause another release). Thus, review of approximately 50 years of pipeline release data provides no evidence that two (or more) pipelines, located next to each other, in a common corridor, have both failed concurrently during an earthquake.

It is important to note that the design standards used for the proposed project pipelines meet and exceed current pipeline standards (see DEIR Section 2.7.3.1). The proposed project pipelines are designed in accordance with: American Lifeline Alliance design criteria for earthquake interaction[208], ASME Standard B 31.4, and 49 CFR Section 193.

A geotechnical review of the site was preformed and verified that the pipeline will not cross or approach any State identified earthquake faults that could damage the pipelines. The closest faults are splays of the Newport-Inglewood and the Palos Verde faults (see DEIR Appendix A, pages A-66 and A-67). The general area is underlain with alluvial type soils with a high ground water table that could liquefy during a seismic event. As long as liquefied soils do not flow, they are not a hazard to the pipelines. Because the pipelines do not cross or run near a change in elevation, liquefied soils could not become unstable and flow in a direction that would involve the pipelines.

The analysis evaluated, among other things, the flammable properties of materials, temperatures, pressures, and line sizes to determine the worst-case impacts from a release. Responses G1-78.227 and G1-78.228 explain why VCEs will not occur in an unconfined area such as a tank berm. Similarly, VCEs will not occur in the pipeways of the Refinery that are also unconfined.

[207] Attachment H, Quest Consultants Memoranda

[208] American Lifeline Alliance design criteria for earthquake interaction, http://www.americanlifelinesalliance.com/Products_new3.htm, and http://www.americanlifelinesalliance.com/pdf/Update061305.pdf.

The analysis in the DEIR Section 4.3.2.3 includes a flash fire hazard from the interconnecting pipeline as the worst-case hazard associated with the pipelines.

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1. Accident History at the Refineries Not Provided

The DEIR did not review the history of accidents at refineries in general or at the Carson and Wilmington Operations. See, for example, the compilations of major accidents in Lees' seminal *Loss Prevention Handbook.*[331]

The starting point for a hazard analysis should be a review of the history of accidents at the subject refineries and refineries in general, particularly in this case as the subject refineries were built in 1919 and 1923.

There have been many serious accidents at both the Carson and Wilmington Refineries, some of which were recently reviewed by the Los Angeles Times.[332] Further, more serious accidents have occurred at other refineries than analyzed in the DEIR, including at Tesoro refineries elsewhere.[333]

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[331] Dr Sam Mannan, Lees' Loss Prevention in the Process Industries: Hazard Identification, Assessment and Control, Fourth Edition, 2012, Appendix 1, Case Histories.

[332] Los Angeles Times Staff, South Bay Oil Refineries: A History of Destructive Explosions, Los Angeles Times, February 18, 2015; Available at: http://www.latimes.com/local/lanow/la-me-ln-south-bay-oil-refineries-history-explosions-20150218-story.html.

[333] See, e.g., Chevron Refinery Fire, January 28, 2015; Available at: http://www.csb.gov/chevron-refinery-fire/; Tesoro Refinery Fatal Explosion and Fire, May 1, 2014; Available at: http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/; Valero Refinery Propane Fire, July 9, 2008; Available at: http://www.csb.gov/valero-refinery-propane-fire/; BP America Refinery Explosion, March 20, 2007; Available at: http://www.csb.gov/bp-america-refinery-explosion/; Motiva Enterprises Sulfuric Acid Tank Explosion, August 28, 2002; Available at: http://www.csb.gov/motiva-enterprises-sulfuric-acid-tank-explosion/; Tosco Avon Refinery Petroleum Naphtha Fire, March 21, 2001; Available at: http://www.csb.gov/tosco-avon-refinery-petroleum-naphtha-fire/.

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Historical incidents at the Refinery are not indicative of future events because Refinery safety regulations have become increasingly restrictive over time. In addition, the ownership of the refineries has changed in that operating performance by prior owners is not indicative of future performance. Therefore, historical incidents are not considered in the hazard consequence analysis.

The hazard analysis in the DEIR considers the consequences of a catastrophic event based on pipeline design and operating conditions. The analysis in the DEIR fully analyzed the potential worst-case impacts from a potential incident due to the implementation of the proposed project. The frequency of incidents is not considered in a consequence analysis. The determining factor in a consequence analysis as to whether an incident is significant is whether an off-site receptor will be severely injured by an incident, should an incident ever occur. The inclusion of frequency in the hazard impact analysis would require establishing an acceptable number or rate of occurrences. The SCAQMD considers the impacts of any occurrence, not a combination of the consequence and some predetermined acceptable frequency of occurrence, to determine significant impacts.

The absence of frequency in the significance determination provides a conservative approach to evaluating the proposed project's impacts. An analogy is the lottery. The likelihood of winning is very low, so a significance determination based on the chance of winning would be that winning is not significant. However, if the lottery is won, the winner most definitely has a significant life changing event. In the case of hazards, worst-case impacts are analyzed in the DEIR regardless of the likelihood of occurrence.

Footnote 333 of the comment provides a number of examples of past incidents at U.S. refineries, for example, the 2012 Chevron Richmond Refinery Incident. This response explains why the cited incidents do not indicate a likelihood of similar incidents as a result of the proposed project. As explained in Response G1.78-111, the Chevron Richmond incident was actually caused by improper metallurgy in the section of piping in the crude unit that consequently failed due to sulfidic corrosion which caused the fire. As with all major incidents at U.S. refineries, findings/lessons learned from the Chevron Richmond incident have been made available to the refining industry. The Refinery has evaluated its equipment (e.g., crude units) for the potential issues that caused the Chevron incident and confirmed that those conditions do not exist at the Refinery (see Response G1-78.111).

In addition to industry-driven process safety improvements, CalEPA and CalOSHA have proposed changes to CalARP and Process Safety Management (PSM) regulations to improve community and worker safety in response to the Chevron Richmond incident. The comment period for the proposed, revised CalARP and PSM regulations closed on September 15, 2016. Many comments were submitted on the proposed regulations to CalEPA. In response to those comments, CalEPA and CalOSHA will potentially be making additional revisions to the regulations. Until the regulatory process is complete, it is premature to anticipate future CalARP and PSM regulatory requirements. However, the Refinery will comply with the final revised regulations.

Additional details on the other incidents cited in Footnote 333 are provided below:

Tesoro Anacortes Refinery Incident – see Response G1-78.234.

Valero Refinery Incident - The incident that occurred in 2007 at the Valero McKee Refinery is not relevant to the proposed project. The incident occurred at Valero's Propane De-asphalting Unit, and no such unit exists at the Refinery. The cause of the Valero incident was freeze-related failure of high-pressure piping at a control station that had not been in service for approximately 15 years and was not isolated or freeze protected.[209] Additionally, based on the Refinery's location in southern California, there is no likelihood of freeze related conditions.

BP Refinery Incident - The incident that occurred in 2005 at the BP Texas City Refinery and potential risks associated with the incident have been addressed at the Refinery. Key incident findings per the CSB report that have been addressed by the Refinery include facility

[209] Valero Refinery Propane Fire Final Report, July 9, 2008, http://www.csb.gov/valero-refinery-propane-fire/.

siting/trailer siting, fatigue standard, and conducting a process safety culture survey.[210] The Refinery addressed facility siting issues at its Carson and Wilmington Operations by locating office buildings outside potential process unit blast hazard zones and by installing blast-resistant modules (buildings) in process areas. The Refinery implemented a worker fatigue standard, and conducted and implemented action items resulting from process safety culture surveys at Carson and Wilmington Operations. Action Items included process safety awareness classes for workers, restrict driving of personal vehicles into the Refinery, and facility siting (prohibit occupancy from certain buildings and restrict new buildings meant for occupancy to certain locations; limit canopy locations that allow people to gather (e.g., for meal) to certain locations, and retrofit certain existing occupied buildings to be blast resistant or install new blast resistant modules for occupancy.)

Motiva Enterprises Incident - The incident that occurred in 2001 at the Motiva Enterprises Delaware City Refinery has been evaluated by Tesoro and potential risks associated with the incident have been addressed at the Refinery. The Motiva incident occurred due to a mechanical integrity issue with a tank and an inadequate management of change (MOC) process.[211] To prevent this type of incident from occurring, the Refinery has a robust Mechanical Integrity Program. A formal deferral process must be conducted and documented prior to deferring any mechanical integrity items at the Refinery, including tank inspections. This process includes, but is not limited to, a "risk assessment" or review of the hazards, evaluation of existing safeguards, and management approval prior to deferring any tank inspections. Additionally, per the Refinery's MOC work process, a change in tank service requires a formal MOC team review by various disciplines (Engineering, Operations, Maintenance, Safety and Environmental Departments).

Tosco Avon Refinery Incident - The incident that occurred in 1999 at the Tosco Avon Refinery has been evaluated by Tesoro and potential risks associated with the incident have been addressed at the Refinery. The Tosco incident was caused by the removal of leaking piping connected to a 150-foot-tall fractionator tower while the process unit was in operation.[212] To prevent this type of incident from occurring, the Refinery has a "Leak Protocol" standard that provides guidance to be used in the decision making process when a leak is discovered. If a leak detection situation occurs similar to the 1999 Tosco incident, a unit shutdown is the protocol that would be followed prior to removing the leaking line. Additionally, the Refinery's formal "Permit to Work" Maintenance planning work process requires a formal hazard assessment evaluation first, prior to initiating any work.

Several South Bay refinery incidents were cited in a Los Angeles Times article dated February 18, 2015:[213]

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[210] BP America Refinery Explosion Final Investigation Report, March 20, 2007, http://www.csb.gov/bp-america-refinery-explosion/.

[211] Motiva Enterprises Sulfuric Acid Tank Explosion Final Report, August 28, 2002, http://www.csb.gov/motiva-enterprises-sulfuric-acid-tank-explosion/.

[212] Tosco Avon Refinery Petroleum Naphtha Fire Final Report, March 21, 2001, http://www.csb.gov/tosco-avon-refinery-petroleum-naphtha-fire/.

[213] South Bay Oil Refineries: A history of destructive explosions, February 18, 2015, http://www.latimes.com/local /lanow/la-me-ln-south-bay-oil-refineries-history-explosions-20150218-story.html.

- The incident reported in the Los Angeles Times article that occurred in 2015 at the ExxonMobil Torrance Refinery (currently the Torrance Refining Company) is not relevant to the proposed project. The incident was caused by hydrocarbons that leaked into an energized FCCU electrostatic precipitator. The Refinery has a differently configured FCCU electrostatic precipitator compared to the ExxonMobil Torrance Refinery. The Refinery's electrostatic precipitator has instrumentation to detect hydrocarbon leakage that would immediately shut down the equipment and prevent an explosion such as the incident at the Exxon Mobil Torrance Refinery.

- The incident reported in the Los Angeles Times article that occurred in 1996 at the Texaco Wilmington Refinery (now the Wilmington Operations) was addressed and is not relevant to the proposed project because the proposed project does result in the circumstances that caused the incident. The cause of the 1996 Texaco Wilmington Refinery incident was a pipe elbow failure. The pipe elbow had unusual thinning (corrosion) caused by unbalanced flow and an inefficient water wash system. It was determined that the piping configuration was not well balanced and that flow of wash water that is needed for corrosion prevention was inadequate or did not reach all the piping components in the system. The investigation recommendations from this incident on balanced flow and effective water wash system design were adopted and implemented by the Refinery immediately after the incident.

- The incident reported in the Los Angeles Times article that occurred in 1994 at the Mobil Oil Torrance Refinery (currently the Torrance Refining Company) is not relevant to the proposed project because the proposed project will adhere to established procedures. The incident was caused by a hydrocarbon leak due to an improperly executed Pre-Startup Safety Review (PSSR) of a pipeline project and the improper isolation of a pipeline. The Refinery has a rigorous PSSR work process, specific to project-related work (i.e., Refinery activities that are not routine operations and maintenance), and requires a thorough field confirmation and review, prior to commissioning any project.

- The incident reported in the Los Angeles Times article that occurred in 1988 at the Mobil Oil Torrance Refinery (currently the Torrance Refining Company) is not relevant to the proposed project because the activity does not occur at the Refinery. The Mobil Oil incident was caused by using concentrated hydrogen peroxide to treat sludge that created an uncontrollable reaction. The Refinery does not use concentrated hydrogen peroxide to treat sludge.

- The incident reported in the Los Angeles Times article that occurred in 1985 at the Atlantic Richfield Carson Refinery (now Carson Operations) was addressed and the proposed project is not expected to create the circumstances that caused the incident because the proposed project has been specifically designed to prevent water carry over and corrosion. The incident involved a pipe failure caused by water carry over into a line which created corrosion. The findings/lessons learned on preventing water carry over and corrosion were applied to other similar piping installations at the Refinery to prevent similar failures.

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A 2010 fatal explosion and fire at the Tesoro refinery in Anacortes, Washington, led state regulators to cite the company for 39 "willful" and 5 "serious" violations of health and safety regulations. The Washington Department of Labor and Industries called this accident the "worst industrial disaster in the 37 years that L&I has been enforcing the state's workplace safety law.[334] The U. S. Chemical Safety Board concluded that the company's "safety culture" was a key factor in the accident:[335]

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KEY ISSUES

- INHERENTLY SAFER DESIGN
- TESORO PROCESS SAFETY CULTURE
- CONTROL OF NONROUTINE WORK
- MECHANICAL INTEGRITY INDUSTRY STANDARD DEFICIENCIES
- REGULATORY OVERSIGHT OF PETROLEUM REFINERIES

The 2010 accident at the Anacortes Refinery was attributed to Tesoro's "complacent" attitude towards flammable leaks and fires and failure to correct a history of recurring leaks, failure to maintain equipment, and a general "deficient refinery safety culture, weak industry standards for safeguarding equipment, and a regulatory system that too often emphasizes activities rather than outcomes."[336]

[334] Eric de Place, Tesoro: A Track Record of Pollution, Hostility to Workers, and Meddling in Politics, Sightline Institute, March 21, 2014; Available at: http://www.sightline.org/2014/03/21/tesoro-a-track-record-of-pollution-hostility-to-workers-and-meddling-in-politics/.

[335] U.S. Chemical Safety and Hazard Investigation Board, Investigation Report, Catastrophic Rupture of Heat Exchanger (Seven Fatalities), Tesoro Anacortes Refinery, Anacortes, Washington, April 2, 2010, Report 2010-08-I-WA, May 2014, Exhibit 35..

[336] CSB Investigation Finds 2010 Tesoro Refinery Fatal Explosion Resulted from High Temperature Hydrogen Attack Damage to Heater Exchanger, Available at: http://www.csb.gov/csb-investigation-finds-2010-tesoro-refinery-fatal-explosion-resulted-from-high-temperature-hydrogen-attack-damage-to-heat-exchanger/?SID=97.

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The comment references the Chemical Safety Board's (CSB) report on the 2010 Anacortes Refinery incident. The CSB's findings and recommendations regarding the Anacortes Refinery incident are based on the incident investigation and do not include a corporate-level assessment. Therefore, the CSB report concerning process safety culture were expressly limited to the Anacortes Refinery and do not apply to any other Tesoro refineries (see CSB Investigation referenced in the comment Footnote 335 at Section 1.2.2, paragraphs 18-19; Section 8.6). The Anacortes Refinery is not related to the proposed project in any way.

However, the following are responses to the "Key Issues" raised in the comment:

Inherently safer design – The April 2010 incident at Tesoro's refinery in Anacortes, Washington involved failure of a heat exchanger in the Naphtha Hydrotreater Unit ("NHT") as a result of a damage mechanism known as high temperature hydrogen attack ("HTHA").[214] Since the incident, Tesoro has increased the standard safe operating margin for equipment in hydrogen

[214] Chemical Safety Board (CSB), Report 2010-08-I-WA, May 2014, Section 1.2.1.

service below the Nelson Curve[215][216] to prevent corrosion and failure of equipment at the Anacortes Refinery and all other Tesoro refineries.

Tesoro Process Safety Culture – As explained above, the CSB report specifically identifies the Tesoro Anacortes Refinery when describing the process safety culture. The issue was thus isolated to the Anacortes Refinery. The AFPM, in association with the API, classified Tesoro in the top (First) quartile on process safety performance indicator benchmarking of U.S. refining companies. The First quartile ranking is the best refining industry performers. Tesoro has been in the First quartile since 2012.

Control of Non-routine Work - The Refinery is under an improved permit to work program that is more effective than the one that was in place at Anacortes in 2010. This newer permit to work program includes better hazard impact analysis.

Industry Standard Mechanical Integrity Deficiencies – Following the incident, the CSB found that the HTHA damage occurred under conditions that industry standards, at the time, indicated were not a risk.[217] As a result, CSB found that industry standards were not reliable and recommended that the API revise industry standards to incorporate findings/lessons learned from the incident.[218] The API Recommended Practice 941 – Steels in Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants has been revised since this incident. Tesoro implemented a mechanical integrity program and inspection strategy for equipment in potential HTHA service that implements API's Recommended Practice.

Regulatory Oversight of Petroleum Refineries –The California refining industry is highly regulated (see DEIR Section 3.3.7). Following the April 2010 incident, CalOSHA initiated a California Emphasis Program under which Program Quality Verifications ("PQV") were conducted in every California petroleum refinery, including the Carson and Wilmington refineries. During these PQVs, CalOSHA inspected and evaluated each refiner's procedures and practices for identifying and mitigating corrosion damage, including high temperature hydrogen attack, for heat exchangers in NHT units. In October 2010, CalOSHA reported its finding that all California refineries were properly managing corrosion risks in NHT units.

The Refinery completed a PQV in 2015 with only one process related citation. Specifically, an operator was unable to explain the function of a new gas monitor. To resolve the citation, Tesoro retrained all the Shipping and Handling operators who were previously trained on the system. The issue was specific to existing operators. New employees are trained on job specific duties including instrumentation and monitoring equipment.

Additionally, the AFPM, in association with the API, classified Tesoro in the top (First) quartile on process safety performance indicator benchmarking of U.S. refining companies. The First

[215] Chemical Safety Board, Report 2010-08-I-WA, May 2014, Figure 16.
[216] Nelson curves are commonly used to select the various grades of steels and the safe operating parameters (e.g., temperature and pressure).
[217] Chemical Safety Board, Report 2010-08-I-WA, May 2014, Sections 4.2.1 and 4.4.1.1.
[218] Chemical Safety Board, Report 2010-08-I-WA, May 2014, Sections 4.4.1.1 and 8.4.

quartile ranking is the best refining industry performers. Tesoro has been First quartile since 2012.[219]

Comment G1-78.235

2. Process Location Not Considered

The location of a process, such as the new tanks and pipelines in relation to other facilities is a key consideration in evaluating risks. The new tanks, for example, are within or adjacent to existing tank farms.[337] Further, the EIR fails to disclose the contents of the adjacent tanks or the process units, which must be known to assess the hazards they pose. An accident at one of the new tanks could generate a vapor cloud that would engulf one or more tanks in the adjacent tank farm, significantly increasing the impacts of an accident, or, alternatively, the vapor cloud from an accident in the

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adjacent tank farm could engulf the new tanks, resulting in significant impacts. If the vapor clouds from these types of events encountered an ignition source, a vapor cloud explosion or BLEVE could result.

Tank berms would not prevent the interaction between the new tanks and existing tank farms because vapor clouds would pass over the berm, from either the new tanks to the existing tank farms or vice versa. Further, it is well known that berms are frequently damaged in tank accidents,[338] which could spread the consequences of a tank accident into adjacent areas.

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[337] DEIR, Figures 4.3-1 and 4.3-2.

[338] Davies et al., Bund Effectiveness in Preventing Escalation of Tank Farm Accidents, October 1995.

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As explained in Response G1.78-227, vapor cloud explosions are not expected to cause nearby tankage or units to become involved in a release scenario because the potential overpressure wave would be insufficient to cause damage to adjacent structures. Contrary to the comment, a BLEVE cannot be generated by an atmospheric tank as explained in Response G1-78.229.

Tank containment berms are required for compliance with Spill Prevention Control and Countermeasure regulations (see DEIR Section 3.3.7.1.6). Berms must be designed to contain 110 percent or more of the volume of the largest storage tank. The reference cited in the comment is outdated. The incidents cited in the reference occurred between 1969 and 1988. Since that time, tank and berm design standards have improved the structural integrity of the installations. Current standards include, but are not limited to, seismic, metallurgy, leak detection, emissions, and method of construction (i.e., welded, not riveted seams, and the welds are inspected).[220] Berms must be engineered to contain the contents that may be released.[221]

[219] API, May 2016. Years: 2013-2015, Process Safety Events Survey, Benchmarking Report.

[220] API Standard 650, Welded Tanks for Oil Storage, Twelfth Edition, March 3013, Addendum 1, September 2014, Addendum 2, January 2016, Errata 1 January 2016, and Errata 2, December 2014.

[221] 40 CFR Part 112 – Spill Prevention Control and Countermeasure.

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3. Ignition Sources Not Considered

Vapor clouds generated by spilled flammable liquids, such as the imported crude oil, have the potential to ignite anywhere within their flammable limits if there is an ignition source. Ignition data is required to estimate risks but none is disclosed in the DEIR. There are many ignition sources at the site, including:[339]

- locomotives for LPG and coke trains on the local rail lines,
- traffic on the access road and traffic on adjacent heavily traveled public roadways,
- workers who smoke,
- hot surfaces,
- open flames as from welding,
- electric sparks from motors driving pumps and other equipment,
- suction of crude vapors into diesel engines and subsequent combustion,
- friction sparks, as from trains on the tracks and railcars jamming into each other during stops and starts,
- heaters and boilers, and
- increased flaring from new pressure relief valves that will tie into existing flares.

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[339] DEIR, p. 2-37, 2-38, 2-39, 2-43, etc.

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The type of ignition source has no bearing on the result of the consequence analysis. The consequence analysis prepared for the proposed project utilizes worst-case dispersion assumptions to generate the largest event that is ignited by an ignition source (see FEIR Section 4.3.2.1). In the case of a flammable vapor release, the worst-case would be either a torch fire or a flash fire. A torch fire could occur when a pressurized release ignites at the source of the release. If the release did not ignite at the source, a flammable vapor cloud could form and travel downwind. If the vapor cloud was exposed to an ignition source, a flash fire could occur. Both scenarios are analyzed and the DEIR presented the larger of the two impacts: radiant impacts from torch or flash fire (see DEIR Table 4.3-2).

In addition, the Refinery manages flammable materials routinely and has standard operating procedures and safety procedures to minimize fires. Examples include designating the Refinery a smoke-free facility, requiring hot work permits, and classifying areas where electrical equipment must be spark free.[222]

[222] Tesoro Refining and Marketing Company, LAR Carson Site Visitor Orientation Program DVD, Revised December 30, 2013.

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4. External Events Not Considered

The DEIR recognizes that external events, such as earthquakes and non-natural events, such as mechanical failure or human error can cause accidental releases.[340] The DEIR also recognizes that "The most significant potential geologic hazard is estimated to be seismic shaking from future earthquakes generated by active or potentially active faults in the regions."[341] However, the DEIR fails to consider the impacts of a major earthquake as a triggering event for accidents, arguing instead that "[p]ast experience indicates that there has not been any substantial damage, structural or otherwise to the Wilmington and Carson Operations as a result of earthquakes."[342] The DEIR fails to supply any support for this claim.

However, this is not a reasonable basis for excluding earthquake-induced accidents. First, experience is not a reliable indicator here as the only major earthquake in Long Beach on the nearest fault to the refinery occurred in 1933. The subject refineries were built in 1916 and 1923 and did not include most of the process units included in the hazard analysis as they had not yet been invented.[343] Second, the DEIR misrepresents the facts. The 1933 Long Beach earthquake caused significant damage in the surrounding area:[344] G1-78.237

> "**Areas of Past Liquefaction**
>
> In the Long Beach Quadrangle, numerous effects attributed to liquefaction were noted following the 1933 Long Beach earthquake including numerous leaks in gas lines, water mains broken, roads cracked, and displaced pavement (Barrows, 1974).
>
> Part of the Port of Los Angeles is situated in the southwestern most corner of the Long Beach Quadrangle. During the 1994 Northridge earthquake significant damage occurred to facilities near Berths 121 to 126 and at Pier 300 (Stewart and others, 1994, p. 135). Features that developed at these localities, such as lateral spreading, settlement, and sand boils, manifested liquefaction (see Plate 1.2)."

Berth 121 served the Carson facility in the baseline and will serve the combined Los Angeles Refinery. The six new 500,000 bbl tanks are nearby.

[340] DEIR, pp. 1-19, 3-18.

[341] DEIR, p. 4-106.

[342] DEIR, p. 4-106. See also p. A-64.

[343] DEIR, Appendix A, Table 2-4.

[344] Division of Mines and Geology, Seismic Hazard Zone Report for the Long Beach 7.5-Minute Quadrangle, Los Angeles County, California, 1998, p. 14; Available at: http://gmw.consrv.ca.gov/shmp/download/quad/LONG_BEACH/reports/longb_eval.pdf.

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The potential impacts associated with earthquakes do not require a separate hazards analysis. As explained in 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)." The hazard analysis presents the maximum potential impact data for each component of the proposed project. No evidence has been presented that significant damage at refineries has or will occur as a result of a catastrophic event.[223] However, if all project components were to experience the maximum potential upsets concurrently, the result would be the combination of all the vulnerability zones presented in Figures 4.3-1, 4.3-2, and 4.3-3 of the DEIR.

New equipment must be built to current seismic building code requirements and existing equipment is subject to CalARP regulations which require periodic hazards review that may include seismic evaluation depending on the relevant process hazards. These periodic reviews are performed to minimize risk of accidental releases by addressing any issues identified by the review.

Comment G1-78.238

Further, a California Division of Mines and Geology planning scenario for a major earthquake on the Newport-Inglewood fault zone, the closest fault zone to the Refinery, about 1.5 to 2.0 miles northeast,[345] evaluated the impact of an earthquake in this fault zone on refineries in the area, including the Carson (then owned by ARCO) and Wilmington (then owned by Union Oil) Operations. It noted that earthquakes may damage incoming crude oil transportation facilities and refineries may suffer "direct damage such as broken piping, buckled storage tanks, damage to processing towers, (b) suffer consequential damage from fire following the earthquake..." It goes on to identify damage to refineries during earthquakes, as follows:[346]

> an earthquake. In the 1952 Kern County earthquake, the Paloma Cycling Plant survived the earthquake quite well until two large butane spheres collapsed releasing highly volatile material. The gaseous material spread out over the area and was ignited within minutes. The 1964 Niigata, Japan, earthquake resulted in fire at the Showa Oil Company refinery which burned continuously for two weeks. Fire occurred at failed storage tanks following the 1964 Alaska earthquake.

The types of damage that might be expected from a major earthquake on the Newport-Inglewood fault zone include:

> The use and storage of different types of hazardous materials at refineries are more of a hazard to the public than fire, because of the potential release of toxic fumes.
>
> The low earthen embankments used as retention dikes around fuel and oil storage tanks are subject to failure from earthquake shaking. The locations of these types of structures, their vulnerability, and the consequences of failure need to be examined as part of any company's emergency planning program.

345 DEIR, p. 4-106.

346 California Department of Conservation, Division of Mines and Geology, Planning Scenario for a Major Earthquake on the Newport-Inglewood Fault Zone, Special Publication 99, 1988, pp. 170-

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[223] The Southern California Earthquake Data Center presents information on historical earthquakes including the 1933 Long Beach and 1994 Northridge earthquakes. The information explains that the significant structural damage caused by the quakes was to unreinforced masonry. This does not apply to the Refinery, because the equipment at the Refinery is built on reinforced foundations and built to current seismic code.

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As explained in G1-78.237, the cause of the hazard has no bearing on the hazard consequence analysis. The DEIR evaluated releases from storage tanks, releases from pipelines, and releases from process units (see FEIR Section 4.3.2.1 on pages 4-45 through 4-54).

The report cited in the comment was prepared in 1988 and seismic building code standards have been updated becoming more protective since that time. The proposed project must comply with current building codes that include seismic standards, among other requirements (see Response G1-78.235). Therefore, seismic hazards have been fully addressed in the DEIR.

Comment G1-78.239

A further consideration is the age of the facilities. The DEIR assumed no significant adverse impacts from seismic hazards as the Project will comply with the California Building Code.[347] Building codes are evolving, routinely updated to address experience gained in recent seismic events. While a new facility in 2016-2017 may well comply with then current building codes, the facility may not comply with codes 20 years in the future, when a major earthquake may occur. G1-78.239

Further, while the new equipment and modifications to existing equipment must comply with California Building Code, existing processing equipment whose throughput is increased is many decades old. They were not built to current earthquake standards, which have changed considerably since the modified processing units were constructed. G1-78.239 cont'd.

Thus, the DEIR's conclusion that "[n]o significant adverse impacts from seismic hazards are expected since the proposed project will be required to comply with the California Building Codes, including those addressing seismic effects,"[348] is misleading. In fact, the Project site is located in an area of historic (or has the potential for) liquefaction.[349] Thus, impacts due to liquefaction and expansion-induced accidents should have been considered.

Other external events not considered include sea level rise, floods, and sabotage.

[347] DEIR, pp. 2-33, 4-106 ("Thus, the proposed project would not alter the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structure to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides is not anticipated.")

[348] DEIR, p. 4-106.

[349] DEIR, Appendix A, p. A-70.

Response G1-78.239

As explained in Responses G1-78.237 and G1-78.238, new equipment is designed to comply with current building codes and existing equipment is periodically evaluated using a hazard review process in accordance with CalARP regulations. For the proposed project, all project modifications require the affected units to undergo a hazards review (Process Hazard Analysis (PHA)), including seismic standards review, where appropriate. Through the PHA, potential risk issues are identified and remediated as needed.

Under CEQA, the term "environment" means "the *physical conditions* which exist within the area *which will be affected by a proposed project*, including land, air, water, minerals, flora, fauna, noise, objects of historic or aesthetic significance." (CEQA Guidelines § 21060.5, emphasis added). The same seismic conditions will occur with or without the proposed project. The potential for seismic events is not altered by the proposed project. The potential impacts associated with earthquakes do not require a separate hazards analysis. As explained in 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)." The hazard analysis presents the maximum impact data for each component of the proposed project.

The comment has taken the statement made in the NOP/IS regarding liquefaction out of context. The response to CEQA Checklist VII. c) concluded that “the proposed project would not be expected to alter or make worse any existing potential for subsidence, liquefaction, et cetera.” Additionally, the Geology and Soils description in the NOP/IS concluded that “no significant adverse impacts to geology and soils are expected as a result of construction and operational activities associated with the proposed project. Since no potentially significant adverse geology and soils impacts were identified, no further evaluation will be required in the EIR.” (see Appendix A pages A-63 through A-71). These conclusions are supported by the fact that the proposed project will not alter the seismic environment. Nor will it worsen the potential for hazards such as a rising sea level, flooding or sabotage. Analysis of such potential impacts would amount to consideration of the environment’s impact on the proposed project. The California Supreme Court has recently confirmed that CEQA only requires evaluation of a proposed project effects on the environment, not the impact of the environment on the proposed project (see *California Building Industry Association v Bay Area Air Quality Management District*, 62 Cal. 4th 369, (2015)). A similar conclusion was reached by the court in *Preserve Poway vs. City of Poway*, 245 Cal. App. 4th 560 (2016).

Comment G1-78.240

B. **Health Impacts of Accidents Were Not Evaluated**

The DEIR evaluated the health impacts of routine operational emissions, but failed to evaluate the health impacts of emissions that occur during accidents. The DEIR selected toxic endpoints for five accident scenarios, based on ERPG’s for H_2S or SO_2.[350] However, these toxic endpoints are not a reasonable basis to evaluate the significance of accidents that release TAPs and do not constitute or substitute for a health risk assessment. These include: G1-78.240

- H_2S from the HCU
- H_2S from the Mid-Barrel Distillate Treater
- H_2S from the CRU-3
- H_2S from the PSTU
- SO_2 from the SARP

[350] DEIR, Table 4.3.2.

Response G1-78.240

The OEHHA Air Toxic Hot Spots Guidance Manual released in February 2015 provides guidance on preparing health risk assessments. The Manual states, "The emissions reported under this program are routine or predictable, and include continuous and intermittent releases and predictable process upsets or leaks. Emissions for unpredictable releases (e.g., accidental catastrophic releases) are not reported under this program." Therefore, it is not appropriate to use the OEHHA HRA methodology with respect to hazard release scenarios as suggested in the comment.

Emergency releases are best evaluated using toxic endpoints based on the Emergency Response Planning Guidelines (ERPGs) because the events are short in duration and releases are not continuous. The ERPGs are designed to establish lowest levels at which health effects will begin to be experienced at their respective toxic endpoints (i.e., lungs) for up to a one-hour exposure. Therefore, they are suitable for determining hazard impacts from short duration accidental releases.

Comment G1-78.241

1. The EPRG-2 Is Not a Reasonable Significance Criterion to Evaluate Accidental Releases

G1-78.241

The significance of accidents involving the release of H_2S and SO_2 was evaluated using Emergency Response Planning Guideline 2 (ERPG-2) levels.[351] These values do not protect public health. Further, these values are not reasonable significance criteria for evaluating the public health impacts of releases of hazardous chemicals during refinery accidents.

An ERPG-2 is the maximum airborne concentration below which nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action. Sensitive members of the public, such as old, sick, or very young people are not covered by these guidelines and they may experience adverse effects at concentrations below the ERPG levels.[352] Thus, evaluations based on ERPGs are no substitute for a health risk assessment, which covers sensitive members of the population.

G1-78.241 cont'd.

These ERPGs are also not appropriate as endpoint hazard criteria for accidents. First, ERPGs are focused on an exposure of 1 hour. Exposures resulting from accidents are typically much longer. The American Industrial Hygiene Association (AIHA), who developed the ERPGs, "strongly advises against trying to extrapolate ERPG values to longer periods of times."[353] The proposed use as "endpoint hazard criteria" in the hazard analysis is inappropriate as exposures from accidents typically last longer than 1 hour. The DEIR fails to disclose the exposure duration associated with each accident scenario, and thus fails as an informational document.

[351] DEIR, Table 3.3-1, footnote (c), p. 4-45, Table 4.3-1; Appx. C, Table 3-1, p. 17.

[352] Office of Response and Restoration, Emergency Response Planning Guidelines (ERPGs); Available at: http://response.restoration.noaa.gov/oil-and-chemical-spills/chemical-spills/resources/emergency-response-planning-guidelines-erpgs.html.

[353] Ibid.

Response G1-78.241

As explained in Response G1-78.240, HRAs are not intended to be conducted for catastrophic accidents.

The use of ERPG2 levels was selected because it represents the "maximum airborne concentration below which nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair an individual's ability to take protective action." [224] While an incident may have a duration of longer than one hour, the ERPG2 is established to account for the fact that impacted areas will be evacuated within an hour of exposure at the ERPG2 concentration, if an evacuation is required.

Contrary to the claim in the comment, the ERPG addresses sensitive members of the general public. The ERPG states "additional factors may be applied when the data are insufficient or when there are unusually sensitive members of the general population (e.g., a specific metabolic defect that makes some individuals unusually susceptible to the toxicity of the substance under consideration)." The ERPG does not require the use of additional factors but explains that they may be applied.[225] However, no guidance on what factor to use is provided. Here, the surrounding area is industrial, so the application of additional factors is not called for. Nonetheless, the use of ERPGs does not exclude sensitive populations as the comment claims.

A review of recently certified CEQA documents has shown that it is common practice by lead public agencies to use ERPGs for assessing hazard impacts without adjusting for sensitive populations.[226]

[224] 2016 ERPG/WEEL Handbook, available at https://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines/Documents/ERPG%20Intro%20%282016%20Handbook%29.pdf, page 4.

[225] 2016 ERPG/WEEL Handbook, available at https://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines/Documents/ERPG%20Intro%20%282016%20Handbook%29.pdf, page 14.

[226] City of Richmond, 2008. Chevron Energy and Hydrogen Renewal Project. http://www.ci.richmond.ca.us/DocumentCenter/Home/View/3264; San Luis Obispo County, 2014. Phillips 66 Company Rail Spur Extension and Crude Unloading Project http://www.ci.benicia.ca.us/vertical/sites/%7BF991A639-AAED-4E1A-9735-86EA195E2C8D%7D/uploads/DraftEIR-SanLuisObispoCty2014.pdf; City of Benicia, 2015. Valero Benicia Crude by Rail Project. http://www.ci.benicia.ca.us/vertical/Sites/%7B3436CBED-6A58-4FEF-BFDF-F9331215932%7D/uploads/Valero_Benicia_Crude_by_Rail_RDEIR_Complete_Version.pdf, Contra Costa County, 2014. Phillips 66 Propane Recovery Project. http://www.cccounty.us/DocumentCenter/View/33804.

Comment G1-78.242

ERPGs should be used to help protect the public only when AEGLs (Acute Exposure Guidelines Levels) aren't available and there has been a chemical release that is short-term in duration. The durations of the exposure from the modeled accidents were not disclosed in the DEIR, but are unlikely to be "short term". ERPGs estimate how nearly all of the public (except for sensitive individuals) would react to a release of this nature, so they can be used to identify areas where a hazard exists if the concentration of hazardous gas is exceeded for the specified exposure duration. For example, in areas with concentrations just above the ERPG-1, most people would experience temporary, non-disabling effects. On the other hand, in areas with concentrations just above the ERPG-2, most people would experience significant—but not life-threatening—health effects.[354] The DEIR's choice of the ERPG-2 to evaluate the significance of accidental releases of H_2S eliminates the most sensitive segment of the population. This is a violation of CEQA, which does not recognize any cutouts for G1-78.242

sensitive populations. Au contraire, these populations are the most important to protect.

As AEGLs exist for H_2S, they should have been used to evaluate the significance of accidents involving the release of hazardous substances. AEGLs estimate concentrations at which most people, including sensitive individuals, will begin to experience health effects. AEGLs should be used to help protect the public when there has been a chemical release that is short-term in duration. AEGLs estimate how the general public would react to a release of this nature, so they can be used to identify areas where a hazard exists if the concentration of hazardous gas is exceeded for the specified exposure duration. For example, in areas with concentrations just above the AEGL-1, most people would experience temporary, non-disabling effects. On the other hand, in areas with concentrations just above the AEGL-2, most people would experience significant—but not life-threatening—health effects.[355] The AEGLs for H_2S, are:

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Table 8: AEGLs for Hydrogen Sulfide[356]

Hydrogen sulfide 7783-06-4 (Final)

	10 min	30 min	60 min	4 hr	8 hr
ppm					
AEGL 1	0.75	0.60	0.51	0.36	0.33
AEGL 2	41	32	27	20	17
AEGL 3	76	59	50	37	31

Table 8 shows that for H_2S, the AEGL-1 and AEGL-2 levels are lower than the ERPG-2 value of 30 ppm used to evaluate the significance of accidents in the DEIR. The DEIR should be revised to substitute the AEGL-1 levels for the ERPG-2 levels used to evaluate significance, with the level selected based on the duration of the exposure.

354 Office of Response and Restoration, Emergency Response Planning Guidelines (ERPGs); Available at: http://response.restoration.noaa.gov/oil-and-chemical-spills/chemical-spills/resources/emergency-response-planning-guidelines-erpgs.html.

355 Office of Response and Restoration, Acute Exposure Guideline Levels (AEGLs); Available at: http://response.restoration.noaa.gov/oil-and-chemical-spills/chemical-spills/resources/acute-exposure-guideline-levels-aegls.html.

356 EPA, Hydrogen Sulfide Results – AEGL Program; Available at: https://www.epa.gov/aegl/hydrogen-sulfide-results-aegl-program.

Response G1-78.242

The SCAQMD, as the lead agency, has the discretion to establish significance criteria (CEQA Guidelines §15064.7). The use of ERPGs or AEGLs for a one-hour exposure would yield similar results (e.g., for H_2S AEGL2= 27, ERPG2 = 30). The use of the ERPGs is appropriate for short duration exposures since ERPGs were specifically created to anticipate adverse health effects from once-in-a-lifetime, short-term (1-hour) exposure to a chemical release emergency[227].

While an incident may have a duration of longer than one hour, the ERPG2[228] is established to account for the fact that individuals will evacuate the area within an hour of exposure at the ERPG2 concentration. So, it is unlikely that unprotected exposures would last longer than one hour. The hazard analysis in the DEIR determined that significant impacts (i.e., off-site impacts regardless of receptor type) from hazard impacts would occur (see DEIR page 4-52) and mitigation measures were identified and imposed (see DEIR Section 4.3.3 on pages 4-68 and 4-69). The use of ERPG2s is conservative because they assume the wind remains blowing in the same direction for the duration of an hour. As explained in Response G1-78.241, it is not accurate to state that ERPG levels exclude sensitive persons.

Comment G1-78.243

2. The Use of ERPGs or AEGLs Is Not A Health Risk Assessment

Finally, the use of either of these metrics, EPRG or AEGL, is no substitute for a health risk assessment, which evaluates chronic, acute and carcinogenic risks. The DEIR does not include a health risk assessment for accidental releases. The significance

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[227] 2016 ERPG/WEEL Handbook, available at https://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines/Documents/ERPG%20Intro%20%282016%20Handbook%29.pdf, page 1 and 2.

[228] 2016 ERPG/WEEL Handbook, available at https://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines/Documents/ERPG%20Intro%20%282016%20Handbook%29.pdf, page 4.

of accidents with a toxic endpoint was assessed for only a single pollutant. However, accidents typically release a complex soup of TAPs, none of which were identified in the DEIR. These include mercaptans, dimethyl sulfide, benzene, toluene, hydrogen cyanide, carbon monoxide, fine particulate matter, and smoke, among many others.[357] The acute, 8-hour and chronic reference exposure (RELs) levels used in health risk assessments are much lower than the EPRGs (or AEGLs) used to evaluate the significance of accidents that release TAPs. Table 9 compares ERPGs, AEGLs, and the acute (for a 1-hour exposure) REL for H_2S. Table 9 shows that the DEIR selected the least protective metric to assess the significance of accidents that release toxic air pollutants. Thus, it is likely that many additional accident scenarios would result in significant impacts than disclosed in the DEIR.

G1-78.243 cont'd.

Table 9.
Comparison of Various Measures of 1-hr Exposure to H_2S

Metric	Exposure Duration (Hr)	Concentration (ppm)
Acute REL[358]	1 hr	0.03
AEGL-1[359]	1 hr	0.51
AEGL-2[360]	1 hr	27
ERPG-2[361]	1 hr	30

Note: Used in DEIR

[357] Ruei-HaoShie and Chang-Chuan Chan, Tracking Hazardous Air Pollutants from a Refinery Fire by Applying On-Line and Off-Line Air Monitoring and Back Trajectory Modeling, Journal of Hazardous Materials, v. 261, October 2013, pp. 72-82; Available at: http://www.sciencedirect.com/science/article/pii/S0304389413004962.

[358] OEHHA Acute, 8-hour and Chronic Reference Exposure Level (REL) Summary, March 28, 2016; Available at: http://oehha.ca.gov/air/general-info/oehha-acute-8-hour-and-chronic-reference-exposure-level-rel-summary.

[359] https://www.epa.gov/aegl/access-acute-exposure-guideline-levels-aegls-values#chemicals.

[360] https://www.epa.gov/aegl/access-acute-exposure-guideline-levels-aegls-values#chemicals.

[361] https://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines/Documents/2015%20ERPG%20Levels.pdf.

Response G1-78.243

Health risk assessment one-hour exposure evaluations are based on a one-hour exposure concentration that could persist for an entire hour (e.g., operational fugitive emissions), on any hour of the year. This could be a single hour in a year, a routine period (e.g., eight hours a day) or every hour in a year.. This is not the case for an emergency situation, where there may be an exposure duration of less than one hour.

As explained in Response G1-78.240, acute REL values are not appropriate for accidental catastrophic releases. ERPG levels, however, are based on single, short-duration exposures and establish thresholds that would not cause permanent health effects. A significance threshold based on analyzing permanent health effects is appropriate for unpredictable accidental releases.

An HRA, on the other hand, seeks to analyze the risks from predictable process upset emissions (i.e., scheduled releases) that could create an acute exposure, and thus seeks to prevent non-permanent health impacts. For purposes of hazard impacts analysis, the exposure duration is short due to the rapid release rate when equipment fails and is more appropriately compared to an ERPG. Thus, the DEIR used the appropriate significance criteria for hazard impacts.

Comment G1-78.244

C. All Feasible Hazard Mitigation Not Required

The DEIR concluded that the impacts of the Project on hazards associated with the Naphtha Isomerization Unit, new crude tanks, SARP, and interconnecting piping are significant and would remain significant after mitigation.[362] Thus, all feasible mitigation is required.

The proposed mitigation requires: (1) an Emergency Action Plan[363]; (2) compliance with Process Safety Management requirement[364]; and (3) development of a Risk Management Plan[365],[366] These programs are required by existing federal and state regulations. Thus, they are not mitigation as they are required in the baseline. G1-78.244

Further, these programs were in place at Chevron at the time of the August 2012 accident discussed above, and the 2010 accident at Tesoro's Anacortes refinery. They obviously did not prevent these catastrophic accidents. Further, the U.S. Chemical Safety and Hazard Investigation Board concluded that these programs were not effective at preventing refinery accidents in its analysis of the Tesoro Anacortes accident.[367] The recent Chevron FEIR incorporated many additional mitigation measures to improve these programs,[368] which should be required for the Project. This mitigation program is attached to my comments as Exhibit 30.[369]

[362] DEIR, p. 1-29, Sec. 1.9.2.3.

[363] 29 CFR 1910.38.

[364] 40 CFR Part 1910, Section 119.

[365] 19 CCR Division 2, Chapter 4.5.

[366] DEIR, p. A-143.

[367] U.S. Chemical Safety and Hazard Investigation Board, Tesoro Anacortes Refinery, May 2014, Section 7.8.

[368] Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1& 2, p. 4-40, pp. 5-39 to 5-53, Available at: http://chevronmodernization.com/project-documents/.

[369] Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1 & 2, p. 4-40, pp. 5-39 to 5-53, (Exhibit 30).

Response G1-78.244

First, contrary to the suggestion in the comment, compliance with regulatory programs and requirements are considered appropriate mitigation under CEQA. "[A] condition requiring compliance with regulations is a common and reasonable mitigation measure, and may be proper where it is reasonable to expect compliance."[229] In fact, courts have interpreted the Guidelines

[229] *Oakland Heritage Alliance v. City of Oakland* (2011) 195 Cal.App.4th 884, 906; *id.* at 904 ("We agree with the City that compliance with the Building Code, and the other regulatory provisions, in conjunction with the detailed Geotechnical Investigation, provided substantial evidence that the mitigation measures would reduce seismic impacts to a less than significant level.")

as “specifically recogniz[ing] that mitigation measures requiring adherence to regulatory requirements or other performance criteria are permitted.”[230]

The comment suggests that another project’s mitigation program attached as Exhibit 30 should be required for the proposed project. However, Exhibit 30 submitted on the flash drive is the Notice of Completion, table of contents, and selected pages of the DEIR for the proposed project and is not the Chevron FEIR as the comment claims.

Nonetheless, the SCAQMD has reviewed the Chevron FEIR hazard mitigation measures. Those mitigation measures related to safety plans and inspections are functionally equivalent to HHM-1 of the DEIR that requires early implementation of safety requirements, such as Process Safety Management (PSM) hazards assessments and updates to the Risk Management Plan (RMP), Hazardous Materials Business Plan, and Spill Prevention Control and Countermeasure Plan.

The Refinery is inspected for personal and process safety by CalOSHA (typically once per year) for CalARP compliance by the Unified Program Agency – the Los Angeles City and County Fire Departments (every two to three years), and a PSM/RMP by multiple agencies including U.S. EPA, SCAQMD, Los Angeles City Fire Department, Los Angeles County Fire Department, and CalOSHA (every three years). In addition, the SCAQMD has its own enforcement inspectors that routinely inspect the Refinery for compliance with SCAQMD Rules and Regulations.

Other mitigation measures required in the Chevron FEIR are specific to the Chevron Richmond Refinery and thus are not applicable to, or necessary for, the proposed project. Therefore, the comment has not identified additional effective mitigation measures that should be incorporated into the proposed project.

Comment G1-78.245

VIII. CONSTRUCTION MITIGATION

The DEIR concluded that emissions of VOC and NOx from construction of the Project are significant.[370] The DEIR thus proposed eight mitigation measures with four exceptions plus eight best management practices.[371] The DEIR concludes that "[c]onstruction emissions for the proposed project for VOC and NOx are expected to G1-78.245

remain significant following mitigation. This portion of the project will reduce the amount of time that vessels spend within the port and increase the amount of crude oil that can be unloaded and stored"[372] Thus, all feasible mitigation is required. G1-78.245 cont’d.

[230] *Citizens for a Sustainable Treasure Island v. City & County of San Francisco* (2014) 227 Cal.App.4th 1036, 1059-60 (citing CEQA Guidelines § 15126.4(a)(1)(B)); *see also Center for Biological Diversity v. Dept. of Fish & Wildlife* (2015) 234 Cal.App.4th 214, 245-46 (compliance with federal regulations requiring a hatchery genetic management plan was an appropriate and sufficient measure meant to mitigate impacts on fish); *Citizens Opposing a Dangerous Environment v. County of Kern* (2014) 228 Cal.App.4th 360, 383 (obligation to observe Federal Aviation Agency rules and regulations was an appropriate mitigation measure for impacts to aviation safety).

370 DEIR, Table 4.2-2 and p. 4-36.
371 DEIR, pp. 4-36 to 4-40.
372 DEIR, p. 4-42.

Response G1-78.245

The comment accurately reflects the conclusions of the DEIR. Construction emissions are significant for VOC and NOx and all feasible mitigation measures have been imposed.

Comment G1-78.246

A. Proposed Mitigation Is Inadequate

1. Electric Equipment

Mitigation Measures A-5 and A-6 require the project proponent to survey, identify, and document all construction areas served by electricity and to use only electric welders and power generators in these areas.[373] The documented survey is an excellent requirement. However, other construction equipment is available in electrical models. These include pumps, jack hammers, excavators,[374] augers, and trucks.[375] Thus, these two mitigation measures should be combined and revised to require the use of electrical equipment in all applications where it is available.

In addition to the narrow focus on only welders and generators, the EIR also contains "exceptions" if the equipment is leased or rented and the project proponent/contractor has "attempted in good faith and due diligence to lease the vehicle or equipment ...but that vehicle or equipment is not available." This allows poor planning and implementation to side step mitigation. Electric equipment is widely available and should be required with no exceptions.

G1-78.246

The BAAQMD, for example, recently recommended the following mitigation measures to reduce NOx emissions during construction of the proposed WesPac Pittsburg Energy Infrastructure Project ("WesPac Project"):[376]

- Prohibit diesel generators where access to the electrical grid is available.
- Require electrification of motors, pumps, and other power tools whenever feasible.[377]
- The BAAQMD equivalent mitigation includes no escape clauses and requires electrification of all equipment, where feasible.

G1-78.246 cont'd.

373 DEIR, p. 4-37.

374 Hitachi Construction Machinery, Electric Construction Machinery; Available at: https://www.hitachi-c-m.com/global/environment/showcase/motor_driven.html.

375 The Electrical Resource; Available at: http://www.theelectricalresource.com/category/earth-augers.html.

376 The WesPac Project application was withdrawn on November 16, 2015. However, this does not affect the BAAQMD's recommendation for appropriate construction mitigation measures.

377 Jean Roggenkamp, BAAQMD, Letter to Kristin VahlPollot, City of Pittsburg, Re: WesPac Pittsburg Energy Infrastructure Project Recirculated DEIR, September 13, 2013; http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA%20Letters/WesPac%20Pittsburg%20Energy%20Infrastructure%20Project%20DEIR.ashx.

Response G1-78.246

The DEIR presents a conservative construction analysis. In order to avoid the underestimation of emissions from construction, only equipment that Tesoro has full control over was included in the mitigated emissions analysis. This includes the use of electric welders where grid power is available.

The use of this assumption in the DEIR, however, does not mean that electrified equipment will not be used elsewhere. On the contrary, Mitigation Measure A-1 requires the inclusion of Best Management Practices in the Construction Management Program. Best Management Practice 7 requires the use of electric power in lieu of diesel power. Therefore, all equipment will be electrified where feasible and available, including the use of power tools. To reinforce the Best Management Practice 7, Mitigation Measure A-5 will be revised to include use of electric power tools when feasible and available.

Some equipment, such as the pumps used for hydrotesting and excavators, simply cannot be electrified. The available portable electric pumps are not big enough and cannot move enough liquid for the construction applications at the Refinery. The electric equipment referenced in comment Footnote 374 is equipment whose purpose is to remain in a single location where electricity is available. The proposed project is located throughout the Refinery (see DEIR Figures 2-14, 2-15, 2-16, and 2-17) and requires construction equipment to move to various locations throughout the Refinery. Therefore, the use of the equipment referenced in comment Footnote 374 is not feasible. Mini excavators, which are available from Hitachi, are limited to about 600 pounds. These undersized electric excavators are intended for use in small construction areas and are not appropriate for the proposed project due to its size. Therefore, electric pumps and excavators will not be used to construct the proposed project. The equipment referenced in the comment Footnote 375 are electrical augers that are designed for shallow digging (to approximately 10 feet) to replace the manual augers used by one or two people. Because the proposed project requires piling installation to depths of 25 to 95 feet, which are greater than the capabilities of this equipment, electrical augers are not appropriate for the proposed project.

Tesoro does not own or operate the equipment that will be used during the construction of the proposed project. However, Tesoro contractually obligates the contractors and subcontractors to provide the cleanest equipment whenever feasible and available, as defined in the DEIR in Mitigation Measures A-3 and A-7. Further, contractors and subcontractors will be required to properly maintain their equipment at all times as required in the Best Management Practices that are included the Construction Management Program in Mitigation Measure A-1. Therefore, the mitigation suggested in Comment G1-78.246 is already part of the DEIR.

Ultimately, Tesoro seeks to use the correct, appropriately sized equipment to do the job safely and efficiently in order to minimize risk to personnel and the environment. The DEIR includes specific, narrowly defined exceptions to Mitigation Measures A-3 and A-7 that limit the circumstances where Tier 4 construction equipment and trucks meeting U.S. EPA's 2007 standards may be considered unavailable. The mitigation measures are simply limited by feasibility and the availability of equipment. As explained above, these mitigation measures are equivalent to the "WesPac Project" mitigation measures suggested in the comment. The exceptions listed in the DEIR Mitigation Measures are actually designed to pre-define or limit the situations in which the use of the cleanest equipment is not feasible or available. The definition of the acceptable exceptions in the Mitigation Measure A-5 is actually more restrictive than the suggested language in the comment "where available or where or whenever feasible".

Comment G1-78.247

2. <u>Compliance With Existing Regulations Not Valid CEQA Mitigation</u>

Mitigation Measure A-4 (off-road vehicles) prohibits idling longer than 5 minutes for off-road vehicles.[378] Limiting idle time to 5 minutes is required by 13 CCR 2449[d][3], 2485 for off-road vehicles.[379] Thus, this is not valid CEQA "mitigation". This mitigation measure should be modified to lower the maximum idling time to 3 minutes. In addition to lowering the idling time, the construction contractor shall maintain a written idling policy and distribute it to all employees and subcontractors. The on-site construction manager shall enforce this limit. G1-78.247

[378] DEIR, pp. 4-36 and 4-37.

[379] https://govt.westlaw.com/calregs/Document/ID1C693E02DDD11E197D9B83B68A61150?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

Response G1-78.247

First, as explained in Response G1-78.244, mitigation measures that require compliance with regulatory programs and requirements are appropriate under CEQA. Further, while Mitigation Measure A-4 does mirror the CARB regulation on idling, including the requirement to have a written idling plan, it also imposes additional conditions and mechanisms beyond what is required under the regulation to enforce the five-minute idling regulation. For example, the mitigation measure requires contractors to sign contracts and post signage onsite to promote and remind operators of the idling regulation. The Construction Management Program includes Tesoro monitoring contractors and onsite construction and operations for health, safety, and environmental compliance, including the five-minute idling rule.

Diesel engines have an optimal operating temperature. Idling an engine allows the engine to maintain operating temperatures. Therefore, changing the idling limits may actually generate more emissions due to the startup emissions and additional idling required to bring the equipment to operating temperatures. The reduction of idling from five minutes to three minutes is not necessarily environmentally beneficial and the comment does not provide substantial evidence otherwise. Therefore, no changes to Mitigation Measure A-4 are required.

Comment G1-78.248

3. Buffer Zone

Best Management Practices (BMPs) require maintaining a 1000-foot buffer zone between truck traffic and sensitive receptors, where feasible.[380] This is not adequate mitigation for several reasons.

First, the measure is limited to "truck traffic." The measure should be expanded to include all diesel- and gasoline-powered on-site and off-site construction equipment.

Second, the DEIR does not provide any basis for selecting 1,000 feet as the buffer zone. Buffer zones should be determined from health risk assessments. The DEIR is inadequate as it failed to include a health risk assessment for construction emissions. As construction will occur near sensitive receptors and diesel exhaust is a potent carcinogen, construction health impacts may be significant with a 1,000 foot buffer zone.

Third, the DEIR does not require that the buffer distance is enforced and verified as adequate. A field monitoring study should be conducted at each sensitive receptor(s) adjacent to each construction site to verify that 1,000 feet is adequate and adjusted accordingly.

[380] DEIR, p. 4-40, BMP #3.

G1-78.248

Response G1-78.248

No offsite construction is planned within 1,000 feet of sensitive receptor locations. Therefore, the mitigation measure does not require modification. The 1,000-foot buffer zone is not an arbitrary distance. The 1,000-foot buffer zone follows the recommendations outlined in the Los Angeles County Metro Green Construction Policy. It is twice the 500-foot buffer zone recommended by CARB for separating sensitive receptors from heavily-traveled roadways that include diesel trucks.[231] Therefore, the mitigation measure focuses on diesel truck traffic.

The 1,000-foot buffer zone encompasses two small areas of sensitive receptors due to the location of onsite construction. The two onsite construction areas have residential receptors just within the 1,000-foot zone (i.e., west of the Carson Crude Terminal and west of the Wilmington Operations). As explained in Response G1-78.258, the health risk impacts from construction are less than significant for sensitive receptors and offsite workers, including the residential receptors within the proposed 1,000-foot buffer zone. Consequently, there is no need to modify the buffer zone to include onsite construction equipment since no significant health risks were identified in these areas. Therefore, additional mitigation is not warranted. Provisions for establishing and enforcing the buffer zone will be included in the Construction Management Program (see Section 4.2.3 of the FEIR).

[231] CARB 2005. Air Quality and Land Use Handbook: A Community Health Perspective, April 2005, Table 1-1, https://www.arb.ca.gov/ch/handbook.pdf.

Comment G1-78.249

4. Exceptions

The DEIR includes "exceptions" to complying with mitigation measures A-2 to A-8 for on-road and off-road construction equipment and generator requirements. These exceptions allow stepdown to the next cleanest piece of equipment or vehicle available.[381] These "exceptions" relax mitigation if the equipment required to meet mitigation measures A-2 to A-8 is not available for lease or rental; funding has not arrived to cover the retrofit cost; or the equipment has not arrived when purchased at least 60 days before it is required and the equipment is not available for lease or short-term rental within 200 miles of the project site. These exceptions allow poor planning and implementation to trump mitigation and thus render the measures unenforceable. The DEIR should be modified to require backup mitigation of equal effectiveness if the primary mitigation is not available. Backup mitigation could include the following: G1-78.249

- If a compliant engine is not available, equip available engines with retrofit controls;
- Extend the search radius to 1,000 miles from the Project site;
- Modify on-site stationary source equipment to reduce NOx and VOC during the construction period.

[381] DEIR, pp. 4-38 to 4/39.

Response G1-78.249

The mitigation measures in the DEIR are more restrictive and thus more beneficial than the proposed language in Comment G1-78.246, which more vaguely allows avoiding mitigation where not "feasible". The DEIR specifically limits the project proponent's discretion to make a determination that the cleanest equipment is not feasible or available to those instances defined in the mitigation measure itself, see Response G1-78.246.

Retrofit of contractor's equipment with add-on controls is not feasible. Specifically, refineries have experienced safety issues (fires) and equipment performance issues with retrofit controls.[232] For safety reasons, these requirements cannot be imposed on a contractor.

The 200-mile radius included in the mitigation measure covers the Los Angeles and San Diego metropolitan areas, which are highly urbanized areas with heavy construction. If the requisite equipment is available, it will most likely be found in the metropolitan areas that are within 200 miles of the proposed project. Extending the search radius to 1,000 miles will not improve the availability and feasibility of using this equipment. In fact, there are several scenarios where using non-local equipment would adversely affect the local, regional, and global environments. The first, and most obvious, is equipment brought from up to 1,000 miles away would add construction equipment and the associated emissions to the Basin as well as incur the transportation emissions for the delivery. Another scenario is adding emissions from transporting equipment in and out of the Basin for a short job.

[232] Process Safety Progress, 2000. Safety Hazards Associated with Air-emission Controls, pp. 25-31.

As suggested, Mitigation Measure A-9 requires NOx reductions from stationary sources during the construction period.

Comment G1-78.250

5. Additional Feasible Mitigation

An EIR may conclude that an impact is significant and unavoidable only if all available and feasible mitigation measures have been proposed, but are inadequate to reduce the impact to a less than significant level.[382] If supported by substantial evidence, the lead agency may make findings of overriding considerations and approve the project in spite of the significant and unavoidable impact(s). However, the lead agency cannot simply conclude that an impact is significant and unavoidable without requiring all feasible mitigation, as here. G1-78.250

Additional feasible construction exhaust mitigation measures are included in CEQA guidelines of various air quality management districts, have been required in recent CEQA documents,[383,384,385,386,387] or are recommended by the U.S. EPA.[388] Some additional feasible mitigation measures from these sources that should be required for this Project are as follows:

- Implement EPA's National Clean Diesel Program;[389,390,391]
- Diesel- or gasoline-powered equipment shall be replaced by lowest emitting feasible for each piece of equipment from among these options: electric equipment whenever feasible, gasoline-powered equipment if electric infeasible;
- If cranes are required for construction, they shall be rated at 200 hp or greater equipped with Tier 4 or equivalent engines;
- Use electric fleet or alternative fueled vehicles where feasible including methanol, propane, and compressed natural gas;

G1-78.250 cont'd.

[382] See Cal. Code Regs. Titl.14 ("CEQA Guidelines"), § 15126.2.

[383] SWCA Environmental Consultants, Draft Initial Study and Mitigated Negative Declaration for the California American Water Slant Test Well Project, Prepared for City of Marina, May 20 (IS/MND).

[384] MBUAPCD 2008, Table 8-2 to 8-4, and 8-7.

[385] Chevron Refinery Modernization Project EIR, March 2014, Chapter 4.8, Greenhouse Gases; Available at: http://chevronmodernization.com/wp-content/uploads/2014/03/4.8_Greenhouse-Gases.pdf and Chapter 5, Mitigation Measure Monitoring and Reporting Program; Available at:

https://s3.amazonaws.com/chevron/Final+EIR/5_MMRP.pdf.

386 San Luis Obispo County Air Pollution Control District, CEQA Air Quality Handbook, April 2012, http://www.slocleanair.org/images/cms/upload/files/CEQA_Handbook_2012_v1.pdf.

387 Bay Delta Conservation Plan RDEIR/SDEIS, 2015; http://baydeltaconservationplan.com/RDEIRS/Ap_A_Rev_DEIR-S/App_22E_Gen_Conform_Determin.pdf.

388 Verified Technologies List; http://baydeltaconservationplan.com/RDEIRS/Ap_A_Rev_DEIR-S/App_22E_Gen_Conform_Determin.pdf.

389 Northeast Diesel Collaborative, Best Practices for Clean Diesel Construction.Successful Implementation of Equipment Specifications to Minimize Diesel Pollution; http://www2.epa.gov/sites/production/files/2015-09/documents/best-practices-for-clean-diesel-construction-aug-2012.pdf.

390 U.S. EPA, Cleaner Diesels: Low Cost Ways to Reduce Emissions from Construction Equipment, March 2007; http://www2.epa.gov/sites/production/files/2015-09/documents/cleaner-diesels-low-cost-ways-to-reduce-emissions-from-construction-equipment.pdf.

391 NEDC Model Contract Specification, April 2008; http://www2.epa.gov/sites/production/files/2015-09/documents/nedc-model-contract-sepcification.pdf.

Response G1-78.250

The EPA Clean Diesel Program is a grant program open to non-profit organizations, which is not available to Tesoro. Therefore, the EPA Clean Diesel Program is not a feasible mitigation measure. Mitigation measures A-5 and A-6 require the use of electrical equipment, where electricity is available in construction areas. Due to the flammability of gasoline, its use in Refinery construction equipment is limited for safety reasons. Mitigation Measure A-7 requires the use of Tier 4 off-road equipment for equipment greater than 50 hp. Therefore, cranes greater than 200 hp are included in Mitigation Measure A-7. As explained in Response G1-78.246, all equipment used during construction will use the cleanest equipment feasible and available. Therefore, all feasible mitigation suggested in the comment has been imposed.

Comment G1-78.251

- Use alternative diesel fuels, such as Clean Fuels Technology (water emulsified diesel fuel), or O2 diesel ethanol-diesel fuel (O2 Diesel) in existing engines;[392]
- Convert part of the construction truck fleet to natural gas;[393]

G1-78.251

- Include "clean construction equipment fleet", defined as a fleet mix cleaner than the state average, in all construction contracts;
- Fuel all off-road and portable diesel powered equipment with ARB-certified motor vehicle diesel fuel (non-taxed version suitable for use off-road);
- Use electric fleet or alternative fueled vehicles where feasible including methanol, propane, and compressed natural gas;
- Use on-road, heavy-duty trucks that meet the ARB's 2007 or cleaner certification standard for on-road diesel engines, and comply with the State on-road regulation;

G1-78.251 cont'd.

[392] SCAQMD, Mitigation Measure Resources, Construction Emissions Mitigation Measures, https://www.google.com/webhp?sourceid=chrome-instant&ion=1&espv=2&ie=UTF-8#q=scaqmd%20ceqa%20construction%20mitigation.

[393] This is a mitigation measure used by PG&E to offset NOx emissions from its Otay Mesa Generating Project. See: GreenBiz, Natural Gas Trucks to Offset Power Plant Emissions, September 12, 2000; Available at: http://www.greenbiz.com/news/2000/09/12/natural-gas-trucks-offset-power-plant-emissions.

Response G1-78.251

All feasible construction mitigation measures have been imposed. Alternative fuels can only be used in equipment designed to accommodate such fuels and could be detrimental to the equipment if used improperly. Therefore, the use of alternative fuels will be at the discretion of the contractors who maintain the equipment. The proposed project will comply with all state and federal clean diesel regulations (e.g., CCR, Title 13, Division 3, Chapter 5, Article 2 and 40 CFR Part 8, Subpart I). Electric vehicles are not widely available in the California construction industry. The proposed project includes many different activities over a large geographic area and over a long construction period. It is unreasonable to expect the many different contractors that will work on the proposed project and that are not directly controlled by Tesoro, to meet "clean construction equipment fleet" requirements or to replace vehicles with an electric fleet due to the high costs and limited availability of this equipment. As explained in Response G1-78.246, all equipment used during construction will use the cleanest equipment feasible and available, which could include the use of alternatively fueled equipment and the use of on-road diesel in construction equipment. Mitigation Measure A-3 requires that on-road heavy duty diesel trucks comply with 2007 on-road emission standards for NOx and PM as suggested in the comment.

Comment G1-78.252

- Use idle reduction technology, defined as a device that is installed on the vehicle that automatically reduces main engine idling and/or is designed to provide services, e.g., heat, air conditioning, and/or electricity to the vehicle or equipment that would otherwise require the operation of the main drive engine while the vehicle or equipment is temporarily parked or is stationary;[394]

- Minimize idling time either by shutting off equipment when not in use or limit idling time to 3 minutes (5 minutes is required by 13 CCR 2449[d][3], 2485, so is not "mitigation"). Signs shall be posted in the designated queuing areas and/or job sites to remind drivers and operators of the 3 minute idling limit. The on-site construction manager shall enforce this limit.

- Prohibit diesel idling within a buffer zone established by health risk assessment to protect sensitive receptors and use an on-site monitor to enforce this distance;

G1-78.252

[394] EPA Names Idle Reduction Systems Eligible for Federal Tax Exemptions, March 2009, Available at: http://www.greenfleetmagazine.com/channel/green-operations/article/story/2009/03/epa-names-idle-reduction-systems-eligible-for-federal-excise-tax-exemptions-grn.aspx. See also: Idle Reduction, Wikipedia; Available at: https://en.wikipedia.org/wiki/Idle_reduction and Diesel Emissions Reduction Program (DERA): Technologies, Fleets and Project Information, Working Draft Version 1.0; Available at: https://www.epa.gov/sites/production/files/2015-09/documents/420p11001.pdf.

Response G1-78.252

As explained in Response G1-78.246, all equipment used during construction will be the cleanest equipment feasible and available. Tesoro's contractors will use trucks with idle reduction technology when available and feasible.

As explained in Response G1-78.247, truck idling will be restricted to five minutes unless exempted and signage will be posted. No evidence has been provided that limiting idling to three minutes would provide environmental benefits over the five-minute limit in Mitigation Measures A-2 and A-4.

Pursuant to Mitigation Measures A-2 and A-4, all diesel idling will be limited to five minutes whenever feasible. Further, as explained in Response G1-78.258, the health risk impacts from construction at receptor locations (sensitive or worker) are below the CEQA health risk thresholds. Therefore, no additional mitigation is required.

Comment G1-78.253

- Staging and queuing areas shall not be located within a buffer zone established by health risk assessment to protect sensitive receptors and use an on-site monitor to enforce this distance
- The number of construction equipment operating simultaneously shall be minimized through efficient management practices to ensure that the smallest practical number is operating at any one time;
- The engine size of construction equipment shall be the minimum practical size;
- Catalytic converters shall be installed on gasoline-powered equipment;

G1-78.253

Response G1-78.253

As explained in Response G1-78.258, the health risk impacts from construction at receptor locations (sensitive or worker) are below the CEQA health risk thresholds. Therefore, no additional mitigation is required.

Coordinating construction activities for the proposed project is complex because it includes many different activities, conducted by different companies, over a large geographic area and over a long construction period. A limitation of the number of construction equipment operating simultaneously is not practical given the logistics of the proposed project.

As explained in Response G1-78.246, the appropriately sized equipment will be used to perform each task. Any additional or larger- sized equipment will not be used unless there are no other feasible options.

Mitigation Measure A-1 requires the maintenance of the Construction Management Program, which is designed to implement mitigation measures, implement applicable best management practices, use the cleanest equipment available, and manage equipment use efficiently.

As explained in Response G1-78.246, all equipment, including gasoline-powered equipment, will use the cleanest equipment whenever feasible and available.

Comment G1-78.254

- Signs shall be posted in designated queuing areas and job sites to remind drivers and operators of the idling limit;
- Engine size of construction equipment shall be the minimum practical size;
- The number of construction equipment operating simultaneously shall be minimized through efficient management practices to ensure that the smallest practical number is operating at any one time;
- Construction worker trips shall be minimized by providing options for carpooling and by providing for lunch onsite;

G1-78.254

Response G1-78.254

As explained in Response G1-78.247, idling will be restricted to five minutes and signage will be posted.

As explained in Response G1-78.246, the appropriately sized equipment will be used to perform each task. Any additional or larger-sized equipment will not be used unless there are no other feasible options.

As explained in Response G1-78.253, a limitation of the number of construction equipment operating simultaneously is not practical given the logistics of the proposed project.

Mitigation Measure A-1 requires the maintenance of the Construction Management Program, which is designed to implement mitigation measures, implement best management practices, use the cleanest equipment available, and manage equipment use efficiently.

The workforce employed for this project is temporary and will not be comprised of employees of Tesoro. Therefore, Tesoro cannot impose carpooling requirements on another workforce. Furthermore, allowing vendors onsite for lunch could compromise the security at the Refinery. However, Tesoro does provide space and shelter for the workforce to eat packed lunches onsite and the on-site cafeteria is available to the general public, including proposed project workers.

Comment G1-78.255

- Use new or rebuilt equipment;
- Maintain all construction equipment in proper working order, according to manufacturer's specifications. The equipment must be check by an ASE-certified mechanic and determined to be running in proper condition before it is operated;
- Use low rolling resistance tires on long haul class 8 tractor-trailers;[395]

G1-78.255

[395] EPA, Verified Technologies for SmartWay and Clean Diesel, Learn About Low Rolling Resistance (LRR) New and Retread Tire Technologies; Available at: https://www.epa.gov/verified-diesel-tech/learn-about-low-rolling-resistance-lrr-new-and-retread-tire-technologies; EPA, Verified Technologies for SmartWay and Clean Diesel, SmartWay Verified List for Low Rolling Resistance (LRR) New and Retread Tire Technologies; Available at: https://www.epa.gov/verified-diesel-tech/smartway-verified-list-low-rolling-resistance-lrr-new-and-retread-tire.

Response G1-78.255

As explained in Response G1-78.246, the equipment used during construction is not the property of Tesoro. However, Tesoro will contractually require the contractors and subcontractors to use the cleanest fleet feasible and available, a requirement that includes consideration of various aspects of equipment such as low-resistance tires for long haul deliveries. The vendors will also be contractually obligated to maintain the equipment according to the manufacturer specifications as required in the Best Management Practices included in the Construction Management Program in Mitigation Measure A-1. The requirement for an ASE certified mechanic to perform the equipment checks is unnecessary and unduly burdensome for the contractors.

ASE is the acronym for Automobile Service Excellence. ASE certification is applicable to the automotive industry and was developed to enable independent automobile service shops to maintain automobiles under manufacturer's warranty in lieu of requiring all maintenance to be performed at automobile dealerships. ASE certification is not required, nor applicable to maintenance of construction equipment.

Equipment operators or field supervisors will perform the required equipment checks. Therefore, the requested mitigation is already part of Mitigation Measure A-1 of the DEIR (see page 4-36 of the DEIR).

Comment G1-78.256

- Use diesel-electric and hybrid construction equipment.[396]
- Maintain all construction equipment in proper working order, according to manufacturer's specifications. The equipment must be check by an ASE-certified mechanic and determined to be running in proper condition before it is operated.

G1-78.256

[396] Tom Jackson, How 3 Diesel-Electric and Hybrid Construction Machines are Waging War on Wasted Energy, Equipment World, June 1, 2014; Available at: http://www.equipmentworld.com/diesel-electric-and-other-hybrid-construction-equipment-are-waging-war-on-wasted-energy/; Kenneth J. Korane, Hybrid Drives for Construction Equipment, Machine Design, July 7, 2009; Available at: http://machinedesign.com/sustainable-engineering/hybrid-drives-construction-equipment; Caterpillar's D7E Electric Drive Redefines Dozer Productivity; Available at: http://www.constructionequipment.com/caterpillars-d7e-electric-drive-redefines-dozer-productivity.

Response G1-78.256

As explained in Response G1-78.246, the equipment used during construction is not the property of Tesoro. However, Tesoro will contractually require the contractors and subcontractors to use the cleanest fleet feasible and available. The vendors will also be contractually obligated to maintain the equipment according to the manufacturer specifications as required in the Best Management Practices that are included in the Construction Management Program in Mitigation Measure A-1 (see Response G1-78.255). As explained in Response G1-78.255, it is infeasible to require inspection by a certified mechanic before each use. Therefore, the requested mitigation is already part of the DEIR (see pages 4-36 through 4-40 of the DEIR).

Comment G1-78.257

To assure the construction mitigation program is carried out, all off-road diesel-powered equipment should be tested to assure tailpipe emissions do not exceed 20% opacity for more than 3 minutes in any hour. Any equipment found to exceed 20% opacity must be repaired immediately. A visual inspection of all in-operation equipment must be made at least daily by the contractor and witnessed monthly or more frequently by the SCAQMD, and a periodic summary of the visual survey results must be submitted by the contractor throughout the duration of the project to the SCAQMD. The summary should include the quantity and type of vehicles inspected and dates.

All feasible mitigation must be required when an impact is significant and unavoidable. Thus, the EIR should be revised to include these additional mitigation measures and recirculated for public review.

G1-78.257

Response G1-78.257

The DEIR Mitigation Measure A-1 requires as part of the Construction Management Program, the implementation of the Best Management Practices outlined on page 4-40 of the DEIR. The Best Management Practices require the equipment to be maintained according to manufacturer's specifications. Maintenance in accordance with manufacturer's specifications would require that the equipment meet the opacity (density of airborne PM) requirements in SCAQMD Rule 401. While compliance requirements can be imposed as mitigation measures, compliance with regulations may also be considered part of the proposed project.[233] The SCAQMD has

[233] Citizens for a Sustainable Treasure Island v. City & County of San Francisco (2014) 227 Cal.App.4th 1036, 1059-60 (citing CEQA Guidelines § 15126.4(a)(1)(B)); see also Center for Biological Diversity v. Dept. of Fish & Wildlife (2015) 234 Cal.App.4th 214, 245-46 (compliance with federal regulations requiring a hatchery genetic management plan was an appropriate and sufficient measure meant to mitigate impacts on fish); Citizens Opposing a Dangerous Environment v. County of Kern (2014) 228 Cal.App.4th 360, 383 (obligation to observe

enforcement personnel who inspect facilities and enforce SCAQMD Rules and Regulations. As explained in the DEIR, only VOC and NOx construction emissions are significant; therefore, additional PM mitigation is not required to control opacity.

Comment G1-78.258

IX. HEALTH EFFECTS OF CONSTRUCTION EMISSIONS WERE NOT EVALUATED

The DEIR is silent on health impacts from construction of the Project.[397] Construction uses diesel-fueled, off-road equipment such as backhoes, bulldozers, paving equipment, and cranes. This equipment emits large amounts of diesel particulate matter or DPM, which is a potent carcinogen.

Construction is well known to result in significant health impacts in surrounding communities. In a study of construction health impacts in California,[398] the South Coast

G1-78.258

air basin where the Project is located, ranked first in California with the greatest construction health impacts, including more than 700 premature deaths, more than 650 hospitalizations for respiratory and cardiovascular illness, more than 1,700 cases of acute bronchitis, nearly 21,000 incidents of asthma attack and other lower respiratory symptoms, and over 300,000 days of lost work and school absences. This loss of life and productivity cost South Coast residents an estimated $5.9 billion.[399]

The DEIR has failed to evaluate the impact of Project construction on the health of nearby sensitive receptors. Thus, the DEIR fails as an informational document.

G1-78.258 cont'd.

397 DEIR, Appx. B-4.

398 Don Anair, Union of Concerned Scientists, Digging Up Trouble. The Health Risks of Construction in California, 2006, Figure 1. Available at: http://www.ucsusa.org/sites/default/files/legacy/assets/documents/clean_vehicles/digging-up-trouble.pdf.

399 *Id.*, pp. 1, 12, and Table 1.

Response G1-78.258

In March 2015, the OEHHA approved revised guidelines for estimating health risks. The revised OEHHA risk guidelines updated its cancer risk methodology to account for the susceptibility of infants and children to air toxics and also to modify assumptions for exposure durations. These updated guidelines also recommended performing health risk assessments on construction activities of greater than two months in duration.

In June 2015, the SCAQMD updated the AB258 Air Toxic "Hot Spots" Program and permitting Risk Assessment Guidelines to incorporate the updated OEHHA methodology. However, the SCAQMD is in the process of developing construction health risk assessment guidelines through a public participation process. As such, no formal guidance from OEHHA or SCAQMD on construction health risk assessments is available at this time.

Federal Aviation Agency rules and regulations was an appropriate mitigation measure for impacts to aviation safety).

Despite this absence of guidance, Tesoro has completed a health risk assessment regarding the diesel particulate emissions from the construction of the proposed project. This health risk assessment has been reviewed by the SCAQMD modeling staff and found to have adequately addressed the complexities of the proposed project's varying construction schedule. The construction HRA has made simplifying assumptions, such as having a piece of equipment that would normally be shared between two locations running concurrently in each location, which will result in overstating the risk (see Appendix H of the FEIR for the construction HRA report). The health risk assessment for construction emissions determined the construction health risk to be 2.9 in one million at the maximum residential receptor location and 2.5 in one million at the maximum worker receptor location. These locations differ from the maximum impact locations of the operational health risk assessment presented in the FEIR in Section 4.2.2.5. When assessing the maximum health risk for the combined construction and operational emissions, the result is not as simple as adding the maximum construction health risk to the maximum operational health risk, because, as previously mentioned, they can be at different locations. Instead, the risk at each receptor must be individually calculated.

Table 78.258-1 presents the construction, operational, and combined health risk results and Figure 78.258-1 shows the maximum impact locations. The results of the construction health risk analysis and the combined construction and operational health risk are below the SCAQMD significance threshold for operational health risks. Therefore, the additional information provided on the construction health risk does not substantially increase the severity of the health risk assessment or change the significance determination made in the DEIR on health risk.

Table 78.258-1

Construction, Operational, and Combined Health Risk Results

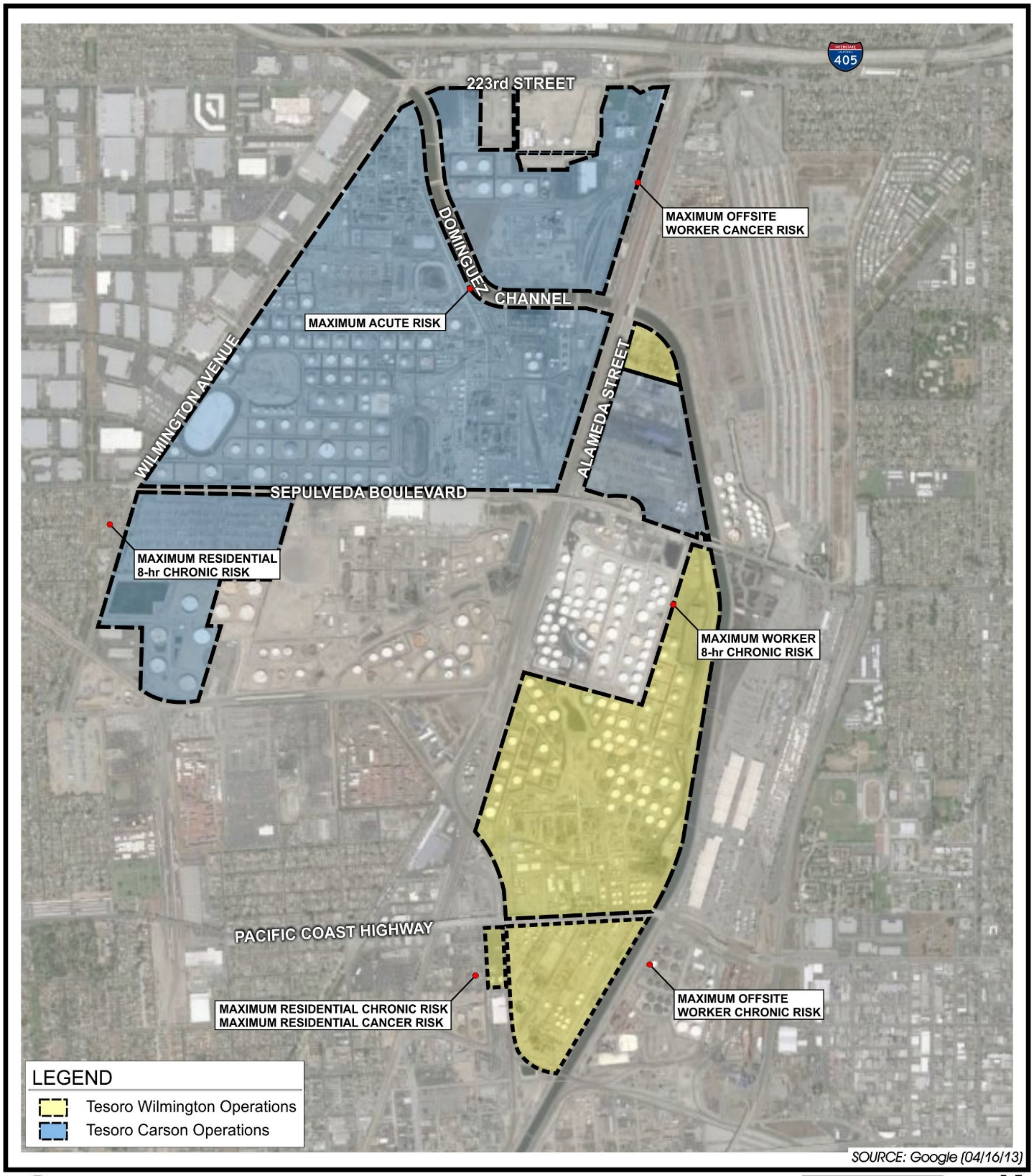
Receptor Location	Operations Only(a)		Construction Only(b)		Combined Construction and Operations(c)	
	Cancer Risk	Chronic HI	Cancer Risk	Chronic HI	Cancer Risk	Chronic HI
Resident	3.7×10^{-6}	0.066	2.9×10^{-6}	0.003	5.6×10^{-6}	0.069
Worker	9.3×10^{-6}	0.127	2.5×10^{-6}	0.017	9.3×10^{-6}	0.132

HI = hazard index

(a) Resident UTM Coordinates: 383700,3741400; Worker UTM Coordinates: 386005.9, 3742921.4

(b) Resident UTM Coordinates: 385251.4, 3739502.8; Worker UTM Coordinates: 384457.8, 3741374.6

(c) Resident UTM Coordinates: 385251.4, 3739502.8; Worker UTM Coordinates: 386005.9, 3742921.4



Environmental Audit, Inc.

FIGURE 78.258-1
MAXIMUM CALCULATED COMBINED
CONSTRUCTION AND OPERATIONS HEALTH RISK LOCATIONS
TESORO LOS ANGELES REFINERY

Project No. 2844

N:\2844\Maximum Calculated Health Risks.cdr

Comment G1-78.259

South San Francisco, CA 94080

Subject: Comments on theTesoro Los Angeles Refinery Integration and Compliance Project

Dear Ms. Koss:

I have reviewed the March 2016Draft Environmental Impact Report (DEIR) for the Tesoro Los Angeles Refinery Integration and Compliance Project ("Project"), which proposes: (1) reconfiguration of the combined refinery complex (Carson and Wilmington Operations) which will allow for the shuttering of the Fluid Catalytic Cracking Unit at the Wilmington Operations; (2) installing interconnecting pipelines; and (3) Installing new heat exchangers and modifying existing units.The Refinery includes the Wilmington Operations in the Wilmington District of the City of Los Angeles and the Carson Operations in the City of Carson.

I have found the DEIR to inadequately disclose contaminated soil and groundwater conditions. As a result, construction worker health may be compromised during construction and water quality impacts may result. A revised DEIR must be prepared to disclose contaminants in the subsurface and to include mitigation measures that will ensure worker safety and environmental protection provisions.

G1-78.259

Response G1-78.259

The comment is a summary statement regarding the disclosure of potential soil and groundwater contamination and worker protection. The concerns raised in the comment are provided in more detail in Comments G1-78.260 through 78.264 and responded to in detail in the subsequent response as noted below. The comment does not provide any supporting information or further details that explain why the disclosure and discussion of potential soil contamination and ground water conditions in the DEIR was inadequate.

The DEIR has fully disclosed and analyzed soil and groundwater impacts of the proposed project in Sections 3.3.5 and 4.3.2.6 of the DEIR. The construction phase of the proposed project will require construction workers to excavate soil across the Wilmington Operations, primarily the southeastern portion of the Carson Operations, and the Carson Crude Terminal, where construction of the new crude oil storage tanks will occur. As indicated in Section 3.3.5, soil samples were collected in areas of the Refinery where construction of the proposed project is to take place to characterize the soil for disposal purposes (i.e., hazardous or non-hazardous waste designation). Of the 44 soil samples analyzed, samples indicate that 95 percent of the soil to be potentially excavated will be classified as non-hazardous waste. During the soil sampling activities, air sampling consistent with SCAQMD Rule 1166 was performed. Two areas where proposed project construction is planned (at the Wilmington Operations in the vicinity of the 24-inch piping associated with the two replacement storage tanks and in the vicinity of HCU) have been shown to have shallow contamination which may have VOC concentrations that exceed the SCAQMD Rule 1166 criterion of 50 ppm, which requires excavated soil to be containerized and removed from the site. Existing site characterization data showing contaminated soil sites will be supplemented with sample data from pre-project exploratory borings conducted throughout the construction zone and will be used to develop a project-specific Soil Management Plan.

Furthermore, as explained in Section 3.3.5 on page 3-25 of the DEIR, the Refinery has implemented ongoing remedial programs under Los Angeles RWQCB Cleanup and Abatement Orders CAO 90-121, CAO 88-70 and CAOR4-2011-0037. See also Response to Comment

G1-78.260. The DEIR analyzed/evaluated the potential for exposure during excavation and construction by examining soil samples collected at the proposed project site and concluded that the regulations and programs with which the Refinery must comply, as well as the safety training that workers currently receive will prevent or minimize any impacts to workers from existing soil and groundwater contamination. Any contamination encountered during the construction of the proposed project will be managed consistent with the existing programs for the Refinery, and impacts to workers are less than significant.

Comment G1-78.260

Contaminants in Soil and Groundwater are Inadequately Disclosed

The refinery has a long history of releases of contaminants to soil and groundwater from operations. As a result, the Los Angeles Regional Water Quality Control Board has issued Cleanup and Abatement Orders for the Carson Operations (CAO 90-121) and the Wilmington Operations (CAO 88-70 and CAO R4-2011-0037). Monitoring and remediation efforts under these orders are ongoing. G1-78.260

Soil contamination and contamination of the groundwater with a light non-aqueous phase liquid (LNAPL) at the Carson and Wilmington Operations were documented in a 2015 report that was referenced in the DEIR.[1] In summarizing the results of this report, the DEIR states (p. 3-25):

> Of the 44 soil samples analyzed, samples indicate that 95 percentof the soil to be potentially excavated will be classified as non-hazardous waste. During the soil sampling activities, air sampling consistent with SCAQMD Rule 1166 was performed.

G1-78.260 cont'd.

The DEIR makes no conclusions about impacts of the Project on worker health when contaminated soils and groundwater are encountered during excavation. Simply comparing the results to hazardous waste and air emissions criteria is inappropriate for disclosure of conditions that may impact construction workers who touch contaminated soil or who breathe contaminated vapors. Health risks should be estimated in a revised DEIR by comparing soil sampling results to screening levels that are health protective of construction workers as published in the widely used San Francisco Bay Regional Water Quality Control Board Environmental Screening Levels (ESLs).[2]

[1] Soil Characterization, Tesoro Refinery Integration Project, 2350 East 223rd Street, Carson, California, Trihydro Corp., January 5, 2015

[2] http://www.waterboards.ca.gov/sanfranciscobay/water_issues/programs/ESL/ESL%20Workbook_ESLs_PDF_Rev2.pdf, "Any Land Use/Any Depth Soil Expsoure: Construction Worker"

Response G1-78.260

The DEIR analysis appropriately characterized the site, based upon soil sampling, and presented the information on the known contamination at the Refinery in Sections 3.3.5 and Sections 3.3.5.1 and 3.3.5.2 as part of the Environmental Setting of the DEIR. As explained in Section 4.3.2.6 of the DEIR on pages 4-61 through 4-66, the analysis describes the numerous existing rules, regulations, and requirements related to hazards with which the project must comply, and provides support for the fact that construction workers are professionally trained and equipped with safety equipment to safely work around the potentially hazardous conditions that are known to exist within the Refinery. The DEIR concludes on page 4-63 that "Compliance with these laws will ensure that any off-site receptor or worker exposure is less than significant." As the comment points out, the Refinery has engaged in ongoing remediation activities of the contaminated soil and groundwater under the jurisdiction of the Los Angeles Regional Water Quality Control Board. The regulations (e.g., HAZWOPER) set forth procedures to protect workers as well as off-site receptors from exposure to contaminated soil and groundwater.

Therefore, the DEIR has presented an adequately supported conclusion regarding the potential impacts of the proposed project on construction workers, and the comment does not provide technical support or detail as to why the conclusion is not correct.

The comment suggests that a particular metric, the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB) Environmental Screening Levels (ESLs)[234], should have been used to estimate health risks to construction workers. As explained above, because the DEIR characterized and disclosed the impacts, this further health risk analysis is not required by CEQA. Even if it were, this particular method would not be necessary or appropriate. As stated in the Disclaimer to the SFBRWQCB ESLs User's Guide, "Use of the ESLs by dischargers or regulators is optional" and in the Executive Summary, "The ESLs allow dischargers and regulators <u>in our region</u> [emphasis added, the San Francisco Bay area] to quickly focus on the most significant problems at contaminated sites." The SFBRWQCB ESLs are designed based on unique regional conditions. Therefore, the use of the SFBRWQCB ESLs was not intended to be widely-used throughout the state as the comment claims. The state is divided into regions to account for differences throughout the state (e.g., geology, soil characteristics, groundwater characteristics) and each RWQCB can establish standards applicable in the respective region. Furthermore, worker exposure and safety training are regulated by California Occupational Safety and Health Administration (CalOSHA) regulations that are required to be adhered to by the employer. CalOSHA regulations establish Permissible Exposure Limits (PELs) that are protective of workers for both acute and chronic health effects.

Comment G1-78.261

To estimate potential health risks to construction workers, we compared results included in the 2015 soil sampling report to the construction worker soil exposure ESLs. We found two things: (1) exceedances of the construction worker ESLs were found near areas where Project construction will take place and; (2) with a couple of exceptions, samples were not collected where Project improvements are likely to disturb soil and sampling density was woefully inadequate to characterize soil contamination. G1-78.261

Response G1-78.261

As explained in Response G1-78.260, further health risk analysis is not required and the comment has misapplied the SFBRWQCB ESLs to the proposed project, which is not located in the San Francisco Bay area. Further, as stated in the Disclaimer of the SFBRWQB ESL User's Guide, "The presence of a chemical at concentrations in excess of an ESL does not necessarily indicate adverse effects on human health or the environment, rather that additional evaluation is warranted." The DEIR has provided analysis of the nature and extent of site contamination, and the safety measures and regulations that workers must follow. Moreover, the comment provides no evidence to support the conclusion made that the existing soil and groundwater contamination would exceed the SFBRWQCB ESLs. Therefore, the accuracy of the conclusions made in the

[234] User's Guide: Derivation and Application of Environmental Screening Levels, SFBRWQCB, February , 2016, http://www.waterboards.ca.gov/sanfranciscobay/water_issues/programs/ESL/ESL%20Users%20Guide_22Feb16.pdf.

comment cannot be verified. As also explained in Response G1-78.260, construction workers at the Refinery are professionally trained and equipped to safely work around the potentially hazardous conditions that exist within a refinery and numerous laws, regulations, and requirements are in place to protect workers. The SFBRWQCB ESLs do not account for worker training and protective equipment that would prevent exposures to contamination during construction.[235]

The soil characterization activities relied upon in the DEIR were performed in areas of the proposed project where prior soil characterization had not been performed during the remediation efforts overseen by the Los Angeles Regional Water Quality Control Board. As such, when combined with previous data explained in Section 3.3.5 of the DEIR, sufficient information was available to characterize the soil expected to be encountered during the proposed project and the DEIR appropriately concluded the impacts from soil and groundwater contamination would be less than significant (see also Section 4.3.2.6 of the DEIR).

Comment G1-78.262

ESL Exceedances

The maps we prepared(below) show where soil ESLs for construction workers will be exceeded near where soil will be excavated. This indicates the potential for soil in the areas for construction of the Project to also exceed construction worker ESLs. G1-78.262

G1-78.262 cont'd.

[235] User's Guide: Derivation and Application of Environmental Screening Levels, SFBRWQCB, February , 2016, http://www.waterboards.ca.gov/sanfranciscobay/water_issues/programs/ESL/ESL%20Users%20Guide_22Feb16.pdf, pg. 1-11 last bullet.

G1-78.262 cont'd.

Health effects of the compounds detected above ESLs at the Wilmington and Carson Operations include:

> TPH: Some TPH compounds, affect the central nervous system, causing headaches and dizziness, a nerve disorder called "peripheral neuropathy," and effects on the blood, immune system, lungs, skin, and eyes. Animal studies have shown effects on the lungs, central nervous system, liver, and kidney from exposure to TPH compounds. Some TPH compounds have also been shown to affect reproduction and the developing fetus in animals.[3]
>
> Mercury:Exposure to high levels of metallic, inorganic, or organic mercury can permanently damage the brain, kidneys, and developing fetus. Short-term exposure to high levels of metallic mercury vapors may cause effects including lung damage, nausea, vomiting, diarrhea, increases in blood pressure or heart rate, skin rashes, and eye irritation.[4]

The DEIR did not disclose or mitigate the Project's potentially significant health impacts on construction workers from the excavation of contaminated soils.

[3]http://www.atsdr.cdc.gov/toxfaqs/tf.asp?id=423&tid=75
[4]http://www.atsdr.cdc.gov/toxfaqs/TF.asp?id=113&tid=24

Response G1-78.262

No evidence was provided in the comment to verify the accuracy of the graphic depictions or any supporting calculations of ESL results and thus, the opinion in the comment is unsubstantiated. As explained in Responses G1-78.260 and G1-78.261, the SFBRWQCB ESLs are not applicable in the Los Angeles area. The DEIR analyzed and correctly determined the proposed project impacts related to soil and groundwater contamination are less than significant.

The purpose of conducting preliminary sampling is to identify areas where potential construction may encounter contamination and allow for the construction team to prepare, appropriately train workers, and provide the proper personal protective equipment to workers in areas where the potential for exposure has been identified. In addition to the known contamination at the Refinery, the soil characterization activities relied upon in the DEIR were performed in areas of the proposed project where prior soil characterization had not been performed and where construction was expected. Therefore, the DEIR provides sufficient information to determine and mitigate potential impacts.

Comment G1-78.263

Sampling Density is Inadequate

The maps above, while indicating the potential for exceedances in areas of Project construction also depict inadequate sampling where earthmoving activities are to take place. The maps show that sampling was not targeted to the Project and is therefore inadequate as a basis for decision making about potential hazards.

The 2015 report purported sampling in "the locations where soil will be generated during the Integration Project" (p. 1). The maps we prepared show, instead, that very few samples were collected in areas where Project improvements will be made.

Because sampling did not successfully target areas of Project improvements, potential soil contamination in those areas has not been adequately disclosed. A DEIR must be prepared to include the results of a sampling investigation in areas to be excavated. Comparison of the results to construction worker ESLs should also be included. Any exceedances of the ESLs should be mitigated by ensuring proper personal protective equipment, including gloves, respirators and protective suits. G1-78.263

We also prepared a map to show where a pipeline "bundle" would be completed under the Alameda Corridor and Sepulveda Boulevard as part of the work that will connect pipelines between the Wilmington and Carson Operations. The pipeline bundle will require a 54-inch bore using horizontal directional drilling to advance80 feet underneath South Alameda Street and East Sepulveda

Boulevard.

The figure we prepared shows the underground pipeline bundle to cross through or near a pool of LNAPL to the east of Alameda Street and directly east of theDominguez Channel. The LNAPL, as measured in October of 2013, was 0.74 feet thick and found at a depth of approximately 14 feet.[5] Because the pipeline bundle would extend 80 feet below ground in this area, the pipeline has the potential to penetrate the LNAPL in this vicinity.

G1-78.263 cont'd.

[5] Semi-Annual Groundwater Monitoring Report, Second Semester, 2013, URS, January 14, 2014, Table 4

Response G1-78.263

No documentation was provided in the comment to verify the accuracy of the information provided in the maps regarding soil sampling. As explained in Response G1-78.261, the soil characterization activities relied upon in the DEIR were performed in areas of the proposed project where prior soil characterization had not been performed during the remediation efforts overseen by the Los Angeles RWQCB (see Sections 3.3.5 and 4.3.2.6 of the DEIR). There was no need to sample in areas of known contamination where on-going remediation is taking place, because that information was already available,.and was utilized in the DEIR's analysis as well. The conclusions in the DEIR regarding potential hazards associated with soil and groundwater contamination are thus supported by this adequately disclosed and reasonable sampling method.

As described in Section 3.3.5 on page 3-25 of the DEIR, the Refinery has implemented ongoing remedial programs under Los Angeles RWQCB Cleanup and Abatement Orders CAO 90-121, CAO 88-70 and CAOR4-2011-0037. See also Response to Comment G1-78.260. The regulations and programs with which the Refinery must comply, as well as the safety training that workers receive will prevent or minimize any impacts to workers from soil and groundwater contamination. As described in Section 4.3.2.6 of the DEIR, any contamination encountered during the construction of the proposed project will be managed consistent with the existing programs for the Refinery, and exposure to workers will be less than significant.

The figure provided in the comment does not show a scale and inaccurately depicts the size of the pipeline bundle. Figure 78.263-1, which is drawn to scale, accurately depicts the diameter for the bore of the pipeline bundle. As shown in Figure 78.263-1, the pipeline bundle is not expected to intersect with the known contamination in the area of wells H-99 and H-101.

Comment G1-78.264

No assessment was made in the DEIR about penetrating the LNAPL with the pipeline bundle and the environmental impacts that would result. Environmental impacts that must be considered and mitigated where necessary in a revised EIR include:

- Potential to smear the LNAPL to deeper depths when penetrated by the pipeline bundle. As drilling advances, the 54-inch bore may intersect the LNAPL and drag down relatively shallow contaminants to deeper levels, potentially further contaminating soil and groundwater.
- Potential need to dewater and the need to handle the LNAPL and the contaminated groundwater associated with the LNAPL. In Los Angeles, dewatering is regulated by Order R4-

G1-78.264

2013-0095[6] and requires conformance with a "General Permit" wherebythe discharger must submit a Notice of Intent andobtain authorization for a discharge under anappropriate monitoring and reporting program. A revised DEIR must acknowledge these requirements and show how the Project will comply.
- Special needs for worker health and safety associated with potential need to physically handle the LNAPL, which may include pure gasoline, diesel fuel, jet fuel, fuel oil or a mixture of these compounds. A revised DEIR should include, as mitigation, measures to protect workers from direct contact with the LNAPL and from exposure to vapors.

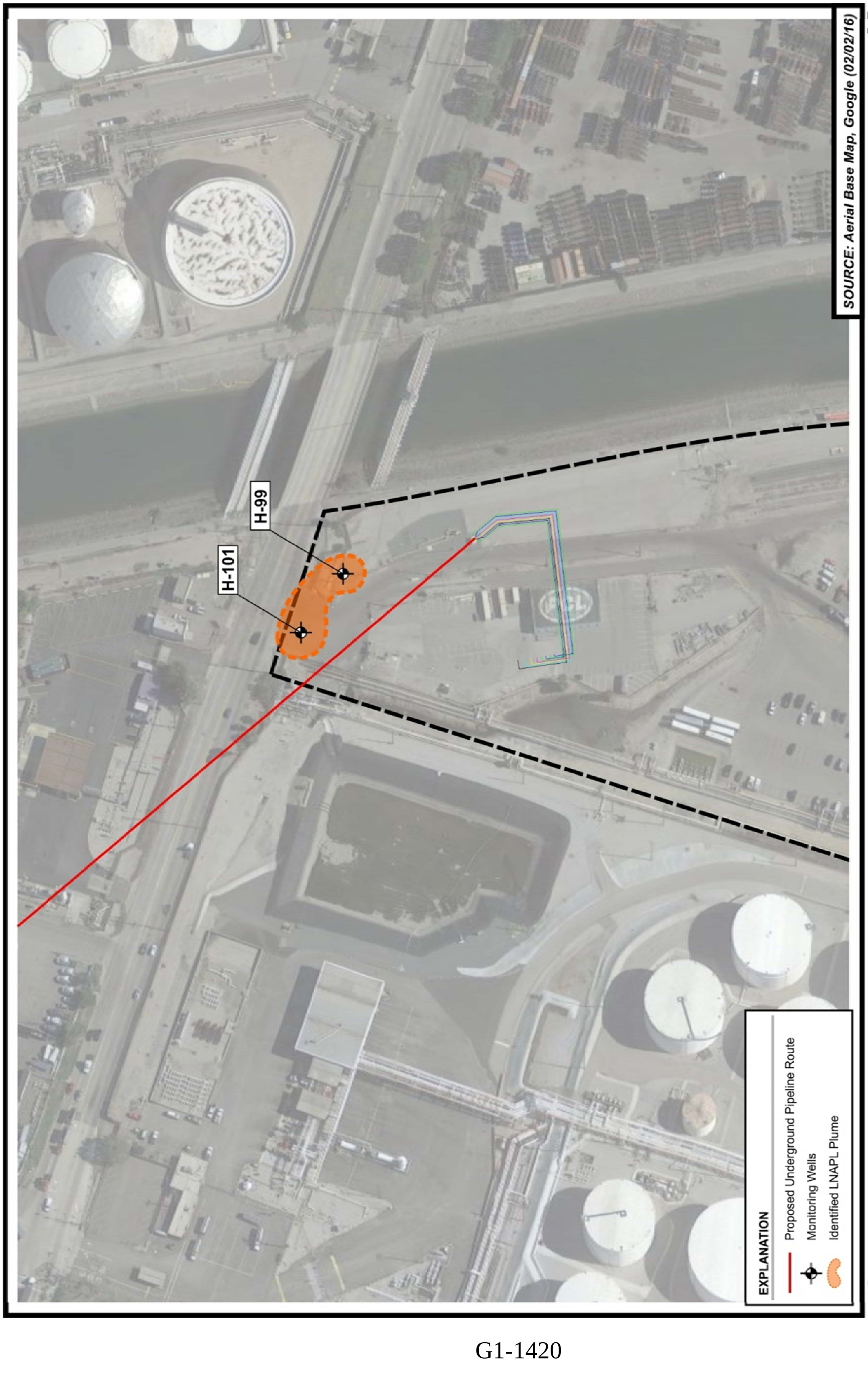
G1-78.264 cont'd.

[6]http://www.waterboards.ca.gov/losangeles/board_decisions/adopted_orders/permits/general/npdes/r4-2013-0095/Dewatering%20Order.pdf

Response G1-78.264

As explained in Response G1-78.260, the DEIR analyzes the effects of the proposed project on the environment. As explained in Section 4.3.2.6 of the DEIR, no significant impacts to soil and groundwater or to workers and residents from disturbance of contaminated soil or groundwater were identified. See Response G1-78.263 regarding potential impacts on areas of contaminated liquid. The Refinery has implemented ongoing remedial programs under Los Angeles RWQCB Cleanup and Abatement Orders CAO 90-121, CAO 88-70 and CAOR4-2011-0037, has procedures in place for proper handling and disposal of contaminated soil and groundwater, when encountered, and will follow all applicable rules and regulations that limit worker exposure to soil and groundwater contamination. Any contaminated soil or groundwater encountered during construction of the proposed project will be managed in accordance with existing Management Plan for Excavated Soil in place at the Refinery that complies with the applicable laws and regulations. As such, the DEIR fully assessed the impacts of the proposed project on geology and soils and hazards and hazardous materials and appropriately concluded the impacts to be less than significant. Where a proposed project's environmental effect is found to be less than significant, the EIR need not describe associated mitigation measures.[236]

[236] CEQA Guideline § 15126.4(a)(3).



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Environmental Audit, Inc.

FIGURE 78.263-1
PROPOSED PIPELINE ROUTE AND KNOWN LNAPL PLUME
TESORO WILMINGTON OPERATIONS

Project No. 2844
N:\2844\Overlay_Pipeline Overlay.cdr

Comment Letter No. G1-79

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June 10, 2016

VIA EMAIL AND U.S. MAIL

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Re: **Comments on the Proposed Title V Significant Permit Revisions for Tesoro Refining & Marketing Co. LLC's Carson and Wilmington Sites (Facility ID Nos. 174655 and 800436)**

Dear Mr. Luong:

We are writing on behalf of Safe Fuel and Energy Resources California ("SAFER California"), Peter Estrada, Leonardo Parra and Nicolas Garcia to provide comments on the South Coast Air Quality Management District's ("Air District") proposed Title V Significant Permit Revisions for Tesoro Refining & Marketing Co. LLC's ("Applicant") Carson and Wilmington sites (Facility ID Nos. 174655 and 800436, respectively). To implement its proposed Los Angeles Refinery Integration and Compliance Project ("Project"), the Applicant submitted 13 applications for revisions to the Title V permits for its Carson site (567643, 567645, 567646, 567647, 567648, 567649, 575837, 575838, 575839, 575840, 575841, 578248 and 578249) and five applications for revisions to the Title V permits for its Wilmington site (567619, 567439, 575874, 575875 and 575876). G1-79.1

The Project will interconnect operations at the two sites. Among other components, the Project will increase processing capability at the Wilmington site by 6,000 barrels per day by increasing the firing rate of Heater H-100 which serves the fractionator column of the Delayed Coking Unit at the Wilmington site. In addition, the Project would increase the capacity of the Hydrocracker Unit at the Carson site by approximately 10 percent. The Project also includes modifications to

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the Liquified Petroleum Gas ("LPG") Railcar Loading/Unloading Rack, enabling the Carson site to unload an additional 4,000 barrels per day of LPG. G1-79.1 cont'd.

The modifications covered in the proposed Title V Significant Permit Revisions cover only a fraction of the changes described in the Air District's Draft Environmental Impact Report ("DEIR") for the Project. Specifically, the proposed Title V revisions cover two heaters (Wilmington Heater H-100 and Carson No. 51 vacuum heater), the shutdown of the Wilmington FCCU, additions of various non-emitting equipment, modifications to the No. 5 Flare System, and various fugitive emission sources. There are numerous remaining components of the Project that are not covered in the proposed Title V revisions.

We reviewed the Air District's proposed Title V revisions with the help of technical expert Phyllis Fox, Ph.D., QEP, PE, DEE[1] and found that: (1) the proposed Title V modifications for both the Wilmington and Carson Operations are inconsistent with many of the assumptions used in the DEIR to analyze the change in emissions from the Project; and (2) that the modifications for both the Wilmington and Carson Operations allow much higher emission increases of NOx than assumed in the DEIR. If the Title V emissions changes were used in the DEIR's operational emission analysis, the Project would result in significant emission increases of NOx.[2] Therefore, either the Air District must revise the Title V permits to ensure that the assumed emission reductions in the DEIR are achieved, or the Air District must revise the DEIR to use the Project's correct emission increases. G1-79.2

I. STATEMENT OF INTEREST

SAFER California advocates for safe processes at California refineries to protect the health, safety, the standard of life and the economic interests of its members. For this reason, SAFER California has a strong interest in enforcing environmental laws which require the disclosure of potential environmental impacts of, and ensure safe operations and processes for, California oil refineries. Failure to adequately address the environmental impacts of crude oil and fuel products transport, refining, storage and distribution processes poses a substantial G1-79.3

[1] Dr. Fox's comments and curriculum vitae are attached and submitted in addition to the comments in this letter.

[2] The DEIR concluded that the Project would not result in any significant changes in emissions (see DEIR, Table 4.2-4).

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threat to the environment, worker health, surrounding communities, and the local economy.

Refineries and fuel storage and distribution facilities are uniquely dangerous and capable of generating significant fires and the emission of hazardous and toxic substances that adversely impact air quality, water quality, biological resources and public health and safety. These risks were recognized by the Legislature and Governor when enacting SB 54 (Hancock). Absent adequate disclosure and mitigation of hazardous materials and processes, refinery workers and surrounding communities may be subject to chronic health problems and the risk of bodily injury and death.

Poorly planned refinery and fuel products storage and distribution projects also adversely impact the economic wellbeing of people who perform construction and maintenance work in these facilities and the surrounding communities. Plant shutdowns in the event of accidental release and infrastructure breakdown have caused prolonged work stoppages. Such nuisance conditions and catastrophic events impact local communities and can jeopardize future jobs by making it more difficult and more expensive for businesses to locate and people to live in the area. The participants in SAFER California are also concerned about projects that carry serious environmental risks and public service infrastructure demands without providing countervailing employment and economic benefits to local workers and communities.

The members represented by the participants in SAFER California live, work, recreate and raise their families in Los Angeles County, including in or near the City of Carson and the community of Wilmington. Accordingly, these people would be directly affected by the Project's adverse environmental impacts. The members of SAFER California's participating unions may also work at the facility itself. They will, therefore, be first in line to be exposed to any hazardous materials, air contaminants, and other health and safety hazards, that exist onsite.

These comments are also submitted on behalf of individuals who reside and/or work in the Project area, including Peter Estrada, Leonardo Parra and Nicolas Garcia.

G1-79.3 cont'd.

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II. WILMINGTON TITLE V PERMIT MODIFICATIONS

A. The Proposed Modifications to the DCU H-100 Heater would Increase Daily Criteria Pollutant Emissions

The Project increases the firing rate of heater H-100 by 20 percent, from the design heat release basis of 252 MMBtu/hr to the maximum heat release basis of 302.4 MMBtu/hr.[3] The increased firing rate will increase emissions (in direct proportion).[4] Notably, however, the DEIR concluded that the increased firing rate would ***reduce*** emissions of all criteria pollutants except for SOx. Dr. Fox explains in her attached comments that the Air District achieved these reductions by artificially inflating the baseline emissions.[5]

The DEIR reports the following emissions reductions for heater H-100: G1-79.4

- NOx: -171.03 lbs/day
- CO: -5.14 lbs/day
- PM10: -0.98 lb/day
- PM2.5: -0.98 lb/day
- VOC: -0.43 lb/day

The Air District must revise the Title V permit to impose enforceable emission limits ensuring that these reductions are achieved, and the Air District must revise the DEIR to correct the heater H-100 emission calculations using the correct baseline (daily average emissions in the years 2012 and 2013, ***not*** the 98th percentile of the maximum emissions).

Further, the application for the heater H-100 firing rate states that, "Tesoro does not propose to increase the potentials to emit for this heater."[6] Yet, as Dr. Fox points out, "the proposed daily SOx limit of 250 lbs/day and the proposed daily ROG limit of 35 lbs/day are much higher than the potential to emit for heather H-100."[7] G1-79.5
The 8 lbs/day difference between the proposed ROG limit and potential to emit (27 lbs/day) tips the total Project ROG emissions of 49.09 lbs/day over the Air District's

[3] DEIR, pp. 1-11, 1-12.
[4] **Attachment A**: Letter from Dr. Phyllis Fox to Rachael Koss, June 9, 2016, p. 3 ("Fox Comments").
[5] *Id.*
[6] SCAQMD Application 567439, pdf 14.
[7] Fox Comments, p. 3.

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CEQA significance threshold of 55 lbs/day.[8] Notably, the DEIR operational emissions analysis assumes that the H-100 duty bump would *reduce* VOC emissions. Contrary to its application, Tesoro does, indeed, propose to increase the potentials to emit for heater H-100, and the proposed Title V permit does nothing to ensure that the emission assumptions in the DEIR are achieved.

G1-79.5 cont'd.

B. Permit Conditions A195.XX and A195.YY Allow for Exceedances of 1-Hour NOx and SOx Ambient Air Quality Standards

Draft permit Condition S11.X sets an hourly limit on NOx of 18.4 lbs/hr and on SOx of 14.08 lbs/hr. These hourly emission limits are consistent with emissions used in the criteria pollutant air quality modeling for heater H-100.[9] However, Dr. Fox points out that other conditions in the draft permit "weaken these limits by specifying an averaging time that allows exceedances of these 1-hour limits to be averaged out."[10] Specifically, Condition A195.XX provides that compliance with the "hourly" NOx limit is based on a rolling 24-hour average. Similarly, Condition A195.YY provides that compliance with the 1-hour SOx limit is based on a rolling 24-hour average. According to Dr. Fox, "[t]his type of averaging convention allows much higher hourly emissions than were assumed in the criteria pollutant modeling, which was performed to demonstrate compliance with ambient air quality standards."[11] Dr. Fox goes on to explain that a rolling 24-hour average "smooths out emissions data and eliminates peak hourly values that would otherwise exceed the hourly values used in the air dispersion modeling analysis and limited in Condition S11.X."[12] A rolling 24-hour average "guts the intent of the 1-hour limit in Condition S11.X. which is essential to assure that hourly average ambient air quality standards are not exceeded."[13]

G1-79.6

Dr. Fox points out that this problem is particularly critical for NOx. This is because the DEIR reports a 1-hour average NOx concentration of 301.4 ug/m^3, compared to the State 1-hour ambient air quality standard of 339 ug/m^3. The DEIR also reports a total 1-hour average NOx concentration of 184.9 ug/m^3, compared to the federal 1-hour ambient air quality standard of 188 ug/m^3. The values reported in the DEIR are very close to the State and federal standards. Thus, if the modeled

G1-79.7

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[8] *Id.*
[9] *Id.*
[10] *Id.*, p. 4.
[11] *Id.*
[12] *Id.*
[13] *Id.*

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NOx concentration increased by just 3.2 ug/m^3, from 38.6 ug/m^3 to 41.8 ug/m^3, the total NOx concentration would exceed the federal 1-hour NOx standard.[14] According to Dr. Fox, given the Air District's proposed permit conditions allowing the use of a 24-hour rolling average, it "is readily foreseeable" that the total NOx concentration would exceed the federal 1-hour NOx standard.[15] In Dr. Fox's opinion, the rolling 24-hour average may also allow violations of the 1-hour SOx State (655 ug/m^3) and federal (196 ug/m^3) ambient air quality standards.[16] The proposed 24-hour averaging times allows potentially significant unmitigated air quality impacts. Therefore, the Air District must eliminate the rolling average conventions in Conditions A195.XX and A195.YY.

G1-79.7 cont'd.

C. Proposed Permit Condition A99.X Allows for Exceedance of Hourly NOx Limit

Proposed permit Condition A99.X sets an exception to the new 18.40 lbs/hr hourly NOx limit as follows:

> The 18.40 lb/hr NOx emission limit(s) shall not apply during the heater startup, shutdowns or refractory dryout periods. For the purpose of this exception, each startup event shall not exceed 48 hours, not including refractory dryout period up to 48 additional hours and each shutdown event shall not exceed 24 hours.

G1-79.8

Dr. Fox explains that this exception is problematic for three reasons. First, it "would allow unlimited increases in NOx emissions, sufficient to violate the State and federal 1-hour NOx ambient air quality standards."[17] Second, automatic exemptions from permit limits during startup and shutdowns are not permitted.[18] Finally, the DEIR did not evaluate the impact of this exception (i.e., exemptions from hourly NOx limits) on ambient air quality.[19] Therefore, the Air District must eliminate the exception in Condition A99.X.

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[14] *Id.*
[15] *Id.*
[16] *Id.*
[17] *Id.*, p. 5.
[18] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir. Dec. 19, 2008).
[19] Fox Comments, p. 5.

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D. Stack Tests are Insufficient to Ensure Compliance with Emission Limits

The draft permit provides that compliance with the emission limits for PM10, ROG and CO would be determined using an annual stack test,[20] while compliance with NOx and SOx limits would be based on the use of a continuous emission monitoring system ("CEMS"). Dr. Fox explains that "annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions."[21] Since CEMS are available for ROG and CO, Dr. Fox recommends that CEMS be required to determine compliance with the proposed ROG and CO emission limits.[22] Dr. Fox points out that accurately verifying compliance with the ROG limit is particularly important because the Air District "is in serious nonattainment with ozone ambient air quality standards."[23] G1-79.9

III. CARSON TITLE V PERMIT MODIFICATIONS

A. The Proposed Permits Allows for Greater Emissions from the Carson No. 51 (D63) Vacuum Unit Heater than Were Analyzed in the DEIR

The Applicant proposes to modify Carson No. 51 Vacuum Unit Heater (D63) to increase the maximum permitted firing rate from 276.95 MMBtu/hr to 360 MMBtu/hr.[24] The increase in firing rate will increase emissions.[25] The draft permit sets new limits in Conditions A99.X1 (startup and shutdown exemption), A195.X1 (NOx 24 hr average), B61.8 (fuel gas H_2S limit), C1.X1 (heat input limit) and D29.X1 (test methods). The draft permit sets the following emission limits for the vacuum unit heater: G1-79.10

- CO: 29.6 lbs/MMSCF[26] natural gas
- PM: 6.3 lbs/MMSCF natural gas
- VOC: 5.9 lbs/MMSCF natural gas

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[20] Wilmington Draft Title V Permit, Condition A63.XX.
[21] Fox Comments, p. 5.
[22] *Id.*
[23] *Id.*
[24] DEIR, p. B-3-56.
[25] Fox Comments, p. 6.
[26] MMSCF = millions of standard cubic feet.

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- NOx: 2.62 lbs/day natural gas.[27]

Dr. Fox converted these limits into pounds per day, assuming the maximum firing rate of 360 MMBtu/hr and the higher heating value of natural gas (1050 MMBtu/MMSCF):

- CO: 244 lbs/day (DEIR:247 lbs/day)
- PM: 52 lbs/day (DEIR: 53 lbs/day)
- VOC: 48 lbs/day (DEIR: 50 lbs/day)
- NOx: 2.62 lbs/day (DEIR: 3.93 lbs/day)

These are consistent with the limits in Condition A63.3. However, Dr. Fox points out that these limits allow greater emissions than were analyzed in the DEIR.[28] Thus, the Air District must adjust the limits to reflect the DEIR analysis.

G1-79.10 cont'd.

The proposed permit further allows for greater emissions from the vacuum unit heater than were analyzed in the DEIR because: (1) Condition A99.X1 exempts the 2.62 lbs/hr NOx limit during startup and shutdowns for up to 48 hours; and (2) Condition A195.X1 specifies that the 2.62 lbs/hr limit is based on a 24-hour rolling average. The startup and shutdown exception is problematic for three reasons. First, it could cause violations of the State and federal 1-hour NOx ambient air quality standards.[29] Second, automatic exemptions from permit limits during startup and shutdowns are not permitted.[30] Finally, the DEIR did not evaluate the impact of this exception (i.e., exemptions from hourly NOx limits) on ambient air quality.[31] Therefore, the Air District must eliminate the exception in Condition A99.X1. The 24-hour rolling average is problematic because it allows much higher NOx emissions than assumed in the DEIR. According to Dr. Fox, these higher NOx emissions could cause violations of the State and federal 1-hour NOx ambient air quality standards, and exceed the Air District's 55 lbs/day NOx CEQA significance threshold.[32]

G1-79.11

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[27] Carson Draft Title V Permit, pdf 1.
[28] Fox Comments, p. 6.
[29] *Id.*
[30] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir. Dec. 19, 2008).
[31] Fox Comments, pp. 6-7.
[32] *Id.*, p. 7.

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B. The Proposed Permit Contains No Limit on SOx in lb/day or lb/MMSCF for the Vacuum Unit Heater

The proposed permit limit for the vacuum unit heater is 162 ppmv of H_2S in the fuel gas, averaged over three hours and excluding any vent gas from emergency malfunction, process upset or relief valve leakage.[33] Dr. Fox explains that "this concentration limit is equivalent to 4.8 lbs/hr of H_2S. When the fuel is combusted, it converts to SO_2. Thus, the proposed limit on H_2S concentration in the fuel gas is equivalent to an SO_2 emission rate limit of 9.6 lb/hr or 230 lb/day."[34] Yet, the DEIR assumes the daily controlled SO_2 emissions from the vacuum unit heater are 4.94 lbs/day[35] and the net increase in SO_2 from the increased firing rate is 1.80 lbs/day.[36] Thus the proposed permit allows greater emissions from the vacuum unit heater than were analyzed in the DEIR. According to Dr. Fox, when the increase in SO_2 allowed from the vacuum unit heater is combined with other Project SO_2 emission increases and decreases (as reported in DEIR Table 4.2-4), the Project SO_2 emissions are 230 lbs/day.[37] This exceeds the Air District's SO_2 significance threshold of 150 lbs/day.[38] Thus, the proposed Title V permit allows a significant air quality impact not disclosed in the DEIR. G1-79.12

C. Stack Tests are Insufficient to Ensure Compliance with Emission Limits

The draft permit provides that compliance with the emission limits for PM, ROG, NOx and CO would be determined using an annual stack test.[39] Dr. Fox explains that "annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions."[40] Since CEMS are available for NOx, ROG and CO, Dr. Fox recommends that CEMS be required to determine compliance with the proposed NOx, ROG and CO emission limits.[41] Dr. Fox points out that accurately verifying compliance with the NOx and G1-79.13

[33] Carson Draft Title V Permit, pdf 47.
[34] Fox Comments, p. 8.
[35] DEIR, p. B-3-48.
[36] DEIR, Table 4.3-6.
[37] Fox Comments, p. 7.
[38] *Id.*
[39] Carson Draft Title V Permit, Condition D29.X1.
[40] Fox Comments, p. 8.
[41] *Id.*

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ROG limits are particularly important because the Air District "is in serious nonattainment with ozone ambient air quality standards."[42] G1-79.13 cont'd.

D. The Proposed Permit Allows Emissions from the Refinery Flare No. 5 System (Process 21, System 6) that Are Not Evaluated in the DEIR

G1-79.14

The proposed Title V permit adds the Alkylation Unit (Process 9, System 1) to the Refinery No. 5 Flare System.[43] The DEIR does not specifically disclose this addition; it merely mentions that "[p]art of the piping associated with unit modifications may include installation of new pressure relief valves that will tie into the various Refinery flare."[44]

The proposed Title V permit changes the emission limits for this flare system as follows:

- ROG: from 36 lbs/day to 48.7 lbs/day;
- CO: from 21 lbs/day to 243.33 lbs/day; and
- PM: from 106 lbs/day to 52.14 lbs/day.

According to Dr. Fox, the addition of the flare system would also increase NOx and SOx emissions.[45] The proposed permit modifications do not include any limits on NOx or SOx. Further, the DEIR does not include these emission increases.

Dr. Fox provides that the flare system increase in ROG emissions (12.7 lbs/day), when added to other Project increases and decreases in ROG emissions (found in DEIR Table 4.2-4), result in total ROG emissions of 61.8 lbs/day, which exceeds the Air District's ROG significance threshold of 55 lbs/day.[46]

E. The Proposed Permit Fails to Require All Necessary Conditions for the FCCU Shutdown

G1-79.15

The proposed permit requires the shutdown of the FCCU equipment in Condition L341.X1. Dr. Fox points out that the proposed permit fails to include the removal of all supporting fugitive components or, in the alternative, fails to explain

[42] *Id.*
[43] Draft Carson Title V Permit, pdf 45.
[44] DEIR, p. 2-46.
[45] Fox Comments, p. 9.
[46] *Id.*

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how the components would be abandoned in place.[47] Dr. Fox explains that if the components are abandoned in place, the proposed permit must impose conditions that ensure "piping and components are maintained hydrocarbon free, either by blind flanging or by blind flanging and air-gapping."[48] If the permit does not contain these conditions, the DEIR must be revised to eliminate the assumed ROG reductions of 17.6 lbs/day from FCCU fugitive components.[49] If the reductions are eliminated, the total Project VOC emissions would increase to 67 lbs/day, which exceeds the Air District's ROG significance threshold of 55 lbs/day.[50] G1-79.15 cont'd.

IV. CONCLUSION

The Air District cannot issue the proposed Title V permit modifications for the Wilmington and Carson Operations. The proposed modifications for both the Wilmington and Carson Operations are inconsistent with many of the assumptions used in the DEIR to analyze the change in emissions from the Project, allow much higher emission increases of NOx than assumed in the DEIR, and fails to ensure that ambient air quality standards are not exceeded. G1-79.16

Sincerely,

Rachael Koss

Rachael Koss

REK:ric

47 *Id.*, p. 10.
48 *Id.*
49 *Id.*
50 *Id.*

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ATTACHMENT A

Phyllis Fox, Ph.D., PE
745 White Pine Ave.
Rockledge, FL 32955
321-626-6885

June 9, 2016

Rachael Koss
Adams Broadwell Joseph & Cardozo
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South San Francisco, CA 94080-7037

Dear Ms. Koss:

Per your request, I have reviewed the proposed Title V significant permit revisions for Tesoro Refining & Marketing Co. LLC, the Wilmington site (Facility ID #800436) and the Carson site (Facility ID #174655). I reviewed the separate draft Title V permit for each facility. As the draft permits do not have any official page numbers, my citations herein are to the pdf page number in each separate document. Thus, the first page of the draft Wilmington Title V permit is pdf 1, etc. and the first page of the draft Carson Title V permit is also pdf 1, etc.

The proposed modifications are based on changes described in the Draft Environmental Impact Report (DEIR) for the Tesoro Los Angeles Refinery Integration and Compliance Project (Project).[1] The specific modifications covered by this revision to the Title V permits represent only a tiny fraction of the changes described in the DEIR. They cover two heaters, Wilmington DCU heater H-100 and Carson No. 51 vacuum heater; the addition of various non-emitting equipment; modifications to the No. 5 Flare System; the shutdown of the Wilmington FCCU; and various fugitive emission sources. G1-79.17

Based on my review, summarized below, many of the proposed modifications allow much higher emissions than assumed in the DEIR.

[1] Environmental Audit, Inc., Tesoro Los Angeles Refinery Integration and Compliance Project Draft Environmental Impact Report, March 2016; Available at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects.

Relationship to the DEIR

The DEIR evaluated the significance of the Project's operational emissions by calculating the change in daily emissions due to the Project, relative to the CEQA baseline in 2012 to 2013 as follows:[2]

Increase in Emission = Project Emissions (lb/day) – Baseline Emissions (lb/day)

The resulting emission changes for all Project components in pounds per day (lb/day) were compared to the SCAQMD's CEQA significance thresholds. This analysis is summarized in DEIR Table 4.2-4, which concluded that the Project would not result in any significant changes in emissions.

My review of the proposed Title V permit modifications indicates that they fail to assure the emission reductions assumed in the DEIR are achieved in practice and are enforceable.[3] The DEIR deviated from the standard emission increase calculation for heaters that experienced an increase in firing rate. For these heaters, the DEIR used the 98th percentile of the maximum emission rate as the baseline, rather than the daily average emissions in 2012 and 2013. See my DEIR Comment V.C. This artificially inflates the baseline, reducing the emission increases from increases in heater firing rates. The use of an inflated baseline means the emission changes ascribed to the Project are much lower than the actual emission changes that will occur as a result of the Project. The Title V permits must either be modified to assure that the assumed emission reductions are achieved in practice and are enforceable, or the DEIR must be modified to use the correct CEQA baseline and the Title V permit adjusted to ensure they are enforceable. G1-79.18

Wilmington Title V Permit Modifications

<u>DCU H-100 Heater Duty Bump</u>

The draft permit includes new conditions for this heater at: A63.XX (PM10, ROG, CO emission limits), A63.YY (NOx, SOx emission limits), A99.X (NOx emission limit startup and shutdown exemption), A195.XX (NOx rolling 24-hr average), A195.YY (SOx rolling 24-hr average), and D29.X (annual stack tests). The changes to the permit are reportedly based on SCAQMD Application 567439. G1-79.19

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[2] DEIR, Appx. B-3.

[3] DEIR, Appx. B-3 and Table 4.2-4.

Daily Criteria Pollutant Emissions

The Project increases the firing rate of heater H-100 by 20%, from the design heat release basis of 252 MMBtu/hr to the maximum heat release basis of 302.4 MMBtu/hr.[4] Increased firing rate increases emissions in direct proportion to the increase. However, the DEIR concluded that the increased firing rate would reduce emissions of all criteria pollutants except SOx by using the wrong baseline as explained in my comments on the DEIR. The emission reductions for heater H-100 claimed in the DEIR are as follows:[5] G1-79.20

- NOx: -171.03 lb/day
- CO: -5.14 lb/day
- PM10: -0.98 lb/day
- PM2.5: -0.98 lb/day
- VOC: -0.43 lb/day
- SOx: 86.69 lb/day

As explained in my comments on the DEIR, this counterintuitive result was obtained by using the 98th percentile of the maximum emissions for baseline emissions. However, this heater does not operate day in and day out at the 98th percentile value. The Title V permit must impose enforceable emission limits to assure that the reductions assumed in the DEIR are achieved in practice or the DEIR must be revised to correct the heater H-100 emission calculations using the correct CEQA baseline.

Further, the SCAQMD permit application for the subject modification to heater H-100's firing rate asserts that "Tesoro does not propose to increase the potentials to emit for this heater."[6] However, the proposed daily SOx limit of 250 lb/day and the proposed daily ROG limit of 35 lb/day are much higher than the potential to emit for heater H-100. The SOx PTE is 133 lb/day, compared to the proposed limit of 250 lb/day. The ROG PTE is 27 lb/day,[7] compared to the proposed limit of 35 lb/day. The 8 lb/day difference between the proposed ROG limit and the ROG PTE (35-27=8) is sufficient to tip the total Project ROG emissions of 49.09 lb/day over the CEQA significance threshold of 55 lb/day (49+8=57>55).[8] The DEIR, on the other hand, assumes the H-100 duty bump would reduce VOC emissions. Thus, it is evident that G1-79.21

[4] DEIR, pp. 1-11/12.

[5] DEIR, Table 4.2-4.

[6] SCAQMD Application 567439, pdf 14.

[7] SCAQMD Application 567439, pdf 14.

[8] Revised ROG emissions 49.09 – 35 – 27 = 57 lb/day, which is greater than 55 lb/day.

3

the proposed Title V permit limits do not assure that the emission assumptions in the DEIR are achieved. G1-79.21 cont'd.

Hourly NOx and SOx Limits

Condition S11.X sets an hourly limit on NOx of 18.4 lb/hr and an hourly limit on SOx of 14.08 lb/hr. These hourly emission limits are consistent with emissions used in the criteria pollutant air quality modelling for this heater.[9]

However, subsequent conditions in the draft Wilmington Title V permit weaken these hourly limits by specifying an averaging time that allows exceedances of the 1-hour limits to be averaged out. Condition A195.XX stipulates that compliance with the "hourly" NOx limit is based on a rolling 24-hour average. Condition A195.YY stipulates that compliance with the 1-hour SOx limit is also based on a rolling 24-hour average. This type of averaging convention allows much higher hourly emissions than were assumed in the criteria pollutant modelling, performed to demonstrate compliance with ambient air quality standards.[10] G1-79.22

A rolling 24-hour average smooths out emissions data and eliminates peak hourly values that would otherwise exceed the hourly values used in the air dispersion modeling analysis and limited in Condition S11.X. A rolling 24-hour average works like this. You take the first 24 hourly measurements (which may include values that exceed the hourly permit limit by a significant amount) and you average them all together for the first data point. You then drop out the first hourly value and average the next 24 hourly measurements. You continue in this manner, rolling through the entire data set, 24 hours at a time. If any of these 24-hour averages exceeds the hourly averages in Condition S11.X, it's a violation of the limit. This guts the intent of the 1-hour limit in Condition S11.X, which is essential to assure that hourly average ambient air quality standards are not exceeded.

This is particularly critical for NOx. The DEIR reported a total 1-hour average NOx concentration of 301.4 ug/m^3, compared to the State 1-hour ambient air quality standard of 339 ug/m^3.[11] The DEIR also reported a total 1-hour average NOx G1-79.23

[9] The air quality modelling assumed: NOx: 2.7761364 g/s and SOx: 1.9145803 g/s. (Files: I&C - 1-8-hr (incl Cogen)_2011_NOX.dta and I&C - 1-8-hr (incl Cogen) 2011_SOX.dta). These are equivalent to (2.7761364 g/s)(60 s/min)(60 min/hr)(0.00220462 lb/g) = **22.03 lb/hr** for NOx and (1.9145803 g/s)(60 s/min)(60 min/hr)(0.00220462 lb/g) = **15.2 lb/hr** for SOx.

[10] DEIR, Table 4.2-12 and Table 10, p. B-3-23.

[11] DEIR, Table 4.2-12.

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concentration of 184.9 ug/m^3 compared to the federal 1-hour ambient air quality standard of 188 ug/m^3.[12] These values are very close to the standards. If the modelled NOx concentration increased by just 3.2 ug/m^3,[13] from 38.6 ug/m^3 to 41.8 ug/m^3, the total NOx concentration would exceed the federal 1-hour NOx standard. This is readily foreseeable, given the 24-hour rolling averaging time. Thus, the proposed 24-hour averaging times allows potentially significant unmitigated ambient air quality impacts. G1-79.3 cont'd.

The rolling 24-hour averaging convention may also allow violations of the 1-hour SO_2 State (655 ug/m^3) and federal (196 ug/m^3) ambient air quality standards, especially the federal standard.

Therefore, the 24-hour rolling average conventions in Conditions A195XX and A195.YY should be eliminated.

Exceptions to Hourly NOx and SOx Limits

In addition to the generous averaging convention for hourly NOx and SOx limits, Condition A99.X at pdf 19 sets an exception to the new hourly NOx limit as follows:

<u>The 18.40 lb/hr NOX emission limit(s) shall not apply during the heater startup, shutdowns or refractory dryout periods. For the purpose of this exception, each startup event shall not exceed 48 hours, not including refractory dryout period up to 48 additional hours and each shutown event shall not exceed 24 hours.</u> G1-79.24

This exemption would allow unlimited increases in NOx emissions, sufficient to violate the state and federal 1-hour NOx ambient air quality standards and exceed the 55 lb/day NOx CEQA significance threshold for up to 48 hours at a time. A 10-fold increase, for example, is plausible as the SCR system, which typically reduces 90% of the NOx, would be off-line. This would be sufficient to violate the federal and state 1-hour NOx ambient air quality standards and exceed the CEQA NOx significance threshold.

The DEIR did not evaluate the impact of exemptions from hourly NOx limits on ambient air quality. This exemption results in a significant impact that was not disclosed in the DEIR. Further, automatic exemptions from permit limits during G1-79.25

[12] DEIR, Table 10, p. B-3-23.

[13] 1-hr federal NOx NAAQS – total = 188-184.9 = 3.9 ug/m^3. The modeled 1-hour federal impact is 38.6 ug/m3. Thus, a 10% increase in the 1-hour NOx emission rate would exceed the federal 1-hour NOx NAAQS.

startups and shutdowns are no longer allowed.[14] The exemption in Condition A99.X should be eliminated. G1-79.25 cont'd.

Compliance

Compliance with the emission limits for PM10, ROG, and CO is determined using an annual stack test,[15] while compliance with NOx and SOx limits is based on the use of a SCAQMD-certified continuous emission monitoring system (CEMS). Annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions. As CEMS are available for ROG, CO, and PM, they should be required to determine compliance with the proposed ROG, CO, and PM emission limits. It is particularly important to accurately verify compliance with the ROG limit as the SCAQMD is in serious nonattainment with ozone ambient air quality standards. G1-79.26

Carson Title V Permit Modifications

<u>Carson No. 51 (D63) Vacuum Unit Heater</u>

The Carson No. 51 Vacuum Unit Heater (D63) will be modified to increase its maximum permitted firing rate from 276.98 MMBtu/hr (98th percentile)[16] to 360 MMBtu/hr.[17] The increase in firing rate will increase emissions. The draft Title V permit sets new limits at A99.X1 (startup and shutdown exemption), A195.X1 (NOx 24 hr average), B61.8 (fuel gas H_2S limit), C1.X1 (heat input limit), and D29.X1 (test methods). G1-79.27

NOx, ROG, CO, and PM Emission Limits

The draft permit sets the following emission limits:[18]

- CO: 29.6 lb/MMSCF natural gas
- PM: 6.3 lbs/MMSCF natural gas
- ROG: 5.9 lbs/MMSCF natural gas
- NOx: 2.62 lbs/day natural gas

[14] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir., Dec. 19, 2008).

[15] Wilmington Draft Title V Permit, pdf 18, Condition A63.XX.

[16] DEIR, p. B-3-56.

[17] DEIR, p. B-3-49 and Wilmington Draft Title V Permit, Condition C1.X1.

[18] Carson Draft Title V Permit, pdf 1.

Assuming the maximum firing rate of 360 MMBtu/hr and the higher heating value (HHV) of natural gas of 1050 MMBtu/MMSCF[19], these are equivalent to:

- CO: 244 lbs/day (DEIR:247 lbs/day)
- PM: 52 lbs/day (DEIR: 53 lbs/day)
- ROG: 48 lbs/day (DEIR: 50 lbs/day)
- NOx: 2.62 lbs/day (DEIR: 3.93 lbs/day)

These calculations indicate that the limits in lb/MMSCF natural gas are consistent with emissions assumed in the DEIR and the limits in lbs/day in Condition A63.3.[20] G1-79.27 cont'd.

The DEIR calculated the increase in emissions from the increased firing rate relative to the 98th percentile baseline, which is the wrong CEQA baseline. Thus, these limits allow a higher increase in emissions of these pollutants than assumed in the DEIR. However, it appears that the excess is much smaller than in the case of Wilmington heater H-100. These limits should thus be adjusted down to account for reductions relative to the 2012/2013 average CEQA baseline rather than the 98th percentile baseline.

However, Condition A99.X1 at pdf 46 exempts the 2.62 lbs/hr NOx limit during startups and shutdowns and allows the exemption to last up to 48 hours. Condition A195.X1 further specifies that the 2.62 lb/hr limit is based on a 24 hour average.

Thus, as explained for Wilmington heater H-100, the exemption and the 24 hour average allow much higher NOx emissions than assumed in the DEIR. These higher NOx emissions could cause violations of the State and federal 1-hour NOx ambient air quality standards as well as exceed the 55 lb/hr NOx significance threshold. G1-79.28

The DEIR did not evaluate the impact of exemptions from hourly NOx limits on ambient air quality or the impact of using a 24-hour average on compliance with the 1-hour NOx standards. Further, automatic exemptions from permit limits during startups and shutdowns are no longer allowed.[21] The exemption in Condition A99.X1 should be eliminated.

[19] DEIR, Appx. B-3, p. B-3-48.

[20] Carson Draft Title V Permit, pdf 46: ROG <48.67 lb/day; CO <243.33 lbs/day; PM <52.14 lb/day.

[21] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir., Dec. 19, 2008).

SOx Emission Limit

The draft Carson Title V permit does not contain a limit on SOx in lb/day or lb/MMSCF. Rather, it sets a limit of 162 ppmv on H_2S in the fuel gas, averaged over 3 hours and excluding any vent gas from emergency malfunction, process upset or relief valve leakage.[22] This concentration limit is equivalent to 4.8 lb/hr[23] of H_2S. When the fuel gas is combusted, the H_2S is converted into SO_2. Thus, the proposed limit on H_2S concentration in the fuel gas is equivalent to an SO_2 emission rate limit of 9.6 lb/hr or 230 lb/day.

The DEIR, on the other hand, assumed the daily controlled SO_2 emissions from this heater are 4.94 lb/day[24] and the net increase in SO_2 due to the increased firing rate are 1.80 lb/day.[25] Thus, the Carson draft Title V permit fails to limit SO_2 emissions to those assumed in the DEIR. G1-79.29

The increase in SO_2 allowed from this single heater, combined with all other Project SO_2 emission increases and decreases as reported in DEIR Table 4.2-4, is 230 lb/day. This exceeds the SO_2 significance threshold of 150 lb/day.[26] Maximum daily SO_2 emissions could be even higher, as the 160 ppm H_2S limit is exempted under certain upset conditions. Thus, the draft Carson Title V Permit allows a significant air quality impact not disclosed in the DEIR.

Compliance

Compliance with the emission limits for PM, ROG, NOx, and CO is determined using an annual stack test.[27] Annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions. As CEMS are available for NOx, ROG, CO and PM, they should be required to determine compliance with the proposed NOx, ROG, CO, and PM emission limits. It is particularly important to accurately verify compliance with the NOx and ROG limits as the SCAQMD is in serious nonattainment with ozone ambient air quality standards. G1-79.30

[22] Draft Carson Title V Permit, pdf 47.

[23] Converting ppm H_2S to lb/hr H_2S: (160 ppm)(34 lb/lb-mole)(360 MMBtu/hr)(1,000,000 scf/MMsfc)/1050 MMBtu/MMscf]/[386.5 ft^3/lb-lb-mole x 10^6 ppm] = **4.83 lb/hr H_2S .**

[24] DEIR, pdf B-3-48.

[25] DEIR, Table 4.3-6.

[26] Total Project SO_2 emissions = <0.01 + 230 = 230 lb/day.

[27] Carson Draft Title V Permit, pdf 48, Condition D29.X1.

The draft Carson Title V permit does not explain how compliance with the H_2S limit will be determined. In fact, it eliminates Condition D90.16, which required monitoring for H_2S, but fails to replace this condition.

The draft Carson Title V permit should be modified to include a SOx limit consistent with DEIR assumptions and should require compliance using a SCAQMD-certified continuous emission monitoring system (CEMS). G1-79.31

Refinery Flare No. 5 System (Process 21, System 6)

The draft Carson Title V permit adds the Alkylation Unit (Process 9, System 1) to the Refinery No. 5 Flare System.[28] This addition is not specifically disclosed in the DEIR, beyond a general mention that "[p]art of the piping associated with unit modifications may include installation of new pressure relief values that will tie into the various Refinery flare."[29] The emission limits for this flare system are changed as follows:

- ROG: from 36 lb/day to 48.7 lb/day
- CO: from 21 lb/day to 243.33 lb/day
- PM: from 106 lb/day to 52.14 lb/day

G1-79.32

The addition of the Alkylation Unit to the No. 5 Flare System would also increase NOx and SOx emissions, but the proposed permit modifications do not include any limits on NOx or SOx.

These emissions changes are not included in the DEIR. The increase in ROG emissions, 12.7 lb/day, when added to other Project increases and decreases in DEIR Table 4.2-4, results in total ROG emissions of 61.8 lb/day, which exceeds the ROG significance threshold of 55 lb/day. Further, the draft Carson Title V permit fails to set emission limits for this flare system on NOx or SOx or to include any compliance monitoring. The proposed reduction in PM emissions is unsupported and inconsistent with adding the Alkylation Unit to the No. 5 Flare System.

[28] Draft Carson Title V Permit, pdf 45.

[29] DEIR, p. 2-46.

FCCU Shutdown

The draft Carson Title V permit requires the shutdown of FCCU equipment in Condition L341.X1. This equipment list is incomplete. The DEIR also took credit for 17.6 lb/day of ROG emission reductions from FCCU fugitive components.[30]

The draft Carson Title V permit should be modified to require the removal of all supporting fugitive components in this condition or explain how it will be abandoned G1-79.33
in place. If the latter, conditions must be imposed to assure piping and components are maintained hydrocarbon free, either by blind flanging or blind flanging and air-gapping.[31] Otherwise, the ROG reductions assumed in the DEIR should be eliminated. The elimination of these ROG reductions would increase total Project VOC emissions to 67 lb/day (49.09+17.6=66.69), which exceeds the ROG significance threshold of 55 lb/day.

Phyllis Fox, Ph.D., PE

[30] DEIR, Table 4.2-4.

[31] See SCAQMD Application 567649, pdf 512.

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Dr. Fox has over 40 years of experience in the field of environmental engineering, including air pollution control (BACT, BART, MACT, LAER, RACT), greenhouse gas emissions and control, cost effectiveness analyses, water quality and water supply investigations, hydrology, hazardous waste investigations, environmental permitting, nuisance investigations (odor, noise), environmental impact reports, CEQA/NEPA documentation, risk assessments, and litigation support.

EDUCATION

Ph.D. Environmental/Civil Engineering, University of California, Berkeley, 1980.
M.S. Environmental/Civil Engineering, University of California, Berkeley, 1975.
B.S. Physics (with high honors), University of Florida, Gainesville, 1971.

REGISTRATION

Registered Professional Engineer: Arizona (2001-2014: #36701; retired), California (2002-present: CH 6058), Florida (2001-present: #57886), Georgia (2002-2014: #PE027643; retired), Washington (2002-2014; #38692; retired), Wisconsin (2005-2014: #37595-006; retired)
Board Certified Environmental Engineer, American Academy of Environmental Engineers, Certified in Air Pollution Control (DEE #01-20014), 2002-present
Qualified Environmental Professional (QEP), Institute of Professional Environmental Practice (QEP #02-010007), 2001-present

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Environmental Management, Principal, 1981-present
Lawrence Berkeley National Laboratory, Principal Investigator, 1977-1981
University of California, Berkeley, Program Manager, 1976-1977
Bechtel, Inc., Engineer, 1971-1976, 1964-1966

PROFESSIONAL AFFILIATIONS

American Chemical Society (1981-2010)
Phi Beta Kappa (1970-present)
Sigma Pi Sigma (1970-present)

Who's Who Environmental Registry, PH Publishing, Fort Collins, CO, 1992.
Who's Who in the World, Marquis Who's Who, Inc., Chicago, IL, 11th Ed., p. 371, 1993-present.
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National Research Council Committee on Irrigation-Induced Water Quality Problems (Selenium), Subcommittee on Quality Control/Quality Assurance (1985-1990).
National Research Council Committee on Surface Mining and Reclamation, Subcommittee on Oil Shale (1978-80)

REPRESENTATIVE EXPERIENCE

Performed environmental and engineering investigations, as outlined below, for a wide range of industrial and commercial facilities including: petroleum refineries and upgrades thereto; reformulated fuels projects; refinery upgrades to process heavy sour crudes, including tar sands and light sweet crudes from the Eagle Ford and Bakken Formations; petroleum distribution terminals; coal, coke, and ore/mineral export terminals; LNG export, import, and storage terminals; crude-by-rail projects; shale oil plants; crude oil/condensate marine and rail terminals; coal gasification & liquefaction plants; conventional and thermally enhanced oil production; oil and gas production, including hydraulic fracking and acid stimulation treatments; underground storage tanks; pipelines; compressor stations; gasoline stations; landfills; railyards; hazardous waste treatment facilities; nuclear, hydroelectric, geothermal, wood, biomass, waste, tire-derived fuel, gas, oil, coke and coal-fired power plants; transmission lines; airports; hydrogen plants; petroleum coke calcining plants; coke plants; activated carbon manufacturing facilities; asphalt plants; cement plants; incinerators; flares; manufacturing facilities (e.g., semiconductors, electronic assembly, aerospace components, printed circuit boards, amusement park rides); lanthanide processing plants; ammonia plants; nitric acid plants; urea plants; food processing plants; almond hulling facilities; composting facilities; grain processing facilities; grain elevators; ethanol production facilities; soy bean oil extraction plants; biodiesel plants; paint formulation plants; wastewater treatment plants; marine terminals and ports; gas processing plants; steel mills; iron nugget production facilities; pig iron plant, based on blast furnace technology; direct reduced iron plant; acid regeneration facilities; railcar refinishing facility; battery manufacturing plants; pesticide manufacturing and repackaging facilities; pulp and paper mills; olefin plants; methanol plants; ethylene crackers; desalination plants; selective catalytic reduction (SCR) systems; selective noncatalytic reduction (SNCR) systems; halogen acid furnaces; contaminated property redevelopment projects (e.g., Mission Bay, Southern Pacific Railyards, Moscone Center expansion, San Diego Padres Ballpark); residential developments; commercial office parks, campuses, and shopping centers; server farms; transportation plans; and a wide range of mines including sand and gravel, hard rock, limestone, nacholite, coal, molybdenum, gold, zinc, and oil shale.

EXPERT WITNESS/LITIGATION SUPPORT

- For the California Attorney General, assist in determining compliance with probation terms in the matter of People v. Chevron USA.
- For plaintiffs, assist in developing Petitioners' proof brief for National Parks Conservation Association et al v. U.S. EPA, Petition for Review of Final Administrative Action of the U.S. EPA, In the U.S. Court of Appeals for the Third Circuit, Docket No. 14-3147.
- For plaintiffs, expert witness in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1997-2000) at the Cemex cement plant in Lyons, Colorado. Reviewed produced documents, prepared expert and rebuttal reports on PSD applicability based on NOx emission calculations for a collection of changes considered both individually and collectively. Deposed August 2011. *United States v. Cemex, Inc.*, In U.S. District Court for the District of Colorado (Civil Action No. 09-cv-00019-MSK-MEH). Case settled June 13, 2013.
- For plaintiffs, in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1988 – 2000) at James De Young Units 3, 4, and 5. Reviewed produced documents, analyzed CEMS and EIA data, and prepared netting and BACT analyses for NOx, SO2, and PM10 (PSD case). Expert report February 24, 2010 and affidavit February 20, 2010. *Sierra Club v. City of Holland, et al.*, U.S. District Court, Western District of Michigan (Civil Action 1:08-cv-1183). Case settled. Consent Decree 1/19/14.
- For plaintiffs, in civil action alleging failure to obtain MACT permit, expert on potential to emit hydrogen chloride (HCl) from a new coal-fired boiler. Reviewed record, estimated HCl emissions, wrote expert report June 2010 and March 2013 (Cost to Install a Scrubber at the Lamar Repowering Project Pursuant to Case-by-Case MACT), deposed August 2010 and March 2013. *Wildearth Guardian et al. v. Lamar Utilities Board*, Civil Action No. 09-cv-02974, U.S. District Court, District of Colorado. Case settled August 2013.
- For plaintiffs, expert witness on permitting, emission calculations, and wastewater treatment for coal-to-gasoline plant. Reviewed produced documents. Assisted in preparation of comments on draft minor source permit. Wrote two affidavits on key issues in case. Presented direct and rebuttal testimony 10/27 - 10/28/10 on permit enforceability and failure to properly calculate potential to emit, including underestimate of flaring emissions and

omission of VOC and CO emissions from wastewater treatment, cooling tower, tank roof landings, and malfunctions. *Sierra Club, Ohio Valley Environmental Coalition, Coal River Mountain Watch, West Virginia Highlands Conservancy v. John Benedict, Director, Division of Air Quality, West Virginia Department of Environmental Protection and TransGas Development System, LLC*, Appeal No. 10-01-AQB. Virginia Air Quality Board remanded the permit on March 28, 2011 ordering reconsideration of potential to emit calculations, including: (1) support for assumed flare efficiency; (2) inclusion of startup, shutdown and malfunction emissions; and (3) inclusion of wastewater treatment emissions in potential to emit calculations.

- For plaintiffs, expert on BACT emission limits for gas-fired combined cycle power plant. Prepared declaration in support of CBE's Opposition to the United States' Motion for Entry of Proposed Amended Consent Decree. Assisted in settlement discussions. *U.S. EPA, Plaintiff, Communities for a Better Environment, Intervenor Plaintiff, v. Pacific Gas & Electric Company, et al.*, U.S. District Court, Northern District of California, San Francisco Division. Case No. C-09-4503 SI.
- Technical expert in confidential settlement discussions with large coal-fired utility on BACT control technology and emission limits for NOx, SO2, PM, PM2.5, and CO for new natural gas fired combined cycle and simple cycle turbines with oil backup. (July 2010). Case settled.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1998-99) at Gallagher Units 1 and 3. Reviewed produced documents, prepared expert and rebuttal reports on historic and current-day BACT for SO2, control costs, and excess emissions of SO2. Deposed 11/18/09. *United States et al. v. Cinergy, et al.*. In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Settled 12/22/09.
- For plaintiffs, expert witness on MACT, BACT for NOx, and enforceability in an administrative appeal of draft state air permit issued for four 300-MW pet-coke-fired CFBs. Reviewed produced documents and prepared prefiled testimony. Deposed 10/8/09 and 11/9/09. Testified 11/10/09. *Application of Las Brisas Energy Center, LLC for State Air Quality Permit*; before the State Office of Administrative Hearings, Texas. Permit remanded 3/29/10 as LBEC failed to meet burden of proof on a number of issues including MACT. Texas Court of Appeals dismissed an appeal to reinstate the permit. The Texas Commission on Environmental Quality and Las Brisas Energy Center, LLC sought to overturn the Court of Appeals decision but moved to have their appeal dismissed in August 2013.
- For defense, expert witness in unlawful detainer case involving a gasoline station, minimart, and residential property with contamination from leaking underground storage tanks. Reviewed agency files and inspected site. Presented expert testimony on July 6, 2009, on

causes of, nature and extent of subsurface contamination. *A. Singh v. S. Assaedi*, in Contra Costa County Superior Court, CA. Settled August 2009.

- For plaintiffs, expert witness on netting and enforceability for refinery being upgraded to process tar sands crude. Reviewed produced documents. Prepared expert and rebuttal reports addressing use of emission factors for baseline, omitted sources including coker, flares, tank landings and cleaning, and enforceability. Deposed. *In the Matter of Objection to the Issuance of Significant Source Modification Permit No. 089-25484-00453 to BP Products North America Inc., Whiting Business Unit, Save the Dunes Council, Inc., Sierra Club., Inc., Hoosier Environmental Council et al., Petitioners, B. P. Products North American, Respondents/Permittee,* before the Indiana Office of Environmental Adjudication.
- For plaintiffs, expert witness on BACT, MACT, and enforceability in appeal of Title V permit issued to 600 MW coal-fired power plant burning Powder River Basin coal. Prepared technical comments on draft air permit. Reviewed record on appeal, drafted BACT, MACT, and enforceability pre-filed testimony. Drafted MACT and enforceability pre-filed rebuttal testimony. Deposed March 24, 2009. Testified June 10, 2009. *In Re: Southwestern Electric Power Company*. Arkansas Pollution Control and Ecology Commission, Consolidated Docket No. 08-006-P. Recommended Decision issued December 9, 2009 upholding issued permit. Commission adopted Recommended Decision January 22, 2010.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1989-1992) at Wabash Units 2, 3 and 5. Reviewed produced documents, prepared expert and rebuttal report on historic and current-day BACT for NOx and SO2, control costs, and excess emissions of NOx, SO2, and mercury. Deposed 10/21/08. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Testified 2/3/09. Memorandum Opinion & Order 5-29-09 requiring shutdown of Wabash River Units 2, 3, 5 by September 30, 2009, run at baseline until shutdown, and permanently surrender SO2 emission allowances.
- For plaintiffs, expert witness in liability phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for three historic modifications (1997-2001) at two portland cement plants involving three cement kilns. Reviewed produced documents, analyzed CEMS data covering subject period, prepared netting analysis for NOx, SO_2 and CO, and prepared expert and rebuttal reports. *United States v. Cemex California Cement*, In U.S. District Court for the Central District of California, Eastern Division, Case No. ED CV 07-00223-GW (JCRx). Settled 1/15/09.
- For intervenors Clean Wisconsin and Citizens Utility Board, prepared data requests, reviewed discovery and expert report. Prepared prefiled direct, rebuttal and surrebuttal testimony on cost to extend life of existing Oak Creek Units 5-8 and cost to address future regulatory requirements to determine whether to control or shutdown one or more of the units. Oral testimony 2/5/08. Application for a Certificate of Authority to Install Wet Flue

Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment for Control of Sulfur Dioxide and Nitrogen Oxide Emissions at Oak Creek Power Plant Units 5, 6, 7 and 8, WPSC Docket No. 6630-CE-299.

- For plaintiffs, expert witness on alternatives analysis and BACT for NOx, SO2, total PM10, and sulfuric acid mist in appeal of PSD permit issued to 1200 MW coal fired power plant burning Powder River Basin and/or Central Appalachian coal (Longleaf). Assisted in drafting technical comments on NOx on draft permit. Prepared expert disclosure. Presented 8+ days of direct and rebuttal expert testimony. Attended all 21 days of evidentiary hearing from 9/5/07 – 10/30/07 assisting in all aspects of hearing. *Friends of the Chatahooche and Sierra Club v. Dr. Carol Couch, Director, Environmental Protection Division of Natural Resources Department, Respondent, and Longleaf Energy Associates, Intervener*. ALJ Final Decision 1/11/08 denying petition. ALJ Order vacated & remanded for further proceedings, Fulton County Superior Court, 6/30/08. Court of Appeals of GA remanded the case with directions that the ALJ's final decision be vacated to consider the evidence under the correct standard of review, July 9, 2009. The ALJ issued an opinion April 2, 2010 in favor of the applicant. Final permit issued April 2010.
- For plaintiffs, expert witness on diesel exhaust in inverse condemnation case in which Port expanded maritime operations into residential neighborhoods, subjecting plaintiffs to noise, light, and diesel fumes. Measured real-time diesel particulate concentrations from marine vessels and tug boats on plaintiffs' property. Reviewed documents, depositions, DVDs, and photographs provided by counsel. Deposed. Testified October 24, 2006. *Ann Chargin, Richard Hackett, Carolyn Hackett, et al. v. Stockton Port District*, Superior Court of California, County of San Joaquin, Stockton Branch, No. CV021015. Judge ruled for plaintiffs.
- For plaintiffs, expert witness on NOx emissions and BACT in case alleging failure to obtain necessary permits and install controls on gas-fired combined-cycle turbines. Prepared and reviewed (applicant analyses) of NOx emissions, BACT analyses (water injection, SCR, ultra low NOx burners), and cost-effectiveness analyses based on site visit, plant operating records, stack tests, CEMS data, and turbine and catalyst vendor design information. Participated in negotiations to scope out consent order. *United States v. Nevada Power*. Case settled June 2007, resulting in installation of dry low NOx burners (5 ppm NOx averaged over 1 hr) on four units and a separate solar array at a local business.
- For plaintiffs, expert witness in appeal of PSD permit issued to 850 MW coal fired boiler burning Powder River Basin coal (Iatan Unit 2) on BACT for particulate matter, sulfuric acid mist and opacity and emission calculations for alleged historic violations of PSD. Assisted in drafting technical comments, petition for review, discovery requests, and responses to discovery requests. Reviewed produced documents. Prepared expert report on BACT for particulate matter. Assisted with expert depositions. Deposed February 7, 8, 27, 28, 2007. *In Re PSD Construction Permit Issued to Great Plains Energy, Kansas City Power & Light – Iatan Generating Station, Sierra Club v. Missouri Department of Natural Resources, Great*

Plains Energy, and Kansas City Power & Light. Case settled March 27, 2007, providing offsets for over 6 million ton/yr of CO2 and lower NOx and SO_2 emission limits.

- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications of coal-fired boilers and associated equipment. Reviewed produced documents, prepared expert report on cost to retrofit 24 coal-fired power plants with scrubbers designed to remove 99% of the sulfur dioxide from flue gases. Prepared supplemental and expert report on cost estimates and BACT for SO2 for these 24 complaint units. Deposed 1/30/07 and 3/14/07. *United States and State of New York et al. v. American Electric Power*, In U.S. District Court for the Southern District of Ohio, Eastern Division, Consolidated Civil Action Nos. C2-99-1182 and C2-99-1250. Settlement announced 10/9/07.
- For plaintiffs, expert witness on BACT, enforceability, and alternatives analysis in appeal of PSD permit issued for a 270-MW pulverized coal fired boiler burning Powder River Basin coal (City Utilities Springfield Unit 2). Reviewed permitting file and assisted counsel draft petition and prepare and respond to interrogatories and document requests. Reviewed interrogatory responses and produced documents. Assisted with expert depositions. Deposed August 2005. Evidentiary hearings October 2005. *In the Matter of Linda Chipperfield and Sierra Club v. Missouri Department of Natural Resources.* Missouri Supreme Court denied review of adverse lower court rulings August 2007.
- For plaintiffs, expert witness in civil action relating to plume touchdowns at AEP's Gavin coal-fired power plant. Assisted counsel draft interrogatories and document requests. Reviewed responses to interrogatories and produced documents. Prepared expert report "Releases of Sulfuric Acid Mist from the Gavin Power Station." The report evaluates sulfuric acid mist releases to determine if AEP complied with the requirements of CERCLA Section 103(a) and EPCRA Section 304. This report also discusses the formation, chemistry, release characteristics, and abatement of sulfuric acid mist in support of the claim that these releases present an imminent and substantial endangerment to public health under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"). *Citizens Against Pollution v. Ohio Power Company*, In the U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action No. 2-04-cv-371. Case settled 12-8-06.
- For petitioners, expert witness in contested case hearing on BACT, enforceability, and emission estimates for an air permit issued to a 500-MW supercritical Power River Basin coal-fired boiler (Weston Unit 4). Assisted counsel prepare comments on draft air permit and respond to and draft discovery. Reviewed produced file, deposed (7/05), and prepared expert report on BACT and enforceability. Evidentiary hearings September 2005. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin*, Case No. IH-04-21. The Final Order, issued 2/10/06, lowered the NOx BACT limit from 0.07 lb/MMBtu to 0.06

lb/MMBtu based on a 30-day average, added a BACT SO2 control efficiency, and required a 0.0005% high efficiency drift eliminator as BACT for the cooling tower. The modified permit, including these provisions, was issued 3/28/07. Additional appeals in progress.

- For plaintiffs, adviser on technical issues related to Citizen Suit against U.S. EPA regarding failure to update New Source Performance Standards for petroleum refineries, 40 CFR 60, Subparts J, VV, and GGG. *Our Children's Earth Foundation and Sierra Club v. U.S. EPA et al.* Case settled July 2005. CD No. C 05-00094 CW, U.S. District Court, Northern District of California – Oakland Division. Proposed revisions to standards of performance for petroleum refineries published 72 FR 27178 (5/14/07).
- For interveners, reviewed proposed Consent Decree settling Clean Air Act violations due to historic modifications of boilers and associated equipment at two coal-fired power plants. In response to stay order, reviewed the record, selected one representative activity at each of seven generating units, and analyzed to identify CAA violations. Identified NSPS and NSR violations for NOx, SO_2, PM/PM10, and sulfuric acid mist. Summarized results in an expert report. *United States of America, and Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, Plaintiffs, and Clean Wisconsin, Sierra Club, and Citizens' Utility Board, Intervenors, v. Wisconsin Electric Power Company, Defendant.* U.S. District Court for the Eastern District of Wisconsin, Civil Action No. 2:03-CV-00371-CNC. Order issued 10-1-07 denying petition.
- For a coalition of Nevada labor organizations (ACE), reviewed preliminary determination to issue a Class I Air Quality Operating Permit to Construct and supporting files for a 250-MW pulverized coal-fired boiler (Newmont). Prepared about 100 pages of technical analyses and comments on BACT, MACT, emission calculations, and enforceability. Assisted counsel draft petition and reply brief appealing PSD permit to U.S. EPA Environmental Appeals Board (EAB). Order denying review issued 12/21/05. *In re Newmont Nevada Energy Investment, LLC, TS Power Plant.* PSD Appeal No. 05-04 (EAB 2005).
- For petitioners and plaintiffs, reviewed and prepared comments on air quality and hazardous waste based on negative declaration for refinery ultra low sulfur diesel project located in SCAQMD. Reviewed responses to comments and prepared responses. Prepared declaration and presented oral testimony before SCAQMD Hearing Board on exempt sources (cooling towers) and calculation of potential to emit under NSR. Petition for writ of mandate filed March 2005. Case remanded by Court of Appeals to trial court to direct SCAQMD to re-evaluate the potential environmental significance of NOx emissions resulting from the project in accordance with court's opinion. California Court of Appeals, Second Appellate Division, on December 18, 2007, affirmed in part (as to baseline) and denied in part. *Communities for a Better Environment v. South Coast Air Quality Management District and ConocoPhillips and Carlos Valdez et al v. South Coast Air Quality Management District and ConocoPhillips.* Certified for partial publication 1/16/08. Appellate Court opinion upheld by CA Supreme Court 3/15/10. *(2010) 48 Cal.4th 310.*

- For amici seeking to amend a proposed Consent Decree to settle alleged NSR violations at Chevron refineries, reviewed proposed settlement, related files, subject modifications, and emission calculations. Prepared declaration on emission reductions, identification of NSR and NSPS violations, and BACT/LAER for FCCUs, heaters and boilers, flares, and sulfur recovery plants. *U.S. et al. v. Chevron U.S.A.*, Northern District of California, Case No. C 03-04650. Memorandum and Order Entering Consent Decree issued June 2005. Case No. C 03-4650 CRB.
- For petitioners, prepared declaration on enforceability of periodic monitoring requirements, in response to EPA's revised interpretation of 40 CFR 70.6(c)(1). This revision limited additional monitoring required in Title V permits. 69 FR 3203 (Jan. 22, 2004). *Environmental Integrity Project et al. v. EPA* (U.S. Court of Appeals for the District of Columbia). Court ruled the Act requires all Title V permits to contain monitoring requirements to assure compliance. *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008).
- For interveners in application for authority to construct a 500 MW supercritical coal-fired generating unit before the Wisconsin Public Service Commission, prepared pre-filed written direct and rebuttal testimony with oral cross examination and rebuttal on BACT and MACT (Weston 4). Prepared written comments on BACT, MACT, and enforceability on draft air permit for same facility.
- For property owners in Nevada, evaluated the environmental impacts of a 1,450-MW coal-fired power plant proposed in a rural area adjacent to the Black Rock Desert and Granite Range, including emission calculations, air quality modeling, comments on proposed use permit to collect preconstruction monitoring data, and coordination with agencies and other interested parties. Project cancelled.
- For environmental organizations, reviewed draft PSD permit for a 600-MW coal-fired power plant in West Virginia (Longview). Prepared comments on permit enforceability; coal washing; BACT for SO_2 and PM10; Hg MACT; and MACT for HCl, HF, non-Hg metallic HAPs, and enforceability. Assist plaintiffs draft petition appealing air permit. Retained as expert to develop testimony on MACT, BACT, offsets, enforceability. Participate in settlement discussions. Case settled July 2004.
- For petitioners, reviewed record produced in discovery and prepared affidavit on emissions of carbon monoxide and volatile organic compounds during startup of GE 7FA combustion turbines to successfully establish plaintiff standing. *Sierra Club et al. v. Georgia Power Company* (Northern District of Georgia).
- For building trades, reviewed air quality permitting action for 1500-MW coal-fired power plant before the Kentucky Department for Environmental Protection (Thoroughbred).
- For petitioners, expert witness in administrative appeal of the PSD/Title V permit issued to a 1500-MW coal-fired power plant. Reviewed over 60,000 pages of produced documents, prepared discovery index, identified and assembled plaintiff exhibits. Deposed. Assisted

counsel in drafting discovery requests, with over 30 depositions, witness cross examination, and brief drafting. Presented over 20 days of direct testimony, rebuttal and sur-rebuttal, with cross examination on BACT for NOx, SO_2, and PM/PM10; MACT for Hg and non-Hg metallic HAPs; emission estimates for purposes of Class I and II air modeling; risk assessment; and enforceability of permit limits. Evidentiary hearings from November 2003 to June 2004. *Sierra Club et al. v. Natural Resources & Environmental Protection Cabinet, Division of Air Quality and Thoroughbred Generating Company et al.* Hearing Officer Decision issued August 9, 2005 finding in favor of plaintiffs on counts as to risk, BACT (IGCC/CFB, NOx, SO_2, Hg, Be), single source, enforceability, and errors and omissions. Assist counsel draft exceptions. Cabinet Secretary issued Order April 11, 2006 denying Hearing Offer's report, except as to NOx BACT, Hg, 99% SO2 control and certain errors and omissions.

- For citizens group in Massachusetts, reviewed, commented on, and participated in permitting of pollution control retrofits of coal-fired power plant (Salem Harbor).
- Assisted citizens group and labor union challenge issuance of conditional use permit for a 317,000 ft^2 discount store in Honolulu without any environmental review. In support of a motion for preliminary injunction, prepared 7-page declaration addressing public health impacts of diesel exhaust from vehicles serving the Project. In preparation for trial, prepared 20-page preliminary expert report summarizing results of diesel exhaust and noise measurements at two big box retail stores in Honolulu, estimated diesel PM10 concentrations for Project using ISCST, prepared a cancer health risk assessment based on these analyses, and evaluated noise impacts.
- Assisted environmental organizations to challenge the DOE Finding of No Significant Impact (FONSI) for the Baja California Power and Sempra Energy Resources Cross-Border Transmissions Lines in the U.S. and four associated power plants located in Mexico (DOE EA-1391). Prepared 20-page declaration in support of motion for summary judgment addressing emissions, including CO_2 and NH_3, offsets, BACT, cumulative air quality impacts, alternative cooling systems, and water use and water quality impacts. Plaintiff's motion for summary judgment granted in part. U.S. District Court, Southern District decision concluded that the Environmental Assessment and FONSI violated NEPA and the APA due to their inadequate analysis of the potential controversy surrounding the project, water impacts, impacts from NH_3 and CO_2, alternatives, and cumulative impacts. *Border Power Plant Working Group v. Department of Energy and Bureau of Land Management*, Case No. 02-CV-513-IEG (POR) (May 2, 2003).
- For Sacramento school, reviewed draft air permit issued for diesel generator located across from playfield. Prepared comments on emission estimates, enforceability, BACT, and health impacts of diesel exhaust. Case settled. BUG trap installed on the diesel generator.
- Assisted unions in appeal of Title V permit issued by BAAQMD to carbon plant that manufactured coke. Reviewed District files, identified historic modifications that should have triggered PSD review, and prepared technical comments on Title V permit. Reviewed

responses to comments and assisted counsel draft appeal to BAAQMD hearing board, opening brief, motion to strike, and rebuttal brief. Case settled.

- Assisted California Central Coast city obtain controls on a proposed new city that would straddle the Ventura-Los Angeles County boundary. Reviewed several environmental impact reports, prepared an air quality analysis, a diesel exhaust health risk assessment, and detailed review comments. Governor intervened and State dedicated the land for conservation purposes April 2004.
- Assisted Central California city to obtain controls on large alluvial sand quarry and asphalt plant proposing a modernization. Prepared comments on Negative Declaration on air quality, public health, noise, and traffic. Evaluated process flow diagrams and engineering reports to determine whether proposed changes increased plant capacity or substantially modified plant operations. Prepared comments on application for categorical exemption from CEQA. Presented testimony to County Board of Supervisors. Developed controls to mitigate impacts. Assisted counsel draft Petition for Writ. Case settled June 2002. Substantial improvements in plant operations were obtained including cap on throughput, dust control measures, asphalt plant loadout enclosure, and restrictions on truck routes.
- Assisted oil companies on the California Central Coast in defending class action citizen's lawsuit alleging health effects due to emissions from gas processing plant and leaking underground storage tanks. Reviewed regulatory and other files and advised counsel on merits of case. Case settled November 2001.
- Assisted oil company on the California Central Coast in defending property damage claims arising out of a historic oil spill. Reviewed site investigation reports, pump tests, leachability studies, and health risk assessments, participated in design of additional site characterization studies to assess health impacts, and advised counsel on merits of case. Prepare health risk assessment.
- Assisted unions in appeal of Initial Study/Negative Declaration ("IS/ND") for an MTBE phaseout project at a Bay Area refinery. Reviewed IS/ND and supporting agency permitting files and prepared technical comments on air quality, groundwater, and public health impacts. Reviewed responses to comments and final IS/ND and ATC permits and assisted counsel to draft petitions and briefs appealing decision to Air District Hearing Board. Presented sworn direct and rebuttal testimony with cross examination on groundwater impacts of ethanol spills on hydrocarbon contamination at refinery. Hearing Board ruled 5 to 0 in favor of appellants, remanding ATC to district to prepare an EIR.
- Assisted Florida cities in challenging the use of diesel and proposed BACT determinations in prevention of significant deterioration (PSD) permits issued to two 510-MW simple cycle peaking electric generating facilities and one 1,080-MW simple cycle/combined cycle facility. Reviewed permit applications, draft permits, and FDEP engineering evaluations, assisted counsel in drafting petitions and responding to discovery. Participated in settlement discussions. Cases settled or applications withdrawn.

- Assisted large California city in federal lawsuit alleging peaker power plant was violating its federal permit. Reviewed permit file and applicant's engineering and cost feasibility study to reduce emissions through retrofit controls. Advised counsel on feasible and cost-effective NOx, SOx, and PM10 controls for several 1960s diesel-fired Pratt and Whitney peaker turbines. Case settled.
- Assisted coalition of Georgia environmental groups in evaluating BACT determinations and permit conditions in PSD permits issued to several large natural gas-fired simple cycle and combined-cycle power plants. Prepared technical comments on draft PSD permits on BACT, enforceability of limits, and toxic emissions. Reviewed responses to comments, advised counsel on merits of cases, participated in settlement discussions, presented oral and written testimony in adjudicatory hearings, and provided technical assistance as required. Cases settled or won at trial.
- Assisted construction unions in review of air quality permitting actions before the Indiana Department of Environmental Management ("IDEM") for several natural gas-fired simple cycle peaker and combined cycle power plants.
- Assisted coalition of towns and environmental groups in challenging air permits issued to 523 MW dual fuel (natural gas and distillate) combined-cycle power plant in Connecticut. Prepared technical comments on draft permits and 60 pages of written testimony addressing emission estimates, startup/shutdown issues, BACT/LAER analyses, and toxic air emissions. Presented testimony in adjudicatory administrative hearings before the Connecticut Department of Environmental Protection in June 2001 and December 2001.
- Assisted various coalitions of unions, citizens groups, cities, public agencies, and developers in licensing and permitting of over 110 coal, gas, oil, biomass, and pet coke-fired power plants generating over 75,000 MW of electricity. These included base-load, combined cycle, simple cycle, and peaker power plants in Alaska, Arizona, Arkansas, California, Colorado, Georgia, Florida, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Oklahoma, Oregon, Texas, West Virginia, Wisconsin, and elsewhere. Prepared analyses of and comments on applications for certification, preliminary and final staff assessments, and various air, water, wastewater, and solid waste permits issued by local agencies. Presented written and oral testimony before various administrative bodies on hazards of ammonia use and transportation, health effects of air emissions, contaminated property issues, BACT/LAER issues related to SCR and SCONOx, criteria and toxic pollutant emission estimates, MACT analyses, air quality modeling, water supply and water quality issues, and methods to reduce water use, including dry cooling, parallel dry-wet cooling, hybrid cooling, and zero liquid discharge systems.
- Assisted unions, cities, and neighborhood associations in challenging an EIR issued for the proposed expansion of the Oakland Airport. Reviewed two draft EIRs and prepared a health risk assessment and extensive technical comments on air quality and public health impacts. The California Court of Appeals, First Appellate District, ruled in favor of appellants and

plaintiffs, concluding that the EIR "2) erred in using outdated information in assessing the emission of toxic air contaminants (TACs) from jet aircraft; 3) failed to support its decision not to evaluate the health risks associated with the emission of TACs with meaningful analysis," thus accepting my technical arguments and requiring the Port to prepare a new EIR. See *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598.

- Assisted lessor of former gas station with leaking underground storage tanks and TCE contamination from adjacent property. Lessor held option to purchase, which was forfeited based on misrepresentation by remediation contractor as to nature and extent of contamination. Remediation contractor purchased property. Reviewed regulatory agency files and advised counsel on merits of case. Case not filed.
- Advised counsel on merits of several pending actions, including a Proposition 65 case involving groundwater contamination at an explosives manufacturing firm and two former gas stations with leaking underground storage tanks.
- Assisted defendant foundry in Oakland in a lawsuit brought by neighbors alleging property contamination, nuisance, trespass, smoke, and health effects from foundry operation. Inspected and sampled plaintiff's property. Advised counsel on merits of case. Case settled.
- Assisted business owner facing eminent domain eviction. Prepared technical comments on a negative declaration for soil contamination and public health risks from air emissions from a proposed redevelopment project in San Francisco in support of a CEQA lawsuit. Case settled.
- Assisted neighborhood association representing residents living downwind of a Berkeley asphalt plant in separate nuisance and CEQA lawsuits. Prepared technical comments on air quality, odor, and noise impacts, presented testimony at commission and council meetings, participated in community workshops, and participated in settlement discussions. Cases settled. Asphalt plant was upgraded to include air emission and noise controls, including vapor collection system at truck loading station, enclosures for noisy equipment, and improved housekeeping.
- Assisted a Fortune 500 residential home builder in claims alleging health effects from faulty installation of gas appliances. Conducted indoor air quality study, advised counsel on merits of case, and participated in discussions with plaintiffs. Case settled.
- Assisted property owners in Silicon Valley in lawsuit to recover remediation costs from insurer for large TCE plume originating from a manufacturing facility. Conducted investigations to demonstrate sudden and accidental release of TCE, including groundwater modeling, development of method to date spill, preparation of chemical inventory, investigation of historical waste disposal practices and standards, and on-site sewer and storm drainage inspections and sampling. Prepared declaration in opposition to motion for summary judgment. Case settled.

- Assisted residents in east Oakland downwind of a former battery plant in class action lawsuit alleging property contamination from lead emissions. Conducted historical research and dry deposition modeling that substantiated claim. Participated in mediation at JAMS. Case settled.
- Assisted property owners in West Oakland who purchased a former gas station that had leaking underground storage tanks and groundwater contamination. Reviewed agency files and advised counsel on merits of case. Prepared declaration in opposition to summary judgment. Prepared cost estimate to remediate site. Participated in settlement discussions. Case settled.
- Consultant to counsel representing plaintiffs in two Clean Water Act lawsuits involving selenium discharges into San Francisco Bay from refineries. Reviewed files and advised counsel on merits of case. Prepared interrogatory and discovery questions, assisted in deposing opposing experts, and reviewed and interpreted treatability and other technical studies. Judge ruled in favor of plaintiffs.
- Assisted oil company in a complaint filed by a resident of a small California beach community alleging that discharges of tank farm rinse water into the sanitary sewer system caused hydrogen sulfide gas to infiltrate residence, sending occupants to hospital. Inspected accident site, interviewed parties to the event, and reviewed extensive agency files related to incident. Used chemical analysis, field simulations, mass balance calculations, sewer hydraulic simulations with SWMM44, atmospheric dispersion modeling with SCREEN3, odor analyses, and risk assessment calculations to demonstrate that the incident was caused by a faulty drain trap and inadequate slope of sewer lateral on resident's property. Prepared a detailed technical report summarizing these studies. Case settled.
- Assisted large West Coast city in suit alleging that leaking underground storage tanks on city property had damaged the waterproofing on downgradient building, causing leaks in an underground parking structure. Reviewed subsurface hydrogeologic investigations and evaluated studies conducted by others documenting leakage from underground diesel and gasoline tanks. Inspected, tested, and evaluated waterproofing on subsurface parking structure. Waterproofing was substandard. Case settled.
- Assisted residents downwind of gravel mine and asphalt plant in Siskiyou County, California, in suit to obtain CEQA review of air permitting action. Prepared two declarations analyzing air quality and public health impacts. Judge ruled in favor of plaintiffs, closing mine and asphalt plant.
- Assisted defendant oil company on the California Central Coast in class action lawsuit alleging property damage and health effects from subsurface petroleum contamination. Reviewed documents, prepared risk calculations, and advised counsel on merits of case. Participated in settlement discussions. Case settled.

- Assisted defendant oil company in class action lawsuit alleging health impacts from remediation of petroleum contaminated site on California Central Coast. Reviewed documents, designed and conducted monitoring program, and participated in settlement discussions. Case settled.
- Consultant to attorneys representing irrigation districts and municipal water districts to evaluate a potential challenge of USFWS actions under CVPIA section 3406(b)(2). Reviewed agency files and collected and analyzed hydrology, water quality, and fishery data. Advised counsel on merits of case. Case not filed.
- Assisted residents downwind of a Carson refinery in class action lawsuit involving soil and groundwater contamination, nuisance, property damage, and health effects from air emissions. Reviewed files and provided advise on contaminated soil and groundwater, toxic emissions, and health risks. Prepared declaration on refinery fugitive emissions. Prepared deposition questions and reviewed deposition transcripts on air quality, soil contamination, odors, and health impacts. Case settled.
- Assisted residents downwind of a Contra Costa refinery who were affected by an accidental release of naphtha. Characterized spilled naphtha, estimated emissions, and modeled ambient concentrations of hydrocarbons and sulfur compounds. Deposed. Presented testimony in binding arbitration at JAMS. Judge found in favor of plaintiffs.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects from several large accidents as well as routine operations. Reviewed files and prepared analyses of environmental impacts. Prepared declarations, deposed, and presented testimony before jury in one trial and judge in second. Case settled.
- Assisted business owner claiming damages from dust, noise, and vibration during a sewer construction project in San Francisco. Reviewed agency files and PM10 monitoring data and advised counsel on merits of case. Case settled.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects. Prepared declaration in opposition to summary judgment, deposed, and presented expert testimony on accidental releases, odor, and nuisance before jury. Case thrown out by judge, but reversed on appeal and not retried.
- Presented testimony in small claims court on behalf of residents claiming health effects from hydrogen sulfide from flaring emissions triggered by a power outage at a Contra Costa County refinery. Analyzed meteorological and air quality data and evaluated potential health risks of exposure to low concentrations of hydrogen sulfide. Judge awarded damages to plaintiffs.
- Assisted construction unions in challenging PSD permit for an Indiana steel mill. Prepared technical comments on draft PSD permit, drafted 70-page appeal of agency permit action to

the Environmental Appeals Board challenging permit based on faulty BACT analysis for electric arc furnace and reheat furnace and faulty permit conditions, among others, and drafted briefs responding to four parties. EPA Region V and the EPA General Counsel intervened as amici, supporting petitioners. EAB ruled in favor of petitioners, remanding permit to IDEM on three key issues, including BACT for the reheat furnace and lead emissions from the EAF. Drafted motion to reconsider three issues. Prepared 69 pages of technical comments on revised draft PSD permit. Drafted second EAB appeal addressing lead emissions from the EAF and BACT for reheat furnace based on European experience with SCR/SNCR. Case settled. Permit was substantially improved. See *In re: Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5 (EAB June 22, 2000).

- Assisted defendant urea manufacturer in Alaska in negotiations with USEPA to seek relief from penalties for alleged violations of the Clean Air Act. Reviewed and evaluated regulatory files and monitoring data, prepared technical analysis demonstrating that permit limits were not violated, and participated in negotiations with EPA to dismiss action. Fines were substantially reduced and case closed.
- Assisted construction unions in challenging PSD permitting action for an Indiana grain mill. Prepared technical comments on draft PSD permit and assisted counsel draft appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analyses for heaters and boilers and faulty permit conditions, among others. Case settled.
- As part of a consent decree settling a CEQA lawsuit, assisted neighbors of a large west coast port in negotiations with port authority to secure mitigation for air quality impacts. Prepared technical comments on mobile source air quality impacts and mitigation and negotiated a $9 million CEQA mitigation package. Represented neighbors on technical advisory committee established by port to implement the air quality mitigation program. Program successfully implemented.
- Assisted construction unions in challenging permitting action for a California hazardous waste incinerator. Prepared technical comments on draft permit, assisted counsel prepare appeal of EPA permit to the Environmental Appeals Board. Participated in settlement discussions on technical issues with applicant and EPA Region 9. Case settled.
- Assisted environmental group in challenging DTSC Negative Declaration on a hazardous waste treatment facility. Prepared technical comments on risk of upset, water, and health risks. Writ of mandamus issued.
- Assisted several neighborhood associations and cities impacted by quarries, asphalt plants, and cement plants in Alameda, Shasta, Sonoma, and Mendocino counties in obtaining mitigations for dust, air quality, public health, traffic, and noise impacts from facility operations and proposed expansions.

- For over 100 industrial facilities, commercial/campus, and redevelopment projects, developed the record in preparation for CEQA and NEPA lawsuits. Prepared technical comments on hazardous materials, solid wastes, public utilities, noise, worker safety, air quality, public health, water resources, water quality, traffic, and risk of upset sections of EIRs, EISs, FONSIs, initial studies, and negative declarations. Assisted counsel in drafting petitions and briefs and prepared declarations.
- For several large commercial development projects and airports, assisted applicant and counsel prepare defensible CEQA documents, respond to comments, and identify and evaluate "all feasible" mitigation to avoid CEQA challenges. This work included developing mitigation programs to reduce traffic-related air quality impacts based on energy conservation programs, solar, low-emission vehicles, alternative fuels, exhaust treatments, and transportation management associations.

SITE INVESTIGATION/REMEDIATION/CLOSURE

- Technical manager and principal engineer for characterization, remediation, and closure of waste management units at former Colorado oil shale plant. Constituents of concern included BTEX, As, 1,1,1-TCA, and TPH. Completed groundwater monitoring programs, site assessments, work plans, and closure plans for seven process water holding ponds, a refinery sewer system, and processed shale disposal area. Managed design and construction of groundwater treatment system and removal actions and obtained clean closure.
- Principal engineer for characterization, remediation, and closure of process water ponds at a former lanthanide processing plant in Colorado. Designed and implemented groundwater monitoring program and site assessments and prepared closure plan.
- Advised the city of Sacramento on redevelopment of two former railyards. Reviewed work plans, site investigations, risk assessment, RAPS, RI/FSs, and CEQA documents. Participated in the development of mitigation strategies to protect construction and utility workers and the public during remediation, redevelopment, and use of the site, including buffer zones, subslab venting, rail berm containment structure, and an environmental oversight plan.
- Provided technical support for the investigation of a former sanitary landfill that was redeveloped as single family homes. Reviewed and/or prepared portions of numerous documents, including health risk assessments, preliminary endangerment assessments, site investigation reports, work plans, and RI/FSs. Historical research to identify historic waste disposal practices to prepare a preliminary endangerment assessment. Acquired, reviewed, and analyzed the files of 18 federal, state, and local agencies, three sets of construction field notes, analyzed 21 aerial photographs and interviewed 14 individuals associated with operation of former landfill. Assisted counsel in defending lawsuit brought by residents

alleging health impacts and diminution of property value due to residual contamination. Prepared summary reports.

- Technical oversight of characterization and remediation of a nitrate plume at an explosives manufacturing facility in Lincoln, CA. Provided interface between owners and consultants. Reviewed site assessments, work plans, closure plans, and RI/FSs.
- Consultant to owner of large western molybdenum mine proposed for NPL listing. Participated in negotiations to scope out consent order and develop scope of work. Participated in studies to determine premining groundwater background to evaluate applicability of water quality standards. Served on technical committees to develop alternatives to mitigate impacts and close the facility, including resloping and grading, various thickness and types of covers, and reclamation. This work included developing and evaluating methods to control surface runoff and erosion, mitigate impacts of acid rock drainage on surface and ground waters, and stabilize nine waste rock piles containing 328 million tons of pyrite-rich, mixed volcanic waste rock (andesites, rhyolite, tuff). Evaluated stability of waste rock piles. Represented client in hearings and meetings with state and federal oversight agencies.

REGULATORY (PARTIAL LIST)

- In April 2016, prepared supplemental comments on Valero Benicia Crude by Rail Project, focused on on-site impacts and impacts at the unloading terminal, in response to request for a stay to appeal Planning Commission decision.
- In February 2016, prepared comments on Final Environmental Impact Report, Santa Maria Rail Spur Project.
- In February 2016, prepared comments on Final Environmental Impact Report, Valero Benicia Crude by Rail Project.
- In January 2016, prepared comments on Draft Programmatic Environmental Impact Report for the Southern California Association of Government's (SCAG) 2016-2040 Regional Transportation Plan/Sustainable Communities Strategy.
- In November 2015, prepared comments on Final Environmental Impact Report for Revisions to the Kern County Zoning Ordinance - 2015(C) (Focused on Oil and Gas Local Permitting). November 2015.
- In October 2015, prepared comments on Revised Draft Environmental Report, Valero Benicia Crude by Rail Project.
- In September 2015, prepared report, "Environmental, Health and Safety Impacts of the Proposed Oakland Bulk and Oversized Terminal, and presented oral testimony on September 21, 2015 before Oakland City Council on behalf of the Sierra Club.

- In September 2015, prepared comments on revisions to two chapters of EPA's Air Pollution Control Cost Manual: Docket ID No. EPA-HQ-OAR-2015-0341.
- In June 2015, prepared comments on DEIR for the CalAm Monterey Peninsula Water Supply Project.
- In April 2015, prepared comments on proposed Title V Operating Permit Revision and Prevention of Significant Deterioration Permit for Arizona Public Service's Ocotillo Power Plant Modernization Project (5 GE LMS100 105-MW simple cycle turbines operated as peakers), in Tempe, Arizona.
- In March 2015, prepared "Comments on Proposed Title V Air Permit, Yuhuang Chemical Inc. Methanol Plant, St. James, Louisiana".
- In January 2015, prepared cost effectiveness analysis for SCR for a 500-MW coal fire power plant, to address unpermitted upgrades in 2000.
- In January 2015, prepared comments on Revised Final Environmental Impact Report for the Phillips 66 Propane Recovery Project.
- In December 2014, prepared "Report on Bakersfield Crude Terminal Permits to Operate." In response, the U.S. EPA cited the Terminal for 10 violations of the Clean Air Act.
- In December 2014, prepared comments on Revised Draft Environmental Impact Report for the Phillips 66 Propane Recovery Project.
- In November 2014, prepared comments on Revised Draft Environmental Impact Report for Phillips 66 Rail Spur Extension Project and Crude Unloading Project, Santa Maria, CA to allow the import of tar sands crudes.
- In November 2014, prepared comments on Draft Environmental Impact Report for Phillips 66 Ultra Low Sulfur Diesel Project, responding to the California Supreme Court Decision, *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310.*
- In November 2014, prepared comments on Draft Environmental Impact Report for the Tesoro Avon Marine Oil Terminal Lease Consideration.
- In October 2014, prepared: "Report on Hydrogen Cyanide Emissions from Fluid Catalytic Cracking Units", pursuant to the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 79 FR 36880.
- In October 2014, prepared technical comments on Final Environmental Impact Reports for Alon Bakersfield Crude Flexibility Project to build a rail terminal to allow the import/export of tar sands and Bakken crude oils and to upgrade an existing refinery to allow it to process a wide range of crudes.

- In October 2014, prepared technical comments on the Title V Permit Renewal and three De Minimus Significant Revisions for the Tesoro Logistics Marine Terminal in the SCAQMD.
- In August 2014, for EPA Region 6, prepared technical report on costing methods for upgrades to existing scrubbers at coal-fired power plants.
- In July 2014, prepared technical comments on Draft Final Environmental Impact Reports for Alon Bakersfield Crude Flexibility Project to build a rail terminal to allow the import/export of tar sands and Bakken crude oils and to upgrade an existing refinery to allow it to process a wide range of crudes.
- In June 2014, prepared technical report on Initial Study and Draft Negative Declaration for the Tesoro Logistics Storage Tank Replacement and Modification Project.
- In May 2014, prepared technical comments on Intent to Approve a new refinery and petroleum transloading operation in Utah.
- In March and April 2014, prepared declarations on air permits issued for two crude-by-rail terminals in California, modified to switch from importing ethanol to importing Bakken crude oils by rail and transferring to tanker cars. Permits were issued without undergoing CEQA review. One permit was upheld by the San Francisco Superior Court as statute of limitations had run. The Sacramento Air Quality Management District withdrew the second one due to failure to require BACT and conduct CEQA review.
- In March 2014, prepared technical report on Negative Declaration for a proposed modification of the air permit for a bulk petroleum and storage terminal to the allow the import of tar sands and Bakken crude oil by rail and its export by barge, under the New York State Environmental Quality Review Act (SEQRA).
- In February 2014, prepared technical report on proposed modification of air permit for midwest refinery upgrade/expansion to process tar sands crudes.
- In January 2014, prepared cost estimates to capture, transport, and use CO2 in enhanced oil recovery, from the Freeport LNG project based on both Selexol and Amine systems.
- In January 2014, prepared technical report on Draft Environmental Impact Report for Phillips 66 Rail Spur Extension Project, Santa Maria, CA. Comments addressed project description (piecemealing, crude slate), risk of upset analyses, mitigation measures, alternative analyses and cumulative impacts.
- In November 2013, prepared technical report on3333 the Phillips 66 Propane Recovery Project, Rodeo, CA. Comments addressed project description (piecemealing, crude slate) and air quality impacts.
- In September 2013, prepared technical report on the Draft Authority to Construct Permit for the Casa Diablo IV Geothermal Development Project Environmental Impact Report and Declaration in Support of Appeal and Petition for Stay, U.S. Department of the Interior,

Board of Land Appeals, Appeal of Decision Record for the Casa Diablo IV Geothermal Development Project.

- In September 2013, prepared technical report on Effluent Limitation Guidelines for Best Available Technology Economically Available (BAT) for Bottom Ash Transport Waters from Coal-Fired Power Plants in the Steam Electric Power Generating Point Source Category.
- In July 2013, prepared technical report on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063.
- In July 2013, prepared technical report on fugitive particulate matter emissions from coal train staging at the proposed Coyote Island Terminal, Oregon, for draft Permit No. 25-0015-ST-01.
- In July 2013, prepared technical comments on air quality impacts of the Finger Lakes LPG Storage Facility as reported in various Environmental Impact Statements.
- In July 2013, prepared technical comments on proposed Greenhouse Gas PSD Permit for the Celanese Clear Lake Plant, including cost analysis of CO2 capture, transport, and sequestration.
- In June/July 2013, prepared technical comments on proposed Draft PSD Preconstruction Permit for Greenhouse Gas Emission for the ExxonMobil Chemical Company Baytown Olefins Plant, including cost analysis of CO2 capture, transport, and sequestration.
- In June 2013, prepared technical report on a Mitigated Negative Declaration for a new rail terminal at the Valero Benicia Refinery to import increased amounts of "North American" crudes. Comments addressed air quality impacts of refining increased amounts of tar sands crudes.
- In June 2013, prepared technical report on Draft Environmental Impact Report for the California Ethanol and Power Imperial Valley 1 Project.
- In May 2013, prepared comments on draft PSD permit for major expansion of midwest refinery to process 100% tar sands crudes, including a complex netting analysis involving debottlenecking, piecemealing, and BACT analyses.
- In April 2013, prepared technical report on the Draft Supplemental Environmental Impact Statement (DSEIS) for the Keystone XL Pipeline on air quality impacts from refining increased amount of tar sands crudes at Refineries in PADD 3.
- In October 2012, prepared technical report on the Environmental Review for the Coyote Island Terminal Dock at the Port of Morrow on fugitive particulate matter emissions.
- In October 2012-October 2014, review and evaluate Flint Hills West Application for an expansion/modification for increased (Texas, Eagle Ford Shale) crude processing and related modification, including netting and BACT analysis. Assist in settlement discussions.

- In February 2012, prepared comments on BART analysis in PA Regional Haze SIP, 77 FR 3984 (Jan. 26, 2012). On Sept. 29, 2015, a federal appeals court overturned the U.S. EPA's approval of this plan, based in part on my comments. concluding "..we will vacate the 2014 Final Rule to the extent it approved Pennsylvania's source-specific BART analysis and remand to the EPA for further proceedings consistent with this Opinion." Nat'l Parks Conservation Assoc. v. EPA, 3d Cir., No. 14-3147, 9/19/15.
- Prepared cost analyses and comments on New York's proposed BART determinations for NOx, SO2, and PM and EPA's proposed approval of BART determinations for Danskammer Generating Station under New York Regional Haze State Implementation Plan and Federal Implementation Plan, 77 FR 51915 (August 28, 2012).
- Prepared cost analyses and comments on NOx BART determinations for Regional Haze State Implementation Plan for State of Nevada, 77 FR 23191 (April 18, 2012) and 77 FR 25660 (May 1, 2012).
- Prepared analyses of and comments on New Source Performance Standards for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392 (April 13, 2012).
- Prepared comments on CASPR-BART emission equivalency and NOx and PM BART determinations in EPA proposed approval of State Implementation Plan for Pennsylvania Regional Haze Implementation Plan, 77 FR 3984 (January 26, 2012).
- Prepared comments and statistical analyses on hazardous air pollutants (HAPs) emission controls, monitoring, compliance methods, and the use of surrogates for acid gases, organic HAPs, and metallic HAPs for proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 76 FR 24976 (May 3, 2011).
- Prepared cost analyses and comments on NOx BART determinations and emission reductions for proposed Federal Implementation Plan for Four Corners Power Plant, 75 FR 64221 (October 19, 2010).
- Prepared cost analyses and comments on NOx BART determinations for Colstrip Units 1-4 for Montana State Implementation Plan and Regional Haze Federal Implementation Plan, 77 FR 23988 (April 20, 2010).
- For EPA Region 8, prepared report: Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, March 2011, in support of 76 FR 58570 (Sept. 21, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Selective Catalytic Reduction at the Public Service Company of New Mexico San Juan Generating Station, November 2010, in support of 76 FR 52388 (Aug. 22, 2011).

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- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2, Muskogee Units 4 & 5, Northeastern Units 3 &4, October 2010, in support of 76 FR 16168 (March 26, 2011). My work was upheld in: *State of Oklahoma v. EPA*, App. Case 12-9526 (10th Cri. July 19, 2013).
- Identified errors in N_2O emission factors in the Mandatory Greenhouse Gas Reporting Rule, 40 CFR 98, and prepared technical analysis to support Petition for Rulemaking to Correct Emissions Factors in the Mandatory Greenhouse Gas Reporting Rule, filed with EPA on 10/28/10.
- Assisted interested parties develop input for and prepare comments on the Information Collection Request for Petroleum Refinery Sector NSPS and NESHAP Residual Risk and Technology Review, 75 FR 60107 (9/29/10).
- Technical reviewer of EPA's "Emission Estimation Protocol for Petroleum Refineries," posted for public comments on CHIEF on 12/23/09, prepared in response to the City of Houston's petition under the Data Quality Act (March 2010).
- Prepared comments on SCR cost effectiveness for EPA's Advanced Notice of Proposed Rulemaking, Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station, 74 FR 44313 (August 28, 2009).
- Prepared comments on Proposed Rule for Standards of Performance for Coal Preparation and Processing Plants, 74 FR 25304 (May 27, 2009).
- Prepared comments on draft PSD permit for major expansion of midwest refinery to process up to 100% tar sands crudes. Participated in development of monitoring and controls to mitigate impacts and in negotiating a Consent Decree to settle claims in 2008.
- Reviewed and assisted interested parties prepare comments on proposed Kentucky air toxic regulations at 401 KAR 64:005, 64:010, 64:020, and 64:030 (June 2007).
- Prepared comments on proposed Standards of Performance for Electric Utility Steam Generating Units and Small Industrial-Commercial-Industrial Steam Generating Units, 70 FR 9706 (February 28, 2005).
- Prepared comments on Louisville Air Pollution Control District proposed Strategic Toxic Air Reduction regulations.
- Prepared comments and analysis of BAAQMD Regulation, Rule 11, Flare Monitoring at Petroleum Refineries.
- Prepared comments on Proposed National Emission Standards for Hazardous Air Pollutants: and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary

Sources: Electricity Utility Steam Generating Units (MACT standards for coal-fired power plants).

- Prepared Authority to Construct Permit for remediation of a large petroleum-contaminated site on the California Central Coast. Negotiated conditions with agencies and secured permits.
- Prepared Authority to Construct Permit for remediation of a former oil field on the California Central Coast. Participated in negotiations with agencies and secured permits.
- Prepared and/or reviewed hundreds of environmental permits, including NPDES, UIC, Stormwater, Authority to Construct, Prevention of Significant Deterioration. Nonattainment New Source Review, Title V, and RCRA, among others.
- Participated in the development of the CARB document, *Guidance for Power Plant Siting and Best Available Control Technology*, including attending public workshops and filing technical comments.
- Performed data analyses in support of adoption of emergency power restoration standards by the California Public Utilities Commission for "major" power outages, where major is an outage that simultaneously affects 10% of the customer base.
- Drafted portions of the Good Neighbor Ordinance to grant Contra Costa County greater authority over safety of local industry, particularly chemical plants and refineries.
- Participated in drafting BAAQMD Regulation 8, Rule 28, Pressure Relief Devices, including participation in public workshops, review of staff reports, draft rules and other technical materials, preparation of technical comments on staff proposals, research on availability and costs of methods to control PRV releases, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and cost of low-leak technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pumps and Compressors, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak and seal-less technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of controlling tank emissions, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors at Petroleum Refinery Complexes, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 22, Valves and Flanges at Chemical Plants, etc, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pump and Compressor Seals, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability of low-leak technology, and presentation of testimony before the Board.
- Participated in the development of the BAAQMD Regulation 2, Rule 5, Toxics, including participation in public workshops, review of staff proposals, and preparation of technical comments.
- Participated in the development of SCAQMD Rule 1402, Control of Toxic Air Contaminants from Existing Sources, and proposed amendments to Rule 1401, New Source Review of Toxic Air Contaminants, in 1993, including review of staff proposals and preparation of technical comments on same.
- Participated in the development of the Sunnyvale Ordinance to Regulate the Storage, Use and Handling of Toxic Gas, which was designed to provide engineering controls for gases that are not otherwise regulated by the Uniform Fire Code.
- Participated in the drafting of the Statewide Water Quality Control Plans for Inland Surface Waters and Enclosed Bays and Estuaries, including participation in workshops, review of draft plans, preparation of technical comments on draft plans, and presentation of testimony before the SWRCB.
- Participated in developing Se permit effluent limitations for the five Bay Area refineries, including review of staff proposals, statistical analyses of Se effluent data, review of literature on aquatic toxicity of Se, preparation of technical comments on several staff proposals, and presentation of testimony before the Bay Area RWQCB.
- Represented the California Department of Water Resources in the 1991 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on a striped bass model developed by the California Department of Fish and Game.

- Represented the State Water Contractors in the 1987 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on natural flows, historical salinity trends in San Francisco Bay, Delta outflow, and hydrodynamics of the South Bay.
- Represented interveners in the licensing of over 20 natural-gas-fired power plants and one coal gasification plant at the California Energy Commission and elsewhere. Reviewed and prepared technical comments on applications for certification, preliminary staff assessments, final staff assessments, preliminary determinations of compliance, final determinations of compliance, and prevention of significant deterioration permits in the areas of air quality, water supply, water quality, biology, public health, worker safety, transportation, site contamination, cooling systems, and hazardous materials. Presented written and oral testimony in evidentiary hearings with cross examination and rebuttal. Participated in technical workshops.
- Represented several parties in the proposed merger of San Diego Gas & Electric and Southern California Edison. Prepared independent technical analyses on health risks, air quality, and water quality. Presented written and oral testimony before the Public Utilities Commission administrative law judge with cross examination and rebuttal.
- Represented a PRP in negotiations with local health and other agencies to establish impact of subsurface contamination on overlying residential properties. Reviewed health studies prepared by agency consultants and worked with agencies and their consultants to evaluate health risks.

WATER QUALITY/RESOURCES

- Directed and participated in research on environmental impacts of energy development in the Colorado River Basin, including contamination of surface and subsurface waters and modeling of flow and chemical transport through fractured aquifers.
- Played a major role in Northern California water resource planning studies since the early 1970s. Prepared portions of the Basin Plans for the Sacramento, San Joaquin, and Delta basins including sections on water supply, water quality, beneficial uses, waste load allocation, and agricultural drainage. Developed water quality models for the Sacramento and San Joaquin Rivers.
- Conducted hundreds of studies over the past 40 years on Delta water supplies and the impacts of exports from the Delta on water quality and biological resources of the Central Valley, Sacramento-San Joaquin Delta, and San Francisco Bay. Typical examples include:

    1. Evaluate historical trends in salinity, temperature, and flow in San Francisco Bay and upstream rivers to determine impacts of water exports on the estuary;

2. Evaluate the role of exports and natural factors on the food web by exploring the relationship between salinity and primary productivity in San Francisco Bay, upstream rivers, and ocean;
3. Evaluate the effects of exports, other in-Delta, and upstream factors on the abundance of salmon and striped bass;
4. Review and critique agency fishery models that link water exports with the abundance of striped bass and salmon;
5. Develop a model based on GLMs to estimate the relative impact of exports, water facility operating variables, tidal phase, salinity, temperature, and other variables on the survival of salmon smolts as they migrate through the Delta;
6. Reconstruct the natural hydrology of the Central Valley using water balances, vegetation mapping, reservoir operation models to simulate flood basins, precipitation records, tree ring research, and historical research;
7. Evaluate the relationship between biological indicators of estuary health and down-estuary position of a salinity surrogate (X2);
8. Use real-time fisheries monitoring data to quantify impact of exports on fish migration;
9. Refine/develop statistical theory of autocorrelation and use to assess strength of relationships between biological and flow variables;
10. Collect, compile, and analyze water quality and toxicity data for surface waters in the Central Valley to assess the role of water quality in fishery declines;
11. Assess mitigation measures, including habitat restoration and changes in water project operation, to minimize fishery impacts;
12. Evaluate the impact of unscreened agricultural water diversions on abundance of larval fish;
13. Prepare and present testimony on the impacts of water resources development on Bay hydrodynamics, salinity, and temperature in water rights hearings;
14. Evaluate the impact of boat wakes on shallow water habitat, including interpretation of historical aerial photographs;
15. Evaluate the hydrodynamic and water quality impacts of converting Delta islands into reservoirs;
16. Use a hydrodynamic model to simulate the distribution of larval fish in a tidally influenced estuary;
17. Identify and evaluate non-export factors that may have contributed to fishery declines, including predation, shifts in oceanic conditions, aquatic toxicity from

pesticides and mining wastes, salinity intrusion from channel dredging, loss of riparian and marsh habitat, sedimentation from upstream land alternations, and changes in dissolved oxygen, flow, and temperature below dams.

- Developed, directed, and participated in a broad-based research program on environmental issues and control technology for energy industries including petroleum, oil shale, coal mining, and coal slurry transport. Research included evaluation of air and water pollution, development of novel, low-cost technology to treat and dispose of wastes, and development and application of geohydrologic models to evaluate subsurface contamination from in-situ retorting. The program consisted of government and industry contracts and employed 45 technical and administrative personnel.
- Coordinated an industry task force established to investigate the occurrence, causes, and solutions for corrosion/erosion and mechanical/engineering failures in the waterside systems (e.g., condensers, steam generation equipment) of power plants. Corrosion/erosion failures caused by water and steam contamination that were investigated included waterside corrosion caused by poor microbiological treatment of cooling water, steam-side corrosion caused by ammonia-oxygen attack of copper alloys, stress-corrosion cracking of copper alloys in the air cooling sections of condensers, tube sheet leaks, oxygen in-leakage through condensers, volatilization of silica in boilers and carry over and deposition on turbine blades, and iron corrosion on boiler tube walls. Mechanical/engineering failures investigated included: steam impingement attack on the steam side of condenser tubes, tube-to-tube-sheet joint leakage, flow-induced vibration, structural design problems, and mechanical failures due to stresses induced by shutdown, startup and cycling duty, among others. Worked with electric utility plant owners/operators, condenser and boiler vendors, and architect/engineers to collect data to document the occurrence of and causes for these problems, prepared reports summarizing the investigations, and presented the results and participated on a committee of industry experts tasked with identifying solutions to prevent condenser failures.
- Evaluated the cost effectiveness and technical feasibility of using dry cooling and parallel dry-wet cooling to reduce water demands of several large natural-gas fired power plants in California and Arizona.
- Designed and prepared cost estimates for several dry cooling systems (e.g., fin fan heat exchangers) used in chemical plants and refineries.
- Designed, evaluated, and costed several zero liquid discharge systems for power plants.
- Evaluated the impact of agricultural and mining practices on surface water quality of Central Valley steams. Represented municipal water agencies on several federal and state advisory committees tasked with gathering and assessing relevant technical information, developing work plans, and providing oversight of technical work to investigate toxicity issues in the watershed.

AIR QUALITY/PUBLIC HEALTH

- Prepared or reviewed the air quality and public health sections of hundreds of EIRs and EISs on a wide range of industrial, commercial and residential projects.
- Prepared or reviewed hundreds of NSR and PSD permits for a wide range of industrial facilities.
- Designed, implemented, and directed a 2-year-long community air quality monitoring program to assure that residents downwind of a petroleum-contaminated site were not impacted during remediation of petroleum-contaminated soils. The program included real-time monitoring of particulates, diesel exhaust, and BTEX and time integrated monitoring for over 100 chemicals.
- Designed, implemented, and directed a 5-year long source, industrial hygiene, and ambient monitoring program to characterize air emissions, employee exposure, and downwind environmental impacts of a first-generation shale oil plant. The program included stack monitoring of heaters, boilers, incinerators, sulfur recovery units, rock crushers, API separator vents, and wastewater pond fugitives for arsenic, cadmium, chlorine, chromium, mercury, 15 organic indicators (e.g., quinoline, pyrrole, benzo(a)pyrene, thiophene, benzene), sulfur gases, hydrogen cyanide, and ammonia. In many cases, new methods had to be developed or existing methods modified to accommodate the complex matrices of shale plant gases.
- Conducted investigations on the impact of diesel exhaust from truck traffic from a wide range of facilities including mines, large retail centers, light industrial uses, and sports facilities. Conducted traffic surveys, continuously monitored diesel exhaust using an aethalometer, and prepared health risk assessments using resulting data.
- Conducted indoor air quality investigations to assess exposure to natural gas leaks, pesticides, molds and fungi, soil gas from subsurface contamination, and outgasing of carpets, drapes, furniture and construction materials. Prepared health risk assessments using collected data.
- Prepared health risk assessments, emission inventories, air quality analyses, and assisted in the permitting of over 70 1 to 2 MW emergency diesel generators.
- Prepare over 100 health risk assessments, endangerment assessments, and other health-based studies for a wide range of industrial facilities.
- Developed methods to monitor trace elements in gas streams, including a continuous real-time monitor based on the Zeeman atomic absorption spectrometer, to continuously measure mercury and other elements.

- Performed nuisance investigations (odor, noise, dust, smoke, indoor air quality, soil contamination) for businesses, industrial facilities, and residences located proximate to and downwind of pollution sources.

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Design of Gas Turbine Combined Cycle and Cogeneration Systems, Thermoflow, 12/00
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Response to Comment Letter No. G1-79

Adams Broadwell Joseph & Cardozo Title V

Comment G1-79.1

We are writing on behalf of Safe Fuel and Energy Resources California ("SAFER California"), Peter Estrada, Leonardo Parra and Nicolas Garcia to provide comments on the South Coast Air Quality Management District's ("Air District") proposed Title V Significant Permit Revisions for Tesoro Refining & Marketing Co. LLC's ("Applicant") Carson and Wilmington sites (Facility ID Nos. 174655 and 800436, respectively). To implement its proposed Los Angeles Refinery Integration and Compliance Project ("Project"), the Applicant submitted 13 applications for revisions to the Title V permits for its Carson site (567643, 567645, 567646, 567647, 567648, 567649, 575837, 575838, 575839, 575840, 575841, 578248 and 578249) and five applications for revisions to the Title V permits for its Wilmington site (567619, 567439, 575874, 575875 and 575876).

The Project will interconnect operations at the two sites. Among other components, the Project will increase processing capability at the Wilmington site by 6,000 barrels per day by increasing the firing rate of Heater H-100 which serves the fractionator column of the Delayed Coking Unit at the Wilmington site. In addition, the Project would increase the capacity of the Hydrocracker Unit at the Carson site by approximately 10 percent. The Project also includes modifications to G1-79.1

the Liquified Petroleum Gas ("LPG") Railcar Loading/Unloading Rack, enabling the Carson site to unload an additional 4,000 barrels per day of LPG. G1-79.1 cont'd.

Response G1-79.1

Most of Comment G1-79.1 accurately summarizes changes to be made at the Refinery as part of the proposed project. However, the portion of the comment that references increasing the firing rate of the DCU H-100 heater is not consistent with Section 2.7.1.3 of the FEIR, which states that no physical modifications will be made to the heater. As part of the project, the Title V Permit will be revised to reflect the heater's actual maximum level of operation (302.4 mmBtu/hr) rather than the lower level of operation guaranteed by the manufacturer (252 mmBtu/hr). The heater has operated above 252 mmBtu/hr in the past. Nonetheless, the DEIR made the conservative assumption that the change in permit description would allow Tesoro to increase the maximum operation of DCU H-100 heater from 252 mmBtu/hr to 302.4 mmBtu/hr. In order to ensure that this assumed increase in operations would not result in any increase in emissions, the SCAQMD imposed a new permit condition that limits daily emissions of criteria pollutants from the H-100 unit to levels that would be generated if the unit were never operated above 252 mmBtu/hr. These limits apply to mass emissions of CO, NOx, SOx, particulate matter less than ten microns in diameter (PM10), and volatile organic compounds (VOC).

Comment G1-79.2

The modifications covered in the proposed Title V Significant Permit Revisions cover only a fraction of the changes described in the Air District's Draft Environmental Impact Report ("DEIR") for the Project. Specifically, the proposed Title V revisions cover two heaters (Wilmington Heater H-100 and Carson No. 51 vacuum heater), the shutdown of the Wilmington FCCU, additions of various non-emitting equipment, modifications to the No. 5 Flare System, and various fugitive emission sources. There are numerous remaining components of the Project that are not covered in the proposed Title V revisions.

We reviewed the Air District's proposed Title V revisions with the help of technical expert Phyllis Fox, Ph.D., QEP, PE, DEE[1] and found that: (1) the proposed Title V modifications for both the Wilmington and Carson Operations are inconsistent with many of the assumptions used in the DEIR to analyze the change in emissions from the Project; and (2) that the modifications for both the Wilmington and Carson Operations allow much higher emission increases of NOx than assumed in the DEIR. If the Title V emissions changes were used in the DEIR's operational emission analysis, the Project would result in significant emission increases of NOx.[2] Therefore, either the Air District must revise the Title V permits to ensure that the assumed emission reductions in the DEIR are achieved, or the Air District must revise the DEIR to use the Project's correct emission increases.

G1-79.2

[1] Dr. Fox's comments and curriculum vitae are attached and submitted in addition to the comments in this letter.

[2] The DEIR concluded that the Project would not result in any significant changes in emissions (see DEIR, Table 4.2-4).

Response G1-79.2

The Refinery submitted permit applications for portions of the proposed project which will commence construction in the near future. SCAQMD Rule 205 limits permits to construct to one year from issuance, therefore permit applications for other portions of the proposed project to be constructed later in the project schedule will be submitted to SCAQMD at a later date and prior to commencement of construction of those portions of the proposed project. Permit applications to be submitted at a later date will have to be consistent with the applicable analyses included in the DEIR. The draft Title V permit for later applications will be released for public review consistent with SCAQMD Rule 212 and Regulation XXX requirements. In other words, the DEIR analyzes the whole of the project even though permit applications for some project components have not yet been received by SCAQMD.

The comment suggests that emissions calculations prepared for the Title V permit are inconsistent with and allow much higher emissions than those evaluated by the DEIR. The emission calculation methodologies required to comply with SCAQMD New Source Review (NSR) regulations and other permitting requirements and those required to comply with CEQA are different and cannot be directly compared. However, emissions calculations for each program (NSR/permitting and CEQA) were performed in accordance with current SCAQMD policy, and the permit modification conditions will not allow for greater emissions than were analyzed in the DEIR.

Further, as described in Response G1-79.1, no physical modifications will be made to the heater. Rather, as part of the project, the Title V Permit will be revised to reflect the heater's actual maximum level of operation (302.4 mmBtu/hr) rather than the lower level of operation guaranteed by the manufacturer (252 mmBtu/hr). The heater has operated above 252 mmBtu/hr in the past. Nonetheless, the DEIR made the conservative assumption that the change in permit description would allow Tesoro to increase the maximum operation of Heater H-100 from 252 mmBtu/hr to 302.4 mmBtu/hr. In order to ensure that this assumed increase in operations would not result in any increase in emissions, the SCAQMD imposed a new permit condition that limits daily emissions of criteria pollutants from the H-100 unit to levels that would be generated if the unit were never operated above 252 mmBtu/hr. These limits apply to mass emissions of CO, NOx, SOx, PM10, and VOC.

The comment summarizes the conclusions of the letter, with specific comments made in more detail in the remainder of the letter. Responses to the detailed comments are included below (see Responses G1-79.4 through G1-79.16.)

Comment G1-79.3

I. **STATEMENT OF INTEREST**

SAFER California advocates for safe processes at California refineries to protect the health, safety, the standard of life and the economic interests of its members. For this reason, SAFER California has a strong interest in enforcing environmental laws which require the disclosure of potential environmental impacts of, and ensure safe operations and processes for, California oil refineries. Failure to adequately address the environmental impacts of crude oil and fuel products transport, refining, storage and distribution processes poses a substantial

G1-79.3

threat to the environment, worker health, surrounding communities, and the local economy.

Refineries and fuel storage and distribution facilities are uniquely dangerous and capable of generating significant fires and the emission of hazardous and toxic substances that adversely impact air quality, water quality, biological resources and public health and safety. These risks were recognized by the Legislature and Governor when enacting SB 54 (Hancock). Absent adequate disclosure and mitigation of hazardous materials and processes, refinery workers and surrounding communities may be subject to chronic health problems and the risk of bodily injury and death.

Poorly planned refinery and fuel products storage and distribution projects also adversely impact the economic wellbeing of people who perform construction and maintenance work in these facilities and the surrounding communities. Plant shutdowns in the event of accidental release and infrastructure breakdown have caused prolonged work stoppages. Such nuisance conditions and catastrophic events impact local communities and can jeopardize future jobs by making it more difficult and more expensive for businesses to locate and people to live in the area. The participants in SAFER California are also concerned about projects that carry serious environmental risks and public service infrastructure demands without providing countervailing employment and economic benefits to local workers and communities.

G1-79.3 cont'd.

The members represented by the participants in SAFER California live, work, recreate and raise their families in Los Angeles County, including in or near the City of Carson and the community of Wilmington. Accordingly, these people would be directly affected by the Project's adverse environmental impacts. The members of SAFER California's participating unions may also work at the facility itself. They will, therefore, be first in line to be exposed to any hazardous materials, air contaminants, and other health and safety hazards, that exist onsite.

These comments are also submitted on behalf of individuals who reside and/or work in the Project area, including Peter Estrada, Leonardo Parra and Nicolas Garcia.

Response G1-79.3

The comment is not specific to the proposed project or the draft Title V permits. Therefore, no response is needed.

Comment G1-79.4

II. WILMINGTON TITLE V PERMIT MODIFICATIONS

A. The Proposed Modifications to the DCU H-100 Heater would Increase Daily Criteria Pollutant Emissions

The Project increases the firing rate of heater H-100 by 20 percent, from the design heat release basis of 252 MMBtu/hr to the maximum heat release basis of 302.4 MMBtu/hr.[3] The increased firing rate will increase emissions (in direct proportion).[4] Notably, however, the DEIR concluded that the increased firing rate would ***reduce*** emissions of all criteria pollutants except for SOx. Dr. Fox explains in her attached comments that the Air District achieved these reductions by artificially inflating the baseline emissions.[5]

The DEIR reports the following emissions reductions for heater H-100: G1-79.4

- NOx: -171.03 lbs/day
- CO: -5.14 lbs/day
- PM10: -0.98 lb/day
- PM2.5: -0.98 lb/day
- VOC: -0.43 lb/day

The Air District must revise the Title V permit to impose enforceable emission limits ensuring that these reductions are achieved, and the Air District must revise the DEIR to correct the heater H-100 emission calculations using the correct baseline (daily average emissions in the years 2012 and 2013, ***not*** the 98th percentile of the maximum emissions).

[3] DEIR pp. 1-11, 1-12.
[4] **Attachment A**: Letter from Dr. Phyllis Fox to Rachael Koss, June 9, 2016, p. 3 ("Fox Comments").
[5] *Id.*

Response G1-79.4

The comment: (1) asks how a 20% increase in the DCU H-100 heater's design permit firing rate can result in emission reductions; (2) requests revisions to the Title V permit to impose enforceable emission limits ensuring that the expected emission reductions are achieved; and (3) suggests that the DEIR's emissions analysis should use a baseline consisting of average daily emissions instead of a 98th percentile baseline.

First, to clarify, the revision to the DCU H-100 heater Title V permit description will result in emission reductions because (1) the heater has operated above the guaranteed operation level of 252 mmBtu/hr in the past, and (2) the SCAQMD will impose enforceable mass emission limits that will cap emissions at the level of 252 mmBtu/hr (see "Emissions and Requirements" of the equipment description section of the draft Title V permit). Recordkeeping, as imposed by the Title V permit, will ensure compliance with these emission limits. Currently the permit has no conditions limiting mass emissions. No physical changes will be made to the DCU H-100 heater. Rather, the Title V Permit will be revised to reflect the heater's actual maximum level of operation (302.4 mmBtu/hr) rather than the lower level of operation guaranteed by the manufacturer (252 mmBtu/hr). The DEIR made the conservative assumption that the change in permit description would allow Tesoro to increase the maximum operation of Heater H-100 from

252 mmBtu/hr to 302.4 mmBtu/hr. The SCAQMD imposed a new permit condition that limits daily emissions of criteria pollutants from the H-100 unit to levels that would be generated if the unit were never operated above 252 mmBtu/hr.

As further explained in G1-79.5, the SCAQMD properly applied the applicable new source review regulations[237] to establish the potential to emit (PTE) for the DCU H-100 heater. For CEQA purposes the baseline period was 2012-2013. Because the DCU H-100 heater has 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 calculations are not directly comparable. Nonetheless, the SCAQMD is also imposing criteria pollutant mass emission limitations in the heater permit for the first time. The Title V permit will include enforceable limits for NOx, SOx, PM, ROG, and CO (shown at the end of this response) for the DCU H-100 heater as a result of the proposed project. Therefore, although it is assumed that the permitted firing rate will be higher, the heater can only be operated in a way so that hourly and daily emissions from the heater do not exceed the new emission limits. The permit revision will include enforceable conditions to monitor and enforce compliance with these limits through continuous emissions monitoring system (CEMS) data or annual source testing (see Condition D29.XX), depending on the pollutant. In addition, there are existing permit conditions that require recordkeeping (e.g., CEMS data, source testing results, and operating information) which will also apply to the proposed project permit revision. Thus, the DEIR analysis correctly shows decreases in emissions from the DCU H-100 heater because typical daily emissions during the baseline period (which were not subject to the mass emission limits in the current permit) are higher than the mass emission limits which will be imposed as part of the proposed project.

Second, the analysis in the DEIR, which compares 98th percentile baseline emissions to the SCAQMD's proposed maximum emissions limits discussed in this response, is accurate. The SCAQMD CEQA significance threshold is based on "peak daily" emissions, and therefore, the comparison is based on pre-project near "peak day" to post-project "peak day". The selection of a near-peak, 98th percentile emission baseline is reasonable and supported by substantial evidence. The Supreme Court has specifically acknowledged that *peak* impacts may be an appropriate metric in measuring baseline refinery operations.[238] While reliance on a peak emissions figure that is a gross outlier could be inappropriate because it may not be a realistic measurement of existing conditions, the use of a peak figure that realistically represents actual operations is reasonable. With this guidance and the consideration that Refinery operations fluctuate on a daily basis in mind, the SCAQMD established baseline emissions using the 98th percentile of peak daily emissions during the 2012-2013 monitoring period to avoid using a pure peak daily emission baseline that may be an outlier.[239] The 98th percentile represents operating conditions that are two percent less than the peak day in the baseline period. It is a metric that is higher than an average emission measurement, but lower than a peak emission measurement. Here, the DEIR calculated baseline criteria pollutant emissions using actual emissions data, not hypothetically permissible emissions. Operating conditions at the Refinery were at or above 98th

[237] SCAQMD Rule 2005 for NOx and SOx. SCAQMD Regulation XIII for PM, ROG, and CO.

[238] See *Communities for a Better Environment*, 48 Cal.4th at 328 ("In some circumstances, peak impacts or recurring periods of scarcity may be as important environmentally as average conditions.")

[239] See Draft EIR 4-21.

percentile conditions 15 days during the baseline period and, therefore, are representative of the existing limits of *actual* operating conditions.

Further, the 98th percentile methodology and similar approaches are established metrics for analysis of criteria pollutant emissions. The 98th percentile approach is based on the U.S. EPA's methodology for establishing the Primary National Ambient Air Quality Standards (NAAQS) for Nitrogen Dioxide (NO_2) (see page 4-21 of the DEIR.). The U.S. EPA uses a similar standard (i.e., 99th percentile) —an approach that produces less conservative measurements closer to peak emissions figures— for sulfur dioxide. The 98th percentile emissions data was selected specifically because it is the metric used in the U.S. EPA's Primary NAAQS NO_2 and NOx, a precursor to NO_2 as well as ozone, is a primary pollutant emitted by refineries (see page 4-21 of the DEIR). Thus, the DEIR's use of the 98th percentile methodology to calculate the baseline for all criteria pollutants for process heaters with proposed modifications was based on accepted national standards for relevant pollutants and provided a more conservative emission rate than those standards or California law could otherwise allow. Use of the actual achieved peak could have been an anomaly, which would have underestimated the proposed project impacts. By depressing the baseline peak daily emissions by two percent, the proposed project impacts are conservatively evaluated.

Because the DEIR relied on actual emissions data at the Refinery and even discounted those results using a recognized criteria pollutant metric to ensure that the baseline figure realistically reflected normal operating conditions, the use of the 98th percentile measurement for criteria pollutants is supported by substantial evidence.

However, the DEIR did not calculate projected post-project emissions using a "daily average" metric; rather, the DEIR sought to determine the worst-case construction and operating scenarios and calculated emissions using *peak* construction and *peak* normal operating days. (See DEIR page 4-9). Thus, while these comments are correct that the baseline and post-project emissions methodologies are different, they actually tend toward overestimation of impacts because the DEIR compares below-peak baseline emissions to peak projected emissions. In instances where equipment had no existing emissions limits in the baseline, permit limits have been imposed which result in an emissions reduction from the baseline emissions. Thus, the emissions methodology that the DEIR used in its emissions analysis does not underestimate the proposed project's impacts.

In addition, comments also claimed that the DEIR's baseline for modified heaters is flawed because it does not report average NOx emissions. Consistent with CEQA Guidelines § 15064.7, the SCAQMD has established significance thresholds that are quantitative. The SCAQMD's significance thresholds are peak daily emissions thresholds. As such, average daily emissions are not a representative emission metric to compare to the threshold. The DEIR correctly uses incremental change associated with the proposed project derived from the comparison of the post-project peak daily potential emissions to the 98th percentile actual emissions as described above with the net result compared to the SCAQMD's significance thresholds.

The analysis compares the baseline to the maximum emissions permitted by the permit in the post-project condition. Because the comparison assumes peak post-project emission limits, against slightly less than peak pre-project conditions, it actually overestimates emissions impacts. Accordingly, there is no need to revise the emission calculation in the DEIR.

The SCAQMD has imposed permit conditions that limit emissions as follows:

Emissions and Requirements: NOx: 18.40 lb/hr; SOx: 14.08 lb/hr

A63.XX The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 37 lb in any one day
PM10	Less than or equal 0.00510 Lb/mmBtu
ROG	Less than or equal to 35 lb in any one day
ROG	Less than or equal to 0.00482Lb/mmBtu
CO	Less than or equal to174 lb in any one day
CO	Less than or equal to 0.02397Lb/mmBtu

A63.YY The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
NOx	Less than or equal to 181.44 lb/day
SOx	Less than or equal to 250 lb/day

These conditions ensure that the proposed project emissions will not exceed those analyzed in the DEIR (see page 4-16 through 4-18 of the DEIR).

Comment G1-79.5

Further, the application for the heater H-100 firing rate states that, "Tesoro does not propose to increase the potentials to emit for this heater."[6] Yet, as Dr. Fox points out, "the proposed daily SOx limit of 250 lbs/day and the proposed daily ROG limit of 35 lbs/day are much higher than the potential to emit for heather H-100."[7] The 8 lbs/day difference between the proposed ROG limit and potential to emit (27 lbs/day) tips the total Project ROG emissions of 49.09 lbs/day over the Air District's G1-79.5

CEQA significance threshold of 55 lbs/day.[8] Notably, the DEIR operational emissions analysis assumes that the H-100 duty bump would *reduce* VOC emissions. Contrary to its application, Tesoro does, indeed, propose to increase the potentials to emit for heater H-100, and the proposed Title V permit does nothing to ensure that the emission assumptions in the DEIR are achieved. G1-79.5 cont'd.

[6] SCAQMD Application 567439, pdf 14.
[7] Fox Comments, p. 3.
[8] *Id.*

Response G1-79.5

Application Number (AN) 567439 identified in Footnote 6 is the engineering permit evaluation for the DCU H-100 heater provided in response to a public records request (PRR). However, review of the PRR response does not list the lower heater potentials to emit (PTEs) of 27 lb/day ROG or 133 lb/day SOx for the existing heater as suggested by the comment. Rather, review of the PRR response shows PTEs of 35 lb/day ROG and 250 lb/day SOx[240]. However, draft submittals of permit applications for the DCU H-100 heater by Tesoro evaluated emissions from this heater using incorrect potentials to emit (27 lb/day ROG and 133 lb/day SOx) based on natural gas instead of Refinery fuel gas.

In subsequent analyses, SCAQMD engineering staff corrected these PTEs to reflect updates of local rules and to reflect actual recent operating conditions of the DCU H-100 heater using Refinery fuel gas, which is currently combusted in the heater. The pre- and post-project PTEs for the DCU H-100 heater are the same (35 lb/day of ROG and 250 lb/day of SOx). The correct PTEs were used in the DEIR and the permitting analysis. See Response G1-79.4 regarding the imposition of enforceable emission limitations that ensure that the emission reductions evaluated in the DEIR are correct and enforceable.

Comment G1-79.6

B. Permit Conditions A195.XX and A195.YY Allow for Exceedances of 1-Hour NOx and SOx Ambient Air Quality Standards

Draft permit Condition S11.X sets an hourly limit on NOx of 18.4 lbs/hr and on SOx of 14.08 lbs/hr. These hourly emission limits are consistent with emissions used in the criteria pollutant air quality modeling for heater H-100.[9] However, Dr. Fox points out that other conditions in the draft permit "weaken these limits by specifying an averaging time that allows exceedances of these 1-hour limits to be averaged out."[10] Specifically, Condition A195.XX provides that compliance with the "hourly" NOx limit is based on a rolling 24-hour average. Similarly, Condition A195.YY provides that compliance with the 1-hour SOx limit is based on a rolling 24-hour average. According to Dr. Fox, "[t]his type of averaging convention allows much higher hourly emissions than were assumed in the criteria pollutant modeling, which was performed to demonstrate compliance with ambient air quality standards."[11] Dr. Fox goes on to explain that a rolling 24-hour average "smooths out emissions data and eliminates peak hourly values that would otherwise exceed the hourly values used in the air dispersion modeling analysis and limited in Condition S11.X."[12] A rolling 24-hour average "guts the intent of the 1-hour limit in Condition S11.X, which is essential to assure that hourly average ambient air quality standards are not exceeded."[13] G1-79.6

9 *Id.*
10 *Id.*, p. 4.
11 *Id.*
12 *Id.*
13 *Id.*

240 SCAQMD Engineering Permit Evaluation for Application Number 567439, 12/15/15 page 8 of 30 found in pdf on electronic page 97.

Response G1-79.6

The comment refers to the NOx permit limitation of 18.4 lb/hr (rolling 24-hour average). Note that the draft Title V permit also imposes a daily limit of 181.44 lb/day that is more restrictive than the hourly limit (i.e., 18.4 lb/hr x 24 hr/day = 441.6 lb/day). Hourly NO_2 modeling was not performed at 18.4 lb/hr, rather, in order to ensure that modeling was more protective, modeling was performed based on a much larger value of 36.72 lb/hr, which is the theoretical maximum hourly emissions value for this heater. The theoretical maximum hourly 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[241]. The NOx emissions rate modeled was based on the maximum hourly emissions less the emissions during the baseline period to result in 22.03 lb/hr. Baseline emissions were appropriately subtracted from the worst-case emissions to avoid double counting in subsequent analyses when the modeled results are added to the monitored background NO_2 concentrations (reference FEIR Table 4.2-12). Using the theoretical maximum emission rate as a basis in the ambient air quality modeling, which is much greater than the emissions limit enforced by the permit, represents a worst-case scenario, which is more protective to the environment. As summarized in FEIR Table 4.2-12, Federal and State NO_2 1-hour standards are not exceeded by the theoretical maximum hourly NOx emissions of this heater.

Response G1-79.4 also summarizes the permit limitations, including a daily SOx restriction in addition to the rolling 24-hour average that ensures stringent limitation of SOx emissions. Additional modeling was performed to determine the hourly rate of SO_2 which could potentially cause the ambient air quality standards for SOx to be exceeded. As indicated in Table 79.6-1, the resulting value of the modeling is 370 lb/hr (equivalent to 8,880 lb/day), which far exceeds the proposed hourly and daily limits of 14.08 lb/hr and 250 lb/day (based on historic operating data) imposed by draft Title V Emissions and Requirements and permit conditions A63.YY.

Table 79.6-1

Comparison of SOx Modeling and Draft Title V Permit Conditions for the DCU H-100 Heater

Emission Rate	Emissions (lb/hr)	Emissions (lb/day)
Rate at Which the Ambient Air Quality Standard is Exceeded	370	8,880
Draft Permit	14.08	250

Thus, SOx emissions limitations restricted and enforceable by the draft Title V permit are well below those which would cause an exceedance of the ambient air quality standards.

[241] 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. Daily data from Tables A-2 and A-3 are divided by 24 to obtain hourly values.

The comment suggests that "rolling" 24-hour average hourly limits may allow exceedances of NO_2 or SO_2 NAAQS in a given hour. However, the comment fails to consider the protective impact of the daily NO_2 and SO_2 limits. Since the hourly emissions that would cause an exceedance of the standard are greater than the allowable daily emissions, the ambient air quality standards for SOx cannot be exceeded as a result of the proposed project, and no revision to draft Title V permit condition A195.YY is required.

It should be noted that during startup and shutdown conditions, SOx daily mass emissions will be less than normal operating conditions, because the firing rate is low and the fuel gas sulfur content, upon which SOx emissions are determined, does not change due to the startup or shutdown of a heater.

Comment G1-79.7

Dr. Fox points out that this problem is particularly critical for NOx. This is because the DEIR reports a 1-hour average NOx concentration of 301.4 ug/m^3 compared to the State 1-hour ambient air quality standard of 339 ug/m^3. The DEIR also reports a total 1-hour average NOx concentration of 184.9 ug/m^3, compared to the federal 1-hour ambient air quality standard of 188 ug/m^3. The values reported in the DEIR are very close to the State and federal standards. Thus, if the modeled NOx concentration increased by just 3.2 ug/m^3, from 38.6 ug/m^3 to 41.8 ug/m^3, the total NOx concentration would exceed the federal 1-hour NOx standard.[14] According to Dr. Fox, given the Air District's proposed permit conditions allowing the use of a 24-hour rolling average, it "is readily foreseeable" that the total NOx concentration would exceed the federal 1-hour NOx standard.[15] In Dr. Fox's opinion, the rolling 24-hour average may also allow violations of the 1-hour SOx State (655 ug/m^3) and federal (196 ug/m^3) ambient air quality standards.[16] The proposed 24-hour averaging times allows potentially significant unmitigated air quality impacts. Therefore, the Air District must eliminate the rolling average conventions in Conditions A195.XX and A195.YY.

G1-79.7

G1-79.7 cont'd.

[14] *Id.*
[15] *Id.*
[16] *Id.*

Response G1-79.7

It is incorrect to compare stack emissions directly to ambient air quality standards. Stack emissions need to be modeled in order to estimate the corresponding ground level concentration in order to compare that concentration with ambient air quality standards. As described in Response G1-79.6, NO_2 modeling was performed based on the theoretical maximum hourly emissions less the emissions during the baseline period. As summarized in FEIR Table 4.2-12, Federal and State NO_2 1-hour standards are not exceeded by the theoretical maximum hourly NOx emissions of this heater. Therefore, no revision to Title V permit condition A195.XX is required.

Refinery fuel gas is delivered to heaters from the Refinery fuel Gas System. The sulfur content of Refinery fuel gas does not change during the startup or shutdown of a process heater. Additionally, the firing rate of the heater is typically lower during startup and shutdown events than during normal operating conditions. Therefore, multiplying the Refinery fuel gas sulfur concentration (which is the same during a heater startup/shutdown as during the heater's normal operation) by a lower than normal firing rate during startup and shutdown conditions results in SOx emissions less than normal operating conditions. SO_2 modeling was based on the daily permit limit of 250 lb/day. However, to address the comment that the rolling average could exceed the ambient air quality standards, additional modeling was performed to determine the hourly rate of SOx which could potentially cause the ambient air quality standards for SO_2 to be exceeded. As indicated in table 79.6-2, the result of the modeling is 370 lb/hr (equivalent to 8,880 lb/day). This is far greater than the proposed project's Title V permit emission limits (14.08 lb/hr and 250 lb/day SOx).

Since the projected hourly emissions that could cause an exceedance of the standard are greater than the allowable daily emissions of the draft Title V permit, the ambient air quality standards for SOx will not be exceeded as a result of the proposed project. No revision to draft Title V permit condition A195.YY is required.

Comment G1-79.8

C. Proposed Permit Condition A99.X Allows for Exceedance of Hourly NOx Limit

Proposed permit Condition A99.X sets an exception to the new 18.40 lbs/hr hourly NOx limit as follows:

> The 18.40 lb/hr NOx emission limit(s) shall not apply during the heater startup, shutdowns or refractory dryout periods. For the purpose of this exception, each startup event shall not exceed 48 hours, not including refractory dryout period up to 48 additional hours and each shutdown event shall not exceed 24 hours.

Dr. Fox explains that this exception is problematic for three reasons. First, it "would allow unlimited increases in NOx emissions. sufficient to violate the State and federal 1-hour NOx ambient air quality standards."[17] Second, automatic exemptions from permit limits during startup and shutdowns are not permitted.[18] Finally, the DEIR did not evaluate the impact of this exception (i.e., exemptions from hourly NOx limits) on ambient air quality.[19] Therefore, the Air District must eliminate the exception in Condition A99.X.

G1-79.8

[17] *Id.*, p. 5.
[18] *Sierra Club v. Environmental Protection Agency*. 2008 WL 5264663 (D.C. Cir. Dec. 19, 2008).
[19] Fox Comments, p. 5.

Response G1-79.8

See Response G1-79.6 regarding the NO_2 emissions modeling included in the DEIR.

Contrary to the unlimited increases claimed in the comment, during typical startup and shutdown conditions, NO_2 daily mass emissions will be less than normal operating conditions because the firing rate is lower than normal operating conditions. However, startup and shutdown pollutant emissions can be higher than normal operating conditions on an hourly basis because the burners and the pollution control equipment are not operating in optimal ranges (temperature, flow rate, etc.) until normal operating conditions are reached. Therefore, SCAQMD is imposing startup and shutdown conditions in accordance with EPA's startup shutdown and malfunction requirements (40 CFR Part 52).

The 24/48-hour limitation included in Title V permit condition A99.X imposes an enforceable time limit for startup, shutdown and refractory dry-out occurrences for this heater, thus limiting emissions during these occurrences. Previously there was no limitation on startup or shutdown duration. During these startup and shutdown occurrences, NOx emissions are not controlled by pollution control equipment operating at its peak efficiency, but they are not unlimited. The startup and shutdown provision is provided to enable the heater operation to stabilize at a rate where the SCR can be placed in operation without the possibility of damaging the SCR catalyst. If ammonia, which is required for the SCR to function properly, is injected at low temperatures, SCR catalyst damage or plugging and excessive ammonia emissions can occur. Therefore, existing permit condition E54.9 requires that the SCR be fully functional when heater exhaust gas reaches 550^{0}F, thereby ensuring that compliance with the hourly limit is achieved without delay. Providing shutdown and startup duration limitations meet EPA's current startup, shutdown and malfunction requirements.

The startup and shutdown events already occur and will not change as a result of the proposed project. No change to ambient air quality would occur. In other words, pre-project startup and shutdown emissions compared to post-project startup and shutdown emissions are the same. This results in a net emission increase of zero and does not require further analysis under CEQA. This information is represented in Chapter 4, Table 4.2-4, as well as Appendix B-3 Table 6 to the DEIR. Permit condition A99.X would not cause the proposed project to ". . . exceed the Air District's 55 lb/day NOx CEQA significance threshold". Because there is no change in daily pre-project and post-project startup or shutdown emissions, and any additional startup or shutdown events are speculative, proposed permit condition A99.X did not require separate evaluation in the DEIR and it is appropriately imposed on the DCU H-100 heater. The permit condition actually adds limitations on startups and shutdowns that do not currently exist, so it will not result in a significant increase in emissions.

Comment G1-79.9

D. Stack Tests are Insufficient to Ensure Compliance with Emission Limits

The draft permit provides that compliance with the emission limits for PM10, ROG and CO would be determined using an annual stack test,[20] while compliance with NOx and SOx limits would be based on the use of a continuous emission monitoring system ("CEMS"). Dr. Fox explains that "annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions."[21] Since CEMS are available for ROG and CO, Dr. Fox recommends that CEMS be required to determine compliance with the proposed ROG and CO emission limits.[22] Dr. Fox points out that accurately verifying compliance with the ROG limit is particularly important because the Air District "is in serious nonattainment with ozone ambient air quality standards."[23] G1-79.9

[20] Wilmington Draft Title V Permit, Condition A63.XX.
[21] Fox Comments, p. 5.
[22] *Id.*
[23] *Id.*

Response G1-79.9

Permit conditions for this heater are designed to ensure compliance with all applicable rules and regulations. As stated, for NOx and SOx emissions monitoring, a CEMS is operated as required by the SCAQMD RECLAIM program. For CO and VOC emissions, periodic source testing satisfies the applicable periodic monitoring requirements of local rules, including SCAQMD Rule 3004(a)(4)(c) periodic monitoring requirements.

The comment suggests that since annual source testing is "staged", it is unreliable for ensuring routine compliance with PM10, ROG and CO limits. This assumes there are no testing parameters that need to be followed, which is not the case. Draft Title V permit condition D29.XX not only requires that testing follow approved SCAQMD methods[242], but that testing also follow a source test protocol which has been submitted by Tesoro and approved by the SCAQMD prior to the test. Condition D29.XX also requires that the test shall be conducted when the equipment is operating at 80 percent or greater of the maximum design capacity. This 80 percent or greater requirement ensures that tests are representative of operating conditions and not "staged" conditions during testing. In addition, there are other methods for assuring compliance with permit requirements. For example, the SCAQMD can, and has in the past, performed unannounced compliance testing at refineries in the basin.

It should be noted that NOx, PM10, VOC, and CO emissions are inter-related. To control NOx, flame temperature and/or excess air need to be reduced. However, heater operation at low flame temperature and low excess air level can result in incomplete combustion and the formation of excessive PM10, VOC, and CO. Therefore, it is not feasible to adjust the combustion parameters in a process heater with stringent NOx limits, such as the DCU H-100 heater, in an attempt to reduce other parameters, such as PM10, VOC, and CO emissions, without altering the NOx emissions to a state of non-compliance. Such NOx non-compliance would be detected in the CEMS results. Thus, any attempt to "stage" the source test to artificially lower emissions would be detectable. Therefore, periodic source testing is an appropriate compliance assurance measure and is appropriately imposed as a permit requirement. While there are CO CEMS available for a process heater stack, a CO CEMS is not necessary in this case as described above. There are no PM10 or VOC CEMS available for a process heater stack that is approved by the SCAQMD.

[242] SCAQMD Source Test Methods available at http://www.aqmd.gov/home/library/documents-support-material, and click on the methods/proceed tab.

Comment G1-79.10

III. CARSON TITLE V PERMIT MODIFICATIONS

A. The Proposed Permits Allows for Greater Emissions from the Carson No. 51 (D63) Vacuum Unit Heater than Were Analyzed in the DEIR

The Applicant proposes to modify Carson No. 51 Vacuum Unit Heater (D63) to increase the maximum permitted firing rate from 276.95 MMBtu/hr to 360 MMBtu/hr.[24] The increase in firing rate will increase emissions.[25] The draft permit sets new limits in Conditions A99.X1 (startup and shutdown exemption), A195.X1 (NOx 24 hr average), B61.8 (fuel gas H_2S limit), C1.X1 (heat input limit) and D29.X1 (test methods). The draft permit sets the following emission limits for the vacuum unit heater: G1-79.10

- CO: 29.6 lbs/MMSCF[26] natural gas
- PM: 6.3 lbs/MMSCF natural gas
- VOC: 5.9 lbs/MMSCF natural gas
- NOx: 2.62 lbs/day natural gas.[27]

Dr. Fox converted these limits into pounds per day, assuming the maximum firing rate of 360 MMBtu/hr and the higher heating value of natural gas (1050 MMBtu/MMSCF):

- CO: 244 lbs/day (DEIR:247 lbs/day)
- PM: 52 lbs/day (DEIR: 53 lbs/day)
- VOC: 48 lbs/day (DEIR: 50 lbs/day)
- NOx: 2.62 lbs/day (DEIR: 3.93 lbs/day)

G1-79.10 cont'd.

These are consistent with the limits in Condition A63.3. However, Dr. Fox points out that these limits allow greater emissions than were analyzed in the DEIR.[28] Thus, the Air District must adjust the limits to reflect the DEIR analysis.

[24] DEIR, p. B-3-56.
[25] Fox Comments, p. 6.
[26] MMSCF = millions of standard cubic feet.
[27] Carson Draft Title V Permit, pdf 1.
[28] Fox Comments, p. 6.

Response G1-79.10

The current firing rate of the No. 51 Vacuum Unit Heater (D63) described in the permit is 300 mmBtu/hr (see current Carson Operations Title V permit), not 276.92 mmBtu/hr as referenced in the comment (see Section D of the permit, under equipment description). However, the DEIR baseline used to establish emission changes for analyses is 276.92 mmBtu/hr, which is the 98th percentile firing rate of this heater, and is based on near-peak actual operations during the baseline years (see Response G1-79.4). The DEIR baseline is an achieved rate and is less than the permit-described firing rate.

The comment incorrectly references the applicability of condition B61.8 (U.S. EPA NSPS Ja H_2S limit for fuel gas, which does not apply to this heater). This heater combusts exclusively natural gas, which is inherently low in sulfur and, therefore, the heater is not subject to the H_2S limitations of U.S. EPA NSPS Ja (40 CFR Part 60.101).

The comment incorrectly references applicability of permit condition A63.3 which does not apply to the No. 51 Vacuum Unit Heater. While the comment lists permitted emission limits similar to proposed permit condition A63.30, which does apply to the No. 51 Vacuum Unit Heater, the limits listed in the comment vary slightly from the proposed A63.30 limits. Additionally, the comment incorrectly states that "these limits allow greater emissions than were analyzed in the DEIR." The list of allowable pounds per day as calculated in the comment shows the permit limits for all pollutants are less than the post-project emissions listed in the DEIR (e.g., permit CO is 244 lb/day where DEIR CO is 247 lb/day). The proposed post-project emissions limitations listed in the permit (see below) are the same or more stringent than the post-project emissions rates analyzed in the DEIR (see Appendix B-3 on page B-3-49 of the DEIR). In other words, the DEIR conservatively evaluated emissions from this heater at conditions that exceed the limits proposed by the draft Title V permit. Thus no revisions to the Title V permit are necessary. See Response G1-79.4 for a description of the DEIR calculations and the selection of baseline for the heaters.

The SCAQMD has imposed permit conditions that limit emissions, as follows:

Emissions and Requirements: NOx: 2.62 lb/hr; CO: 29.6 lb/MMscf; PM: 6.3 lb/MMscf; ROG: 5.9 lb/MMscf

A63.30 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
ROG	Less than or equal to 48.67 lb per day
CO	Less than or equal to 243.33 lb per day
PM	Less than or equal to 52.14 lb per day

A63.X1 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
NOx	Less than or equal to 94.42 LBS PER DAY

Comment G1-79.11

The proposed permit further allows for greater emissions from the vacuum unit heater than were analyzed in the DEIR because: (1) Condition A99.X1 exempts the 2.62 lbs/hr NOx limit during startup and shutdowns for up to 48 hours; and (2) Condition A195.X1 specifies that the 2.62 lbs/hr limit is based on a 24-hour rolling average. The startup and shutdown exception is problematic for three reasons. First, it could cause violations of the State and federal 1-hour NOx ambient air quality standards.[29] Second, automatic exemptions from permit limits during startup and shutdowns are not permitted.[30] Finally, the DEIR did not evaluate the impact of this exception (i.e., exemptions from hourly NOx limits) on ambient air quality.[31] Therefore, the Air District must eliminate the exception in Condition A99.X1. The 24-hour rolling average is problematic because it allows much higher NOx emissions than assumed in the DEIR. According to Dr. Fox, these higher NOx emissions could cause violations of the State and federal 1-hour NOx ambient air quality standards, and exceed the Air District's 55 lbs/day NOx CEQA significance threshold.[32] G1-79.11

[29] *Id.*
[30] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir. Dec. 19, 2008).
[31] Fox Comments, pp. 6-7.
[32] *Id.*, p. 7.

Response G1-79.11

See Response G1-79.10 that summarizes the permit limitations, including a daily NOx restriction in addition to the rolling 24-hour average that ensures stringent limitation of NOx emissions.

The comment refers to the NOx permit limitation of 2.62 lb/hr (rolling 24-hour average). Hourly NO_2 modeling was not performed at this permit limitation, rather, in order to ensure that modeling was more protective than the 2.62 lb/hr limit, modeling was performed based on a much larger value of 17.49 lb/hr, which is the theoretical maximum hourly emissions value for this heater. The theoretical maximum hourly emissions were calculated based on the physical limitations of the heater, including, the maximum physical firing rate of the heater (360 mmBtu/hr) and an uncontrolled NOx concentration of 40 ppmv[243]. The NOx emissions rate modeled was based on the maximum hourly emissions less the emissions during the baseline period to result in 14.91 lb/hr. Baseline emissions were appropriately subtracted from the worst-case emissions to avoid double counting in subsequent analyses when the modeled results are added to the monitored background NO_2 concentrations (reference FEIR Table 4.2-12). Using the theoretical maximum emission rate as a basis in the ambient air quality modeling, which is much greater than the emissions limit enforced by the permit, represents a worst case scenario which is more protective to the environment. As summarized in FEIR Table 4.2-12, Federal and State NO_2 1-hour standards are not exceeded by the theoretical maximum hourly NOx emissions of this heater.

Contrary to the comment, both U.S. EPA and SCAQMD recognize that it is not possible to meet stringent NOx concentration limitations during startup and shutdown of combustion equipment [EPA letter titled "Re: Vacatur of Startup, Shutdown, and Malfunction (SSM) Exemption (40 CFR 63.6(f)(1) and 63.6(h)(1))" by Adam M. Kushner, Director of the Office of Civil Enforcement, dated July 22, 2009]. However, SCAQMD is imposing startup and shutdown conditions to comply with EPA's startup, shutdown and malfunction requirements. The 24/48-hour limitations included in draft Title V permit condition A99.X1 impose enforceable time limits for startup, shutdown and refractory dry-out occurrences for this heater, thus limiting emissions for this heater. Previously, there was no limitation on startup or shutdown duration. During these startup and shutdown occurrences, NOx emissions are not controlled by pollution control equipment operating at its peak efficiency, but they are not unlimited. The startup and shutdown provision is provided to enable the heater operation to stabilize at a rate where the SCR can be placed in operation without the possibility of damaging the SCR catalyst. If ammonia, which is required for the SCR to function properly, is injected at low temperatures, SCR catalyst damage or plugging and excessive ammonia emissions can occur. Providing

[243] Emissions = (360 mmBtu/hr)(40 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. Daily data from Tables A-2 and A-3 are divided by 24 to obtain hourly values.

shutdown and startup limitations meet EPA's current startup, shutdown and malfunction requirements.

These startup and shutdown events already occur and will not change as a result of the proposed project. No change to ambient air quality would occur. In other words, pre-project startup and shutdown emissions compared to post-project startup and shutdown emissions are the same, resulting in a net emissions increase of zero and do not require further analysis under CEQA. This information is represented in Chapter 4, Table 4.2-4 of the DEIR, as well as Appendix B-3 Table 6 to the DEIR.

Draft permit conditions A99.X1 and A195.X1 would not cause the proposed project to ". . . exceed the Air District's 55 lb/day NOx CEQA significance threshold" for the following reasons: 1) As indicated in Table 79.11-1, the post-project routine NOx emissions evaluated in the DEIR is 94.42 lb/day. The 94.42 lb/day value presented in the DEIR was a preliminary calculation for the post-project emissions, which has since been refined to 62.88 lb/day in the permit application (based on the current PTE of the heater). As shown on Table 4.2-4 on pages 4-16 and 4-17 of the DEIR, the proposed project's overall NOx emission is less than SCAQMD's CEQA significance threshold. Since the NOx emission in the draft Title V permit is limited to 62.88 lb/day, which is lower than the post-project NOx emissions of 94.42 lb/day used in the DEIR, the lower permit limit will not lead to exceedance of SCAQMD's CEQA significance threshold.

Table 79.11-1

Comparison of NO_2 Emissions Presented in the DEIR and Draft Title V Permit Conditions for the No. 51 Vacuum Unit Heater

Emission Rate	Emission (lb/day)
DEIR	94.42
Draft Permit	62.88

2) There is no change in pre-project and post-project startup or shutdown emissions. Any additional startup or shutdown events are speculative.

Comment G1-79.12

B. The Proposed Permit Contains No Limit on SOx in lb/day or lb/MMSCF for the Vacuum Unit Heater

The proposed permit limit for the vacuum unit heater is 162 ppmv of H_2S in the fuel gas, averaged over three hours and excluding any vent gas from emergency malfunction, process upset or relief valve leakage.[33] Dr. Fox explains that "this concentration limit is equivalent to 4.8 lbs/hr of H_2S. When the fuel is combusted, it converts to SO_2. Thus, the proposed limit on H_2S concentration in the fuel gas is equivalent to an SO_2 emission rate limit of 9.6 lb/hr or 230 lb/day."[34] Yet, the DEIR assumes the daily controlled SO_2 emissions from the vacuum unit heater are 4.94 lbs/day[35] and the net increase in SO_2 from the increased firing rate is 1.80 lbs/day.[36] Thus the proposed permit allows greater emissions from the vacuum unit heater than were analyzed in the DEIR. According to Dr. Fox, when the increase in SO_2 allowed from the vacuum unit heater is combined with other Project SO_2 emission increases and decreases (as reported in DEIR Table 4.2-4), the Project SO_2 emissions are 230 lbs/day.[37] This exceeds the Air District's SO_2 significance threshold of 150 lbs/day.[38] Thus, the proposed Title V permit allows a significant air quality impact not disclosed in the DEIR. G1-79.12

[33] Carson Draft Title V Permit, pdf 47.
[34] Fox Comments, p. 8.
[35] DEIR, p. B-3-48.
[36] DEIR, Table 4.3-6.
[37] Fox Comments, p. 7.
[38] *Id.*

Response G1-79.12

As specified in the permit description, the No. 51 Vacuum Unit Heater combusts commercial natural gas, not Refinery fuel gas. The sulfur content of natural gas is very low since it is required to meet pipeline quality by the California Public Utilities Commission (CPUC) and does not require monitoring per EPA Subpart J, Ja, or SCAQMD RECLAIM standards. The comment incorrectly states that the draft heater permit to construct has an H_2S limit of 162 ppmv and the calculations that are referenced in the comment are overstated based on that incorrect H_2S concentration of 162 ppmv. The permit to construct does not have a H_2S limit and neither does the existing Title V permit for this heater. However, the CPUC limits H_2S in natural gas to less than 0.25 grain/100 scf (approximately 4 ppm).[244] The correct projected increased SOx emissions for No. 51 Vacuum Unit Heater, as currently analyzed by the DEIR (1.80 lb/day, see Appendix B-3 on page B-3-49 of the DEIR), do not cause the proposed project to exceed the CEQA SOx significance threshold. As stated in Response G1-79.10, because it combusts natural gas, this heater is not subject to the H_2S limitations of U.S. EPA NSPS Ja and does not require a SOx limit under RECLAIM, but will be limited by the CPUC's pipeline quality requirements. Notably, the SCAQMD permit to construct evaluation for this natural gas fired heater was performed using the same post-project firing rate that was evaluated in the DEIR; ensuring consistency between the two documents and ensuring that the emissions represented in the DEIR are correct.

[244] State of California, Standards for Gas Services in California, December 16, 1992, page 5; Available at: http://docs.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/54827.PDF.

Comment G1-79.13

C. Stack Tests are Insufficient to Ensure Compliance with Emission Limits

The draft permit provides that compliance with the emission limits for PM, ROG, NOx and CO would be determined using an annual stack test.[39] Dr. Fox explains that "annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions."[40] Since CEMS are available for NOx, ROG and CO, Dr. Fox recommends that CEMS be required to determine compliance with the proposed NOx, ROG and CO emission limits.[41] Dr. Fox points out that accurately verifying compliance with the NOx and ROG limits are particularly important because the Air District "is in serious nonattainment with ozone ambient air quality standards."[42]

G1-79.13

G1-79.13 cont'd.

[39] Carson Draft Title V Permit, Condition D29.X1.
[40] Fox Comments, p. 8.
[41] *Id.*
[42] *Id.*

Response G1-79.13

See Response G1-79.9 for a description of the appropriateness of source testing to ensure compliance with criteria pollutant emission limits and the reasons why staging these events is not feasible. Draft permit conditions for this heater are designed to ensure compliance with all applicable rules and regulations. As stated, for NOx emissions monitoring, a CEMS is operated as required by the SCAQMD RECLAIM program. For CO and VOC emissions, periodic source testing satisfies the applicable periodic monitoring requirements of local rules, including SCAQMD Rule 3004(a)(4)(c) periodic monitoring requirements. Process heater stack CEMS availability and why a CEMS is not necessary for CO, VOC, and PM are also explained in Response G-79.9.

Comment G1-79.14

D. The Proposed Permit Allows Emissions from the Refinery Flare No. 5 System (Process 21, System 6) that Are Not Evaluated in the DEIR

The proposed Title V permit adds the Alkylation Unit (Process 9, System 1) to the Refinery No. 5 Flare System.[43] The DEIR does not specifically disclose this addition; it merely mentions that "[p]art of the piping associated with unit modifications may include installation of new pressure relief valves that will tie into the various Refinery flare."[44]

The proposed Title V permit changes the emission limits for this flare system as follows:

- ROG: from 36 lbs/day to 48.7 lbs/day;
- CO: from 21 lbs/day to 243.33 lbs/day; and
- PM: from 106 lbs/day to 52.14 lbs/day.

According to Dr. Fox, the addition of the flare system would also increase NOx and SOx emissions.[45] The proposed permit modifications do not include any limits on NOx or SOx. Further, the DEIR does not include these emission increases.

Dr. Fox provides that the flare system increase in ROG emissions (12.7 lbs/day), when added to other Project increases and decreases in ROG emissions (found in DEIR Table 4.2-4), result in total ROG emissions of 61.8 lbs/day, which exceeds the Air District's ROG significance threshold of 55 lbs/day.[46]

G1-79.14

[43] Draft Carson Title V Permit, pdf 45.
[44] DEIR, p. 2-46.
[45] Fox Comments, p. 9.
[46] *Id.*

Response G1-79.14

The DEIR specifically discloses connection of additional pressure relief valves (PRVs) to the flares in multiple locations as follows: 1) "Part of the piping associated with unit modifications may include installation of new pressure relief valves that will tie into the various Refinery flares. The pressure relief valves allow gases to vent to the flares, which are safety equipment, during emergency or over-pressure situations" (Chapter 2 Sections 2.7.2.1 and 2.7.2.3 through 2.7.2.4 of the DEIR); 2) "PRVs will be routed to the existing Refinery safety flare system, where required, to control VOC emissions in the event of upset conditions in accordance with SCAQMD Rule 1118" (Chapter 4 Section 4.2.2.2.1 of the DEIR); and 3) "The project includes modifications to existing units and new units that will be connected to vapor recovery and safety flare systems. Additional flaring from normal operations is prohibited by SCAQMD Rule 1118. These PRV connections are not expected to increase flaring at the Refinery. 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 Master 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.

There will be no routine vents to the flare system or the flare gas recovery systems from any of the modifications. While the number of pressure relief valves tied in to the flare systems will increase with installation of new or modified process units, this will not cause an increase in flaring. There will, however, be additional potential vent sources to the flare gas recovery and flare systems during unit upsets or emergencies." (See Section 4.3.2.1 of the FEIR.) Nonetheless, SCAQMD Rule 1118 has set emission targets for each refinery which is not altered due to the proposed project.

PRVs are not connected directly to the flare; rather, PRVs are connected to the flare gas recovery system, which is connected to the flare. The flare gas recovery system manages PRV hydrocarbons to its maximum capacity. Once maximum capacity is achieved, the flare, which is in standby mode ready to incinerate excess emissions, is utilized to maintain safety. Connecting PRVs to the flare gas recovery system, instead of allowing them to vent to atmosphere or directly to the flare, is a BACT requirement that also minimizes the need to flare.

The PRV is a safety device that remains closed until its set point pressure is exceeded (i.e., the pressure inside the equipment reaches the set point). More PRV connections to the flare gas recovery system do not increase flaring events, since PRVs are normally closed. PRVs are designed to open only when process operating pressure is significantly above the normal operating pressure. This is a not a frequent occurrence, because refinery processes are designed such that the maximum allowable pressure of the equipment, which sets the pressure at which the PRV opens, is higher than the normal operating pressure.[245]

The comment incorrectly cites the current and proposed ROG, CO and PM emissions limits for the No. 51 Vacuum Unit Heater (see limits shown Response G1-79.10) as the emissions limits for this flare system. No changes to current ROG, CO and PM emissions limits are included in the draft Title V permits or the DEIR as flaring emissions are not expected to increase as a result of the proposed project (see SCAQMD Engineering Evaluation for AN575839 on page 79).

The draft Title V permit does not include ROG, CO, PM NOx, and SOx emission limitations for the No. 5 Flare System as suggested by the comment. As explained above, the proposed project is not expected to result in an increase in flaring emissions.

The Carson Operations Alkylation Unit is one of the units that will be modified with the installation of new pressure relief valves that will be connected to the flare gas recovery system controlled by tie in to the No. 5 Flare System. The installation of additional of fugitive components at the Alkylation Unit will result in approximately 19 lb/day of ROG emissions, a small fraction of which is associated with the addition of a new PRV. These 19 lb/day of ROG emissions are accounted for in Chapter 4, Table 4.2-4, as well as Appendix B-3 Table A-15 to the DEIR.

[245] Introduction to Pressure Relief Valve Design Part 1 – Types and Set Pressure http://smartprocessdesign.com/introduction-pressure-relief-valve-design-part-1-types-set-pressure/.

As explained above, the 12.7 lb/day ROG increase from flaring claimed in the comment is not expected to occur as a result of the proposed project. Therefore, the DEIR accurately evaluated the proposed project impacts and less than significant impacts of VOC emissions are expected.

Comment G1-79.15

E. **The Proposed Permit Fails to Require All Necessary Conditions for the FCCU Shutdown**

The proposed permit requires the shutdown of the FCCU equipment in Condition L341.X1. Dr. Fox points out that the proposed permit fails to include the removal of all supporting fugitive components or, in the alternative, fails to explain how the components would be abandoned in place.[47] Dr. Fox explains that if the components are abandoned in place, the proposed permit must impose conditions that ensure "piping and components are maintained hydrocarbon free, either by blind flanging or by blind flanging and air-gapping."[48] If the permit does not contain these conditions, the DEIR must be revised to eliminate the assumed ROG reductions of 17.6 lbs/day from FCCU fugitive components.[49] If the reductions are eliminated, the total Project VOC emissions would increase to 67 lbs/day, which exceeds the Air District's ROG significance threshold of 55 lbs/day.[50]

G1-79.15

G1-79.15 cont'd.

[47] *Id.*, p. 10.
[48] *Id.*
[49] *Id.*
[50] *Id.*

Response G1-79.15

The operating permit for the Wilmington Operations FCCU will be surrendered and the Unit will be removed from the Wilmington Operations Title V permit. For safety and environmental reasons, the Refinery will ensure that FCCU is hydrocarbon-free as part of its procedures (e.g., evacuating the unit of process fluids and gases, purging the units with steam or another inert gas, monitoring for organics prior to opening to atmosphere, disconnecting fuel lines to combustion sources) to permanently shut down the Unit. In accordance with SCAQMD Rule 203, any stationary source that emits pollutants must have an SCAQMD permit. Therefore, the Refinery must take whatever steps are necessary to ensure there are no emissions from equipment related to the Wilmington Operations FCCU. The SCAQMD will enforce SCAQMD Rule 203 for VOC, CO, and PM, and SCAQMD Rule 2006 for NOx and SOx, to ensure the non-operability of, and lack of emissions from, the Unit including all supporting fugitive components.

Comment G1-79.16

IV. **CONCLUSION**

The Air District cannot issue the proposed Title V permit modifications for the Wilmington and Carson Operations. The proposed modifications for both the Wilmington and Carson Operations are inconsistent with many of the assumptions used in the DEIR to analyze the change in emissions from the Project, allow much higher emission increases of NOx than assumed in the DEIR, and fails to ensure that ambient air quality standards are not exceeded.

G1-79.16

Response G1-79.16

As explained in Responses G1-79.1 through G1-79.14, above, all assumptions and analyses utilized to calculate permitted emission increases from the proposed project are consistent with the DEIR. The analyses in the DEIR correctly calculate emission increases and reductions and conclude that the proposed project does not exceed the SCAQMD's CEQA thresholds. The DEIR also correctly demonstrates that ambient air quality standards are not exceeded as a result of the proposed project. The analysis in the DEIR is correct, but the permits cannot be issued until the CEQA document is certified. Therefore, SCAQMD will rely on the FEIR, when certified, to issue the Title V permit modifications, and ensure those project modifications are fully analyzed.

Comment G1-79.17

Per your request, I have reviewed the proposed Title V significant permit revisions for Tesoro Refining & Marketing Co. LLC, the Wilmington site (Facility ID #800436) and the Carson site (Facility ID #174655). I reviewed the separate draft Title V permit for each facility. As the draft permits do not have any official page numbers, my citations herein are to the pdf page number in each separate document. Thus, the first page of the draft Wilmington Title V permit is pdf 1, etc. and the first page of the draft Carson Title V permit is also pdf 1, etc.

The proposed modifications are based on changes described in the Draft Environmental Impact Report (DEIR) for the Tesoro Los Angeles Refinery Integration and Compliance Project (Project).[1] The specific modifications covered by this revision to the Title V permits represent only a tiny fraction of the changes described in the DEIR. They cover two heaters, Wilmington DCU heater H-100 and Carson No. 51 vacuum heater; the addition of various non-emitting equipment; modifications to the No. 5 Flare System; the shutdown of the Wilmington FCCU; and various fugitive emission sources.

Based on my review, summarized below, many of the proposed modifications allow much higher emissions than assumed in the DEIR.

G1-79.17

[1] Environmental Audit, Inc., Tesoro Los Angeles Refinery Integration and Compliance Project Draft Environmental Impact Report, March 2016. Available at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects.

Response G1-79.17

Response G1-79.2 addresses permit applications that have been submitted to the SCAQMD to support projects represented by the DEIR. The comment also summarizes the conclusions reached in the remainder of the letter. Responses G1-79.18 through G1-79.34 address the issues raised in the letter in detail.

Comment G1-79.18

Relationship to the DEIR

The DEIR evaluated the significance of the Project's operational emissions by calculating the change in daily emissions due to the Project, relative to the CEQA baseline in 2012 to 2013 as follows:[2]

Increase in Emission = Project Emissions (lb/day) – Baseline Emissions (lb/day)

The resulting emission changes for all Project components in pounds per day (lb/day) were compared to the SCAQMD's CEQA significance thresholds. This analysis is summarized in DEIR Table 4.2-4, which concluded that the Project would not result in any significant changes in emissions.

My review of the proposed Title V permit modifications indicates that they fail to assure the emission reductions assumed in the DEIR are achieved in practice and are enforceable.[3] The DEIR deviated from the standard emission increase calculation for heaters that experienced an increase in firing rate. For these heaters, the DEIR used the 98th percentile of the maximum emission rate as the baseline, rather than the daily average emissions in 2012 and 2013. See my DEIR Comment V.C. This artificially inflates the baseline, reducing the emission increases from increases in heater firing rates. The use of an inflated baseline means the emission changes ascribed to the Project are much lower than the actual emission changes that will occur as a result of the Project. The Title V permits must either be modified to assure that the assumed emission reductions are achieved in practice and are enforceable, or the DEIR must be modified to use the correct CEQA baseline and the Title V permit adjusted to ensure they are enforceable. G1-79.18

[2] DEIR, Appx. B-3.

[3] DEIR, Appx. B-3 and Table 4.2-4.

Response G1-79.18

See Response G1-79.4 for a detailed description of the baseline emission calculations and enforceable limits imposed in the draft Title V permit for DCU H-100 heater to ensure that emissions are reduced.

See Response G1-79.15 for a detailed description of how the Wilmington Operations FCCU shutdown emission reductions will be achieved in practice and will be enforced.

Comment G1-79.19

Wilmington Title V Permit Modifications

<u>DCU H-100 Heater Duty Bump</u>

The draft permit includes new conditions for this heater at: A63.XX (PM10, ROG, CO emission limits), A63.YY (NOx, SOx emission limits), A99.X (NOx emission limit startup and shutdown exemption), A195.XX (NOx rolling 24-hr average), A195.YY (SOx rolling 24-hr average), and D29.X (annual stack tests). The changes to the permit are reportedly based on SCAQMD Application 567439. G1-79.19

Response G1-79.19

The comment accurately states the draft Title V permit conditions applied to the Wilmington Operations DCU H-100 heater. The comment is general and does not raise any issues regarding impacts of the proposed project or the draft Title V permit, so no further response is required.

Comment G1-79.20

Daily Criteria Pollutant Emissions

The Project increases the firing rate of heater H-100 by 20%, from the design heat release basis of 252 MMBtu/hr to the maximum heat release basis of 302.4 MMBtu/hr.[4] Increased firing rate increases emissions in direct proportion to the increase. However, the DEIR concluded that the increased firing rate would reduce emissions of all criteria pollutants except SOx by using the wrong baseline as explained in my comments on the DEIR. The emission reductions for heater H-100 claimed in the DEIR are as follows:[5]

- NOx: -171.03 lb/day
- CO: -5.14 lb/day
- PM10: -0.98 lb/day
- PM2.5: -0.98 lb/day
- VOC: -0.43 lb/day
- SOx: 86.69 lb/day

As explained in my comments on the DEIR, this counterintuitive result was obtained by using the 98th percentile of the maximum emissions for baseline emissions. However, this heater does not operate day in and day out at the 98th percentile value. The Title V permit must impose enforceable emission limits to assure that the reductions assumed in the DEIR are achieved in practice or the DEIR must be revised to correct the heater H-100 emission calculations using the correct CEQA baseline. G1-79.20

[4] DEIR, pp. 1-11/12.

[5] DEIR, Table 4.2-4.

Response G1-79.20

See Responses G1-79.4 through G1-79.6 for a detailed description of the emission calculations and enforceable limits imposed in the draft Title V permit for DCU H-100 heater to ensure that emissions are limited, as well as the fact that the applicable SCAQMD CEQA significance threshold is based on “peak daily” emissions rather than average emissions.

Comment G1-79.21

Further, the SCAQMD permit application for the subject modification to heater H-100's firing rate asserts that "Tesoro does not propose to increase the potentials to emit for this heater."[6] However, the proposed daily SOx limit of 250 lb/day and the proposed daily ROG limit of 35 lb/day are much higher than the potential to emit for heater H-100. The SOx PTE is 133 lb/day, compared to the proposed limit of 250 lb/day. The ROG PTE is 27 lb/day,[7] compared to the proposed limit of 35 lb/day. The 8 lb/day difference between the proposed ROG limit and the ROG PTE (35-27=8) is sufficient to tip the total Project ROG emissions of 49.09 lb/day over the CEQA significance threshold of 55 lb/day (49+8=57>55).[8] The DEIR, on the other hand, assumes the H-100 duty bump would reduce VOC emissions. Thus, it is evident that G1-79.21

the proposed Title V permit limits do not assure that the emission assumptions in the DEIR are achieved. G1-79.21 cont'd.

[6] SCAQMD Application 567439, pdf 14.

[7] SCAQMD Application 567439, pdf 14.

[8] Revised ROG emissions 49.09 – 35 – 27 = 57 lb/day, which is greater than 55 lb/day.

Response G1-79.21

See Responses G1-79.4 through G1-79.6 for a detailed description of the emission calculations and enforceable limits imposed in the draft Title V permit for DCU H-100 heater to ensure that emissions are limited.

Comment G1-79.22

Hourly NOx and SOx Limits

Condition S11.X sets an hourly limit on NOx of 18.4 lb/hr and an hourly limit on SOx of 14.08 lb/hr. These hourly emission limits are consistent with emissions used in the criteria pollutant air quality modelling for this heater.[9]

However, subsequent conditions in the draft Wilmington Title V permit weaken these hourly limits by specifying an averaging time that allows exceedances of the 1-hour limits to be averaged out. Condition A195.XX stipulates that compliance with the "hourly" NOx limit is based on a rolling 24-hour average. Condition A195.YY stipulates that compliance with the 1-hour SOx limit is also based on a rolling 24-hour average. This type of averaging convention allows much higher hourly emissions than were assumed in the criteria pollutant modelling, performed to demonstrate compliance with ambient air quality standards.[10] G1-79.22

A rolling 24-hour average smooths out emissions data and eliminates peak hourly values that would otherwise exceed the hourly values used in the air dispersion modeling analysis and limited in Condition S11.X. A rolling 24-hour average works like this. You take the first 24 hourly measurements (which may include values that exceed the hourly permit limit by a significant amount) and you average them all together for the first data point. You then drop out the first hourly value and average the next 24 hourly measurements. You continue in this manner, rolling through the entire data set, 24 hours at a time. If any of these 24-hour averages exceeds the hourly averages in Condition S11.X, it's a violation of the limit. This guts the intent of the 1-hour limit in Condition S11.X, which is essential to assure that hourly average ambient air quality standards are not exceeded.

[9] The air quality modelling assumed: NOx: 2.7761364 g/s and SOx: 1.9145803 g/s. (Files: I&C - 1-8-hr (incl Cogen)_2011_NOX.dta and I&C - 1-8-hr (incl Cogen) 2011_SOX.dta). These are equivalent to (2.7761364 g/s)(60 s/min)(60 min/hr)(0.00220462 lb/g) = **22.03 lb/hr** for NOx and (1.9145803 g/s)(60 s/min)(60 min/hr)(0.00220462 lb/g) = **15.2 lb/hr** for SOx.

[10] DEIR, Table 4.2-12 and Table 10, p. B-3-23.

Response G1-79.22

Responses G1-79.6 and G1-79.7 address the potential ambient air quality issues, including descriptions of why the 1-hour NO_2 and SO_2 NAAQS will not be exceeded.

Comment G1-79.23

This is particularly critical for NOx. The DEIR reported a total 1-hour average NOx concentration of 301.4 ug/m^3, compared to the State 1-hour ambient air quality standard of 339 ug/m^3.[11] The DEIR also reported a total 1-hour average NOx G1-79.23

concentration of 184.9 ug/m^3 compared to the federal 1-hour ambient air quality standard of 188 ug/m^3.[12] These values are very close to the standards. If the modelled NOx concentration increased by just 3.2 ug/m^3,[13] from 38.6 ug/m^3 to 41.8 ug/m^3, the total NOx concentration would exceed the federal 1-hour NOx standard. This is readily foreseeable, given the 24-hour rolling averaging time. Thus, the proposed 24-hour averaging times allows potentially significant unmitigated ambient air quality impacts. G1-79.3 cont'd.

The rolling 24-hour averaging convention may also allow violations of the 1-hour SO_2 State (655 ug/m^3) and federal (196 ug/m^3) ambient air quality standards, especially the federal standard.

Therefore, the 24-hour rolling average conventions in Conditions A195XX and A195.YY should be eliminated.

[11] DEIR. Table 4.2-12.

[12] DEIR. Table 10, p. B-3-23.

[13] 1-hr federal NOx NAAQS – total = 188-184.9 = 3.9 ug/m^3. The modeled 1-hour federal impact is 38.6 ug/m3. Thus, a 10% increase in the 1-hour NOx emission rate would exceed the federal 1-hour NOx NAAQS.

Response G1-79.23

See Response G1-79.6, which clarifies that modeling demonstrated compliance with hourly ambient air quality standards while using worst-case startup and shutdown NOx emissions and worst-case SOx emissions. Since even the worst-case hourly emissions do not cause exceedance of the hourly NAAQS, the 24-hour rolling average permit limits are not improper.

Comment G1-79.24

Exceptions to Hourly NOx and SOx Limits

In addition to the generous averaging convention for hourly NOx and SOx limits, Condition A99.X at pdf 19 sets an exception to the new hourly NOx limit as follows:

The 18.40 lb/hr NOX emission limit(s) shall not apply during the heater startup, shutdowns or refractory dryout periods. For the purpose of this exception, each startup event shall not exceed 48 hours, not including refractory dryout period up to 48 additional hours and each shutown event shall not exceed 24 hours.

This exemption would allow unlimited increases in NOx emissions, sufficient to violate the state and federal 1-hour NOx ambient air quality standards and exceed the 55 lb/day NOx CEQA significance threshold for up to 48 hours at a time. A 10-fold increase, for example, is plausible as the SCR system, which typically reduces 90% of the NOx, would be off-line. This would be sufficient to violate the federal and state 1-hour NOx ambient air quality standards and exceed the CEQA NOx significance threshold.

G1-79.24

Response G1-79.24

The comment repeats a previous comment, see Response G1-79.8.

Comment G1-79.25

The DEIR did not evaluate the impact of exemptions from hourly NOx limits on ambient air quality. This exemption results in a significant impact that was not disclosed in the DEIR. Further, automatic exemptions from permit limits during startups and shutdowns are no longer allowed.[14] The exemption in Condition A99.X should be eliminated.

G1-79.25

G1-79.25 cont'd.

[14] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir., Dec. 19, 2008).

Response G1-79.25

The comment repeats a previous comment, see Response G1-79.8.

Comment G1-79.26

Compliance

Compliance with the emission limits for PM10, ROG, and CO is determined using an annual stack test,[15] while compliance with NOx and SOx limits is based on the use of a SCAQMD-certified continuous emission monitoring system (CEMS). Annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions. As CEMS are available for ROG, CO, and PM, they should be required to determine compliance with the proposed ROG, CO, and PM emission limits. It is particularly important to accurately verify compliance with the ROG limit as the SCAQMD is in serious nonattainment with ozone ambient air quality standards.

[15] Wilmington Draft Title V Permit, pdf 18, Condition A63.XX.

G1-79.26

Response G1-79.26

The comment repeats previous comments, see Responses G1-79.9 and G1-79.13.

Comment G1-79.27

Carson Title V Permit Modifications

Carson No. 51 (D63) Vacuum Unit Heater

The Carson No. 51 Vacuum Unit Heater (D63) will be modified to increase its maximum permitted firing rate from 276.98 MMBtu/hr (98th percentile)[16] to 360 MMBtu/hr.[17] The increase in firing rate will increase emissions. The draft Title V permit sets new limits at A99.X1 (startup and shutdown exemption), A195.X1 (NOx 24 hr average), B61.8 (fuel gas H_2S limit), C1.X1 (heat input limit), and D29.X1 (test methods).

NOx, ROG, CO, and PM Emission Limits

The draft permit sets the following emission limits:[18]

- CO: 29.6 lb/MMSCF natural gas
- PM: 6.3 lbs/MMSCF natural gas
- ROG: 5.9 lbs/MMSCF natural gas
- NOx: 2.62 lbs/day natural gas

G1-79.27

Assuming the maximum firing rate of 360 MMBtu/hr and the higher heating value (HHV) of natural gas of 1050 MMBtu/MMSCF[19], these are equivalent to:

- CO: 244 lbs/day (DEIR:247 lbs/day)
- PM: 52 lbs/day (DEIR: 53 lbs/day)
- ROG: 48 lbs/day (DEIR: 50 lbs/day)
- NOx: 2.62 lbs/day (DEIR: 3.93 lbs/day)

These calculations indicate that the limits in lb/MMSCF natural gas are consistent with emissions assumed in the DEIR and the limits in lbs/day in Condition A63.3.[20] G1-79.27 cont'd.

The DEIR calculated the increase in emissions from the increased firing rate relative to the 98th percentile baseline, which is the wrong CEQA baseline. Thus, these limits allow a higher increase in emissions of these pollutants than assumed in the DEIR. However, it appears that the excess is much smaller than in the case of Wilmington heater H-100. These limits should thus be adjusted down to account for reductions relative to the 2012/2013 average CEQA baseline rather than the 98th percentile baseline.

[16] DEIR, p. B-3-56.

[17] DEIR, p. B-3-49 and Wilmington Draft Title V Permit, Condition C1.X1.

[18] Carson Draft Title V Permit, pdf 1.

[19] DEIR, Appx. B-3, p. B-3-48.

[20] Carson Draft Title V Permit, pdf 46: ROG <48.67 lb/day; CO <243.33 lbs/day; PM <52.14 lb/day.

Response G1-79.27

See Response G1-79.10.

As explained in detail in Response G1-79.4, contrary to the suggestions in the comment, the selection of baseline criteria pollutant emissions for modified heaters using a 98th percentile metric, as opposed to an average emissions metric, is reasonable and supported by substantial evidence. This metric was selected because it was a conservative near-peak measurement based on actual emissions data that correspond with SCAQMD's CEQA significance threshold, which is based on peak daily emissions, and with existing criteria pollutant air quality standards. Therefore, no revisions to the DEIR or draft Title V permit are required.

Comment G1-79.28

However, Condition A99.X1 at pdf 46 exempts the 2.62 lbs/hr NOx limit during startups and shutdowns and allows the exemption to last up to 48 hours. Condition A195.X1 further specifies that the 2.62 lb/hr limit is based on a 24 hour average.

Thus, as explained for Wilmington heater H-100, the exemption and the 24 hour average allow much higher NOx emissions than assumed in the DEIR. These higher NOx emissions could cause violations of the State and federal 1-hour NOx ambient air quality standards as well as exceed the 55 lb/hr NOx significance threshold. G1-79.28

The DEIR did not evaluate the impact of exemptions from hourly NOx limits on ambient air quality or the impact of using a 24-hour average on compliance with the 1-hour NOx standards. Further, automatic exemptions from permit limits during startups and shutdowns are no longer allowed.[21] The exemption in Condition A99.X1 should be eliminated.

[21] *Sierra Club v. Environmental Protection Agency*, 2008 WL 5264663 (D.C. Cir., Dec. 19, 2008).

Response G1-79.28

The comment repeats a previous comment, see Response G1-79.11.

Comment G1-79.29

SOx Emission Limit

The draft Carson Title V permit does not contain a limit on SOx in lb/day or lb/MMSCF. Rather, it sets a limit of 162 ppmv on H_2S in the fuel gas, averaged over 3 hours and excluding any vent gas from emergency malfunction, process upset or relief valve leakage.[22] This concentration limit is equivalent to 4.8 lb/hr[23] of H_2S. When the fuel gas is combusted, the H_2S is converted into SO_2. Thus, the proposed limit on H_2S concentration in the fuel gas is equivalent to an SO_2 emission rate limit of 9.6 lb/hr or 230 lb/day.

The DEIR, on the other hand, assumed the daily controlled SO_2 emissions from this heater are 4.94 lb/day[24] and the net increase in SO_2 due to the increased firing rate are 1.80 lb/day.[25] Thus, the Carson draft Title V permit fails to limit SO_2 emissions to those assumed in the DEIR.

The increase in SO_2 allowed from this single heater, combined with all other Project SO_2 emission increases and decreases as reported in DEIR Table 4.2-4, is 230 lb/day. This exceeds the SO_2 significance threshold of 150 lb/day.[26] Maximum daily SO_2 emissions could be even higher, as the 160 ppm H_2S limit is exempted under certain upset conditions. Thus, the draft Carson Title V Permit allows a significant air quality impact not disclosed in the DEIR. G1-79.29

[22] Draft Carson Title V Permit, pdf 47.

[23] Converting ppm H_2S to lb/hr H_2S: (160 ppm)(34 lb/lb-mole)(360 MMBtu/hr)(1,000,000 scf/MMsfc)/1050 MMBtu/MMscf]/[386.5 ft^3/lb-lb-mole x 10^6 ppm] = **4.83 lb/hr H_2S .**

[24] DEIR, pdf B-3-48.

[25] DEIR, Table 4.3-6.

[26] Total Project SO_2 emissions = <0.01 + 230 = 230 lb/day.

Response G1-79.29

See Response G1-79.12. This heater is only permitted to combust natural gas. Since it cannot combust Refinery fuel gas, it is not subject to the U.S. EPA NSPS J or Ja standard of 162 ppmv H_2S limit. Because it exclusively combusts natural gas (an inherently clean fuel) the emission calculations in the DEIR are correct. As indicated in Response, G1-79.12, natural gas is regulated by the CPUC and has low sulfur content. Therefore, SOx emissions calculations would be predictable and accurate without the use of a CEMS.

Comment G1-79.30

Compliance

Compliance with the emission limits for PM, ROG, NOx, and CO is determined using an annual stack test.[27] Annual stack tests are staged events and are thus not adequate to assure that emission limits are met routinely under all operating conditions. As CEMS are available for NOx, ROG, CO and PM, they should be required to determine compliance with the proposed NOx, ROG, CO, and PM emission limits. It is particularly important to accurately verify compliance with the NOx and ROG limits as

[27] Carson Draft Title V Permit, pdf 48, Condition D29.X1.

G1-79.30

Response G1-79.30

As explained in Responses G1-79.9 and G1-79.13, source tests are not staged events and are appropriately used to ensure compliance with permit limits under all operating conditions. Process heater stack CEMS availability and why a CEMS is not necessary for CO, VOC, and PM are also explained in Responses G-79.9 and G1-79.13.

Comment G1-79.31

The draft Carson Title V permit does not explain how compliance with the H_2S limit will be determined. In fact, it eliminates Condition D90.16, which required monitoring for H_2S, but fails to replace this condition.

The draft Carson Title V permit should be modified to include a SOx limit consistent with DEIR assumptions and should require compliance using a SCAQMD-certified continuous emission monitoring system (CEMS).

G1-79.31

Response G1-79.31

See Response G1-79.12. The comment incorrectly references applicability of condition D90.16 which requires the periodic monitoring of H_2S under U.S. EPA NSPS J provisions. This heater is not subject to the U.S. EPA NSPS J or Ja 162 ppmv H_2S limit as it exclusively combusts natural gas (an inherently clean fuel). Natural gas is regulated by the CPUC and has consistent sulfur content. Therefore, SOx emissions calculations would be predictable and accurate without the use of a CEMS.

Comment G1-79.32

Refinery Flare No. 5 System (Process 21, System 6)

The draft Carson Title V permit adds the Alkylation Unit (Process 9, System 1) to the Refinery No. 5 Flare System.[28] This addition is not specifically disclosed in the DEIR, beyond a general mention that "[p]art of the piping associated with unit modifications may include installation of new pressure relief values that will tie into the various Refinery flare."[29] The emission limits for this flare system are changed as follows:

- ROG: from 36 lb/day to 48.7 lb/day
- CO: from 21 lb/day to 243.33 lb/day
- PM: from 106 lb/day to 52.14 lb/day

The addition of the Alkylation Unit to the No. 5 Flare System would also increase NOx and SOx emissions, but the proposed permit modifications do not include any limits on NOx or SOx.

These emissions changes are not included in the DEIR. The increase in ROG emissions, 12.7 lb/day, when added to other Project increases and decreases in DEIR Table 4.2-4, results in total ROG emissions of 61.8 lb/day, which exceeds the ROG significance threshold of 55 lb/day. Further, the draft Carson Title V permit fails to set emission limits for this flare system on NOx or SOx or to include any compliance monitoring. The proposed reduction in PM emissions is unsupported and inconsistent with adding the Alkylation Unit to the No. 5 Flare System. G1-79.32

[28] Draft Carson Title V Permit, pdf 45.

[29] DEIR, p. 2-46.

Response G1-79.32

The specified ROG, CO, and PM limits do not apply to No. 5 Flare System, nor are there any emission changes in the draft Title V permit. Adding the PRVs from the Alkylation Unit to the flare has a small increase in fugitive component VOC emissions only (see Response G1-79.14).

Comment G1-79.33

FCCU Shutdown

The draft Carson Title V permit requires the shutdown of FCCU equipment in Condition L341.X1. This equipment list is incomplete. The DEIR also took credit for 17.6 lb/day of ROG emission reductions from FCCU fugitive components.[30]

The draft Carson Title V permit should be modified to require the removal of all supporting fugitive components in this condition or explain how it will be abandoned in place. If the latter, conditions must be imposed to assure piping and components are maintained hydrocarbon free, either by blind flanging or blind flanging and air-gapping.[31] Otherwise, the ROG reductions assumed in the DEIR should be eliminated. The elimination of these ROG reductions would increase total Project VOC emissions to 67 lb/day (49.09+17.6=66.69), which exceeds the ROG significance threshold of 55 lb/day. G1-79.33

[30] DEIR, Table 4.2-4.

[31] See SCAQMD Application 567649, pdf 512.

Response G1-79.33

The comment repeats a previous comment, see Response G1-79.15.