RESPONSE TO COMMENT LETTER 1

Adams and Broadwell Letter and Attachment A Responses to Comments
November 13, 2014

Response 1-1

The commenter states that they are writing comments on the 2014 Draft Environmental Impact Report (EIR) for the Phillips 66 Ultra Low Sulfur Diesel (ULSD) project on behalf of the Safe Fuel and Energy Resources California. This comment does not address the analysis of the ULSD Project in the 2014 Draft EIR so no further response is necessary. The comment also notes that the South Coast AQMD prepared the CEQA document pursuant to the CEQA statutes and provides a brief summary of the ULSD Project description. These comments are generally accurate and no further response is necessary.

Response 1-2

This comment notes that a previous CEQA document was prepared for the ULSD Project and that the California Supreme Court struck down the South Coast AQMD's methodology for establishing the baseline and ordered the South Coast AQMD to prepare an EIR. The 2014 Draft EIR fully addresses the holding in *CBE v. SCAQMD*. With regard to how the baseline for the ULSD Project was developed, refer to 2014 Draft EIR pages 3-1 and 3-2 and Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-49, 1-50, 1-53, 1-69, and 1-73.

Response 1-3

The 2014 Draft EIR for the ULSD Project fully addresses the holding in *CBE v. SCAQMD*. The California Supreme Court held that the Negative Declaration improperly used the maximum permitted activity as the baseline. The Supreme Court also found that there was a fair argument that the ULSD Project may result in significant impacts related to air emissions during operations, and so remanded for preparation of an EIR. In so doing, however, the Supreme Court did not conclude that the project would result in any significant impact. It left that determination to the South Coast AQMD, based on substantial evidence following preparation of an EIR. The South Coast AQMD has now prepared an EIR using actual conditions rather than permitted maximum activity levels as the baseline.

In addition to the holdings, the Supreme Court's discussion also guided the preparation of the EIR. The Supreme Court noted statements of the South Coast AQMD and Phillips 66 that refinery operations are complex and variable. 48 Cal. 4th at 327. The Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence. 48 Cal. 4th at 327-28. The Supreme Court also stated that, in preparing the EIR, the South Coast AQMD is not required to use the same measurement method as used in the Negative Declaration. 48 Cal. 4th at 328. Thus, the South Coast AQMD believes the Draft EIR is consistent with the Court decision.

The 2004/2005 CEQA documents (which included a Negative Declaration, Addendum, and Subsequent Negative Declaration) did not closely examine the details of the design or operation of the refinery's steam generation system because in no event would the activity and emissions exceed the permitted maximum levels being used as the baseline for the boilers and cogeneration system. In other words, with the baseline used in the 2004/2005 CEQA documents, the steam required for the project would not result in a net emissions increase from the boilers and cogeneration system. In Response to Comments on those documents, the South Coast AQMD made a theoretical calculation assuming the steam needed for the project would be met by Boiler 4 using a "worst-case" assumption that all other boilers would be down for maintenance. This was considered to be a "worst-case" analysis because Boiler 4 is the oldest boiler with the highest emissions. The Supreme Court characterized the use of the permitted maximum allowable use of the boiler as a hypothetical baseline. The Negative Declaration described the emissions estimate associated with the Boiler 4 as theoretical. The South Coast AQMD did not use either of these assumptions to develop the baseline in the 2014 Draft EIR.

The 2014 Draft EIR no longer uses either the permitted maximum levels as baseline, or the worst case assumption and theoretical calculation regarding the source of the steam required for the project. Rather, the analysis in the Draft EIR is grounded in facts regarding the design and operation of the refinery's existing steam generation system. As stated on page 3-1 of the 2014 Draft EIR, the 2002-2003 time period is considered to be the pre-ULSD Project baseline conditions for Refinery operations as this represents the timeframe during the environmental analysis development for the ULSD Project and was prior to the construction and operation of the ULSD Project. The baseline used in the EIR was the actual refinery emissions in the 2002-2003 timeframe. Therefore, the EIR used actual data to determine the baseline emissions, which constitutes substantial evidence, as directed by the Supreme Court.

Many of the comments (such as errors in the project emissions resulting in significant air quality impacts) from this comment through comment 1-37 paraphrase more detailed comments contained in Attachment A of this Comment Letter 1. Therefore, where a comment paraphrases a detailed comment made in Attachment A of Comment Letter 1, the reader will be referred to the appropriate Responses to Comments in Attachment A. Otherwise, responses have been prepared below for unique comments that do not appear in Attachment A.

<u>Response 1-4</u>

The comment identifies some of the advocacy positions of SAFER. Since the advocacy positions of the commenter do not specifically comment on the proposed project or the environmental analysis in the Draft EIR, no further response is necessary.

<u>Response 1-5</u>

Most of this comment discusses advocacy positions and issues of concern to SAFER, but does not comment on the proposed project or the environmental analysis in the Draft EIR. Refineries produce and use hazardous materials as part of their operations. Toxic substances handled by Phillips 66 include hydrogen sulfide; ammonia; regulated flammables such as propane and butane; and petroleum products, such as gasoline, fuel oils and diesel. However, as discussed in the 2004/2005 CEQA documents for the proposed project, refineries are highly regulated. A variety of safety laws and regulations have been established to reduce the risk of accidental releases of chemicals at industrial facilities, including refineries. Such regulations include the following: The Occupational Safety and Health Administration's Process Safety Management of Highly Hazardous Chemicals, 29 Code of Federal Regulations, 910.119; Federal EPA Risk Management Program; the California Accidental Release Program (CalARP); the California Health and Safety Code Fire Protection specifications; and applicable Cal-OSHA requirements. In addition, a variety of design standards apply to refineries including: the design standards for petroleum refinery equipment established by the American Petroleum Institute; American Society of Mechanical Engineers; the American Institute of Chemical Engineers; the American National Standards Institute; and the American Society of Testing and Materials.

It should be noted that the refinery has operated consistently for more than ten years following completion of the project without any evidence that the equipment associated with the ULSD project has caused harm to the environment, worker health, the surrounding community or the local economy, and the comment letter provides no evidence of such harm. In addition, with the exception of the emissions baseline, the Supreme Court did not identify any other issues regarding the adequacy of the environmental review of the ULSD Project. CEQA analysis for the ULSD Project was initially completed in 2004 and 2005 with the approval of the Negative Declaration, Addendum and Subsequent Negative Declaration. Further, any issue not raised in a petition for writ of mandate challenging the 2004/2005 approvals is foreclosed by the statute of limitations. Pub. Res. Code § 21167. Finally, some of the topics mentioned in the comment were raised in timely petitions for writ of mandate filed in 2004 and 2005, but were rejected by the Superior Court or the Court of Appeal. Therefore, this EIR is limited to the single issue for which the Supreme Court ordered remand.

Regardless, hazardous materials and hazardous processes (including the risk of injury or death and catastrophic events) were evaluated in the 2004 ND at pages 2-27 through 2-31; Appendix B; and Response 1-5 on page C-29 in Appendix C. Hazardous materials and hazardous processes (including the risk of injury or death and catastrophic events) were evaluated in the 2005 Supplemental Negative Declaration (SND) at pages 2-23 to 2-33 and Appendix B. In Superior Court Case No. BS091276, the commenter challenged the adequacy of the analysis with respect to exposure of commenters and construction workers to high levels of toxic chemicals during site excavation and earthmoving activities, and exposing commenters, construction workers and nearby residents to increased risk of exposure to aqueous and anhydrous ammonia from the increased transportation to the Wilmington Refinery, and use and storage at the Wilmington Refinery of aqueous and anhydrous ammonia. See, e.g., Fourth Amended Petition for Writ of Mandate, paragraphs 7.b., 7.f., 68.d, 69, 85.c. through 85.e., 97-104, 114.d., 164.a., 205.c. through 205.f., and 212-217 at pages 3-4, 14-15, 17, 19, 21, 28, and 35-37. The Superior Court rejected the commenter's argument that the hazards analysis was deficient. See Order Denying Motions for Peremptory Writ of Mandate and Statement of Decision filed August 1, 2005, pages 22-24; and Order Denying Petition for Peremptory Writ of Mandate and Statement of Decision filed June 12, 2006, pages 14-22. The commenter opted not to seek appellate review of the Superior Court's decision on this topic. Accordingly, the decision of the Superior Court is *res judicata* with respect to the hazards issues litigated. The commenter had the opportunity to challenge other aspects of the hazards analysis in that litigation, and did not do so. It is now too late to raise new issues related to hazards.

Health and safety hazards were discussed in the 2004 Negative Declaration (ND): at pages 2-11 to 2-12 for exposure to air toxics; pages 2-28 to 2-29 and Appendix B for exposure to hazards and hazardous materials, etc.; page 2-41 for exposure to noise during construction; page 2-50 for exposure to traffic hazards; and Response 1-33 on pages C-56 to C-57 for worker safety. In the 2005 SND health and safety hazards were discussed: at pages 2-13 and 2-14 for exposure to air toxics; at pages 2-25 to 2-28 and Appendix B for exposure to hazards and hazardous materials, etc.; at pages 2-28 to 2-30 for hazards during transportation; page 2-26 for worker exposure to soil contamination and Response 1-19 on page C-30 of Appendix C; page 2-49 for exposure to traffic hazards. In Superior Court Case No. BS091276, in addition to the impacts described above with respect to hazards, the commenter asserted that the CEQA documents failed to adequately analyze potential impacts with respect to increased cancer risk. See Fourth Amended Petition for Writ of Mandate, paragraph 164.c., page 28. Except as noted, the commenter opted not to press its other challenges and/or to seek appellate review of the Superior Court's decision. Accordingly, the prior CEQA documents are final and the decision of the Superior Court is *res judicata* with respect to all these health and safety issues. The commenter had the opportunity to challenge other aspects of the safety analysis in that litigation, and did not do so. It is now too late to raise new issues related to safety.

Potential odor nuisance impacts were evaluated in the 2004 ND at pages 2-14 and 2-15 and Response 2-3 on page C-75 in Appendix C and in the 2005 SND at page 2-15. In Superior Court Case No. BS091276 the commenter did not raise any issues related to odors or other nuisance impacts. The commenter had the opportunity to challenge the adequacy of the nuisance analysis in that litigation, and did not do so. It is now too late to raise new issues related to odors or other nuisance.

Potential impacts to public services and infrastructure were evaluated in the 2004 ND at pages 2-42 and 2-43 and in the 2005 SND at pages 2-44 and 2-45. In Superior Court Case No. BS091276, the commenter did not raise any issues related to impacts to public services and infrastructure. The commenter had the opportunity in that litigation to challenge the adequacy of the analysis of impacts to public services and infrastructure, and did not do so. It is now too late to raise new issues related to impacts to public services and infrastructure.

The last paragraph of this comment asserts that members of SAFER would be directly affected by the proposed project's adverse environmental impacts. The Draft EIR is limited to the issue determined by the Supreme Court to have been analyzed incorrectly in the 2004/2005 CEQA documents. Specifically, the EIR changes the baseline for the air quality analysis from the maximum permitted level of activity to the actual conditions. This change affects the analysis of criteria pollutants and toxic air contaminants. Other topics raised in the comment have already been determined to be adequate, as explained above.

This comment generically mentions the economic wellbeing of workers and the community; work stoppages; future jobs; and "employment and economic benefits to local workers and communities." It should be noted that these are socioeconomic impacts. Under CEQA, socioeconomic impacts are not considered environmental impacts unless they in turn cause a physical change in the environment that is a significant adverse effect. Pub. Res. Code § 21082.2 (c); CEQA Guidelines §§ 15064 (e) and 15382. No comments on the 2004/2005 CEQA documents asserted that the ULSD Project would cause socioeconomic impacts that would, in turn, cause significant environmental impacts, and this issue was not raised in the lawsuits timely filed that challenged the adequacy of those CEQA documents. Finally, while this document evaluated potential environmental impacts from the project, issues such as onsite worker safety are regulated by existing Cal OSHA requirements, inspections, protocols, etc.

Response 1-6

In this comment, excerpts of CEQA law are cited, but they are incomplete. For example, Public Resources Code Section 21082.2 (c) states: "Argument, speculation, unsubstantiated opinion or narrative, evidence which is clearly inaccurate or erroneous, or evidence of social or economic impacts which do not contribute to, or are not caused by, physical impacts on the environment, is not substantial evidence. Substantial evidence shall include facts, reasonable assumptions predicated upon facts, and expert opinion supported by facts." The South Coast AQMD considered CEQA and the CEQA Guidelines in their entirety in preparing the Draft EIR for the ULSD Project, which complies with all relevant provisions of CEQA. A discussion of the existing or baseline physical environmental conditions in the vicinity of the ULSD Project was presented in the Draft EIR in accordance with CEQA law and guidelines (see Draft EIR, Section 3.2 – Air Quality Setting, pages 3-2 through 3-25). The commenter does not provide any evidence to the contrary. See Responses to Comments 1-7 through 1-12 for more details regarding baseline.

Response 1-7

The comment cites excerpts from *CBE v. SCAQMD*, but they are only excerpts.

As stated on page 3-1 of the Draft EIR, the 2002-2003 time period is considered to be the pre-ULSD Project baseline conditions for Refinery operations as this represents the actual timeframe during the environmental analysis development for the ULSD Project and was prior to the construction and operation of the ULSD Project. Therefore, the baseline used in the EIR was the **actual**, not hypothetical, refinery emissions in the 2002-2003 timeframe, as shown in Table 1 below (see Response 1-9). These facts constitute substantial evidence, as directed by the Supreme Court. See Response 1-3 for a more detailed response. The South Coast AQMD considered the entirety of the Supreme Court's decision in preparing the EIR for the ULSD Project. The Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence: "We do not attempt here to answer any technical questions as to how existing refinery operations should be measured for baseline purposes in this case or how similar baseline conditions should be measured in future cases… Neither CEQA nor the CEQA Guidelines mandates a uniform, inflexible rule for determination of the existing conditions baseline. Rather, an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." 48 Cal. 4th at 327, 328. The Supreme Court also stated that, in preparing the EIR, the South Coast AQMD is not required to use the same measurement method as used in the Negative Declaration: "The District is not necessarily required to use the same measurement method in the EIR as in the Negative Declaration. Whatever method the District uses, however, the comparison must be between existing physical conditions without the [ULSD] Project and the conditions expected to be produced by the project." 48 Cal. 4th at 328. The Draft EIR does not use either the permitted maximum levels as baseline, or the worst case assumption and theoretical calculation regarding the source of the steam required for the project that were used in the 2004/2005 CEQA documents. Comment 1-7 incorrectly asserts that the Draft EIR uses a hypothetical baseline. As stated on page 3-1 of the Draft EIR, the 2002-2003 time period is considered to be the pre-ULSD Project baseline conditions for Refinery operations as this represents the **actual** timeframe during the environmental analysis development for the ULSD Project and was prior to the construction and operation of the ULSD Project. Therefore, the baseline used in the EIR was the actual refinery emissions in the 2002-2003 timeframe. These facts constitute substantial evidence, as directed by the Supreme Court and CEQA regulations and Guidelines.

Response 1-8

The comment misrepresents the holding in *San Joaquin Raptor Rescue Center v. County of Merced* (2007) 149 Cal.App. 4th 645. The fundamental problem identified by the court in that case was the EIR's inconsistent and confusing project description. The EIR stated on the one hand that there would be no substantial increase in production, but it presented production volumes that contradicted this statement. The volumes stated for post-project production were greater than pre-project production on every measure, including annual average production (240,000 tons pre-project versus 260,000 tons post-project) and peak annual production (312,890 tons pre-project versus 500,000 or 550,000 tons post-project). The court found that "the Project description set forth in the DRAFT EIR is unstable and misleading because it indicates, on the one hand, that no increases in mine production are being sought, while on the other hand, it provides for substantial increases in mine production if the Project is approved." *Id.* at 655.

The comment asserts that "the court found the 240,000 annual average of the four years preceding the environmental review was the correct baseline." This is not correct. The lead agency – not the court – determined in the first instance that the four year annual average was an appropriate baseline for that project. The court reviewed the lead agency's decision and found that it was supported by substantial evidence, rejecting lower baseline production rates advocated by the petitioners. The court stated: "Since established usage of the property may be considered to be part of the environmental setting … and such usage was adequately shown by the annual production averages, we believe there is substantial evidence in the record to support the County's use of 240,000 tons per year as a baseline for existing conditions…." 149 Cal.App. 4th at 659, citing *Fairview Neighbors v. County of Ventura,* (1999) 70 Cal.App.4th 238. This is consistent with the Supreme Court's holding in *CBE v. SCAQMD* that "an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." 48 Cal. 4th at 328. Contrary to the suggestion in the comment, the *San Joaquin Raptor Rescue* court never discussed whether a baseline based on a peak production level (or a longer or shorter averaging period) would have been acceptable for the project involved in that case, although it favorably mentioned the ruling in *Fairview Neighbors v. County of Ventura* (1999) 70 Cal.App.4th 1170, which did approve use of a baseline that reflected peak production. Consistent with *CBE v. SCAQMD*, the *San Joaquin Raptor Rescue* court reviewed the baseline only to determine if there was substantial evidence to support the four year annual average baseline selected by the lead agency for that project.

Response 1-9

The comment asserts that the Draft EIR's environmental setting or baseline is inadequate because it uses peak emissions rather than "average emissions levels that reflect the actual baseline over a two-year period." The comment claims that use of peak emissions in the baseline inflated the baseline and minimized the impacts of the project. The commenter is mistaken regarding the baseline selected and its effect on the air quality analysis.

The analysis in the Draft EIR does not inflate the baseline, nor does it minimize the impacts. For detailed Responses on Comments related to the baseline (pre-project emissions) for the proposed ULSD Project, refer to the Draft EIR at pages 3-1 and 3-2 and Responses 1-3, 1-7, 1-10, 1-48, 1-50, 1-62, 1-69, 1-71, 1-73, and 1-78.

The Draft EIR presents a wide range of information regarding the environmental setting for air quality. For example, the recent background air quality data presented in Table 3.1-2 of the 2014 Draft EIR includes information regarding actual air quality based on short-term measurements of one hour or 8 hours, and also includes 24 hour and annual averages from 2001 through 2012. This information allows the reader to fully understand the environmental setting during the 2002-2003 baseline period, as well as air quality trends over time.

As mentioned in Response 1-7, the Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence: "We do not attempt here to answer any technical questions as to how existing refinery operations should be measured for baseline purposes in this case or how similar baseline conditions should be measured in future cases… Neither CEQA nor the CEQA Guidelines mandates a uniform, inflexible rule for determination of the existing conditions baseline. Rather, an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." 48 Cal. 4th at 327, 328.

With respect to the existing Refinery's contribution to the ambient air quality, Table 3.1-3 of the 2014 Draft EIR presents the reported annual emissions (tons per year) from the Refinery from 2000 through 2013. Again, this allows the reader to see the Refinery's total contribution in any year as well as to see changes or trends over time for the Refinery as a whole.

The Draft EIR uses a baseline period of two years preceding the commencement of environmental review (years 2002-2003). Using a longer baseline period may be appropriate for some projects. For the Phillips 66 ULSD Project, however, the baseline and the post project periods for comparison were selected to avoid other events and refinery changes that would have obscured the emissions consequences of the project. As noted in *CBE v. SCAQMD*, refinery operations are highly complex and variable. 48 Cal. 4th at 327. To identify the effects of the ULSD Project, it was necessary for the South Coast AQMD to compare baseline and post-project periods that were not influenced by other, independent changes at the refinery. In particular, in November 2001, flue gas recirculation was added to Boiler 7, reducing NOx emissions from about 85 ppm to about 46 ppm (a 46 percent reduction, based on RECLAIM data). If a longer pre-project period were used for the baseline, the baseline emissions would appear to be substantially higher because the baseline would have included many months when Boiler 7 was operating without the added controls. Selective Catalytic Reduction (SCR) was added in December 2008, reducing NOx from 46 ppm to 11 ppm (an 82 percent reduction). If a longer post-project period were used, the post-project period would appear to have substantially lower emissions because it would include many months of operation of Boiler 7 at very low emissions rates due to the SCR unit. The combined effect of using a higher baseline and lower post-project emissions would be to shrink the emissions attributed to the project. The baseline pre-project and post-project periods were chosen to avoid the change in NOx emissions due to these two refinery modifications, which were unrelated to the ULSD Project. To avoid inappropriate influences from these and other independent projects, the South Coast AQMD selected an approximately two-year period for the pre-project baseline and the post-project period.

Data availability also was a consideration in selecting the baseline and post-project periods for comparison. See Draft EIR at p. 3-2. In addition, refinery emissions can be affected by major unit turnarounds.[1] Therefore, to compare comparable operating scenarios, it was important to confirm that the same major unit turnarounds occurred in both the baseline and the post-project periods. Both periods included a turnaround of the Fluid Catalytic Cracking Unit, in 2002 and 2008.

The comment suggests that the Supreme Court held in *CBE v. SCAQMD* that CEQA prohibits use of peak emissions for the baseline. *CBE v. SCAQMD* did no such thing. The case disallowed the use of a baseline based on the maximum level of activity or emissions allowed in a permit, where the simultaneous peak operation of multiple pieces of equipment had not occurred. Indeed, the Court expressly stated that peak impacts may be as important as averages: "[T]he date for establishing baseline cannot be a rigid one. Environmental conditions may vary from year to year and in some cases it is necessary to consider conditions over a range of time periods. In some circumstances, peak impacts or recurring periods of resource scarcity may be as important environmentally as average conditions." 48 Cal.4th at 328. The South Coast AQMD has carefully considered the entirety of the Supreme Court opinion in determining the appropriate baseline for the ULSD Project.

The comment also asserts that it is "illegal under CEQA" to use peak emissions for the baseline, rather than an average or a minimum day. The comment cites no authority to support this assertion, and none exists. For the same reasons discussed above, this assertion is simply wrong.

[1] Note that during refinery turnarounds, processing units are shut down for routine maintenance activities.

The Draft EIR used peak daily emissions levels as the baseline, rather than an average of daily emissions, to be consistent with the U.S. EPA's approach to the National Ambient Air Quality Standards ("NAAQS") and the South Coast AQMD's own long-standing significance thresholds. Most of the NAAQS essentially define air quality based on the "worst day." That is, each NAAQS sets forth a maximum allowable concentration of a pollutant in the ambient air, averaged over a specific period (40 C.F.R. Part 50). The U.S. EPA sets each NAAQS based on extensive and detailed assessments of the health risks associated with exposure to a specific pollutant. Most of the NAAQS have an averaging time of 24 hours or less because adverse health effects generally result from short-term exposures. The South Coast AQMD's baseline is consistent with the NAAQS generally because it measures baseline air quality by the daily peaks – the "worst days" – rather than average emissions levels over a long period of time.

To take just one example, the 1-hour NAAQS for nitrogen dioxide is 100 parts per billion ("ppb") (75 Fed.Reg. 6474 (Feb. 9, 2010)). The U.S. EPA found that this standard was necessary to prevent respiratory health effects resulting from short-term exposures of no more than 1 hour (Id. at p. 6502). This conclusion was based on, among other things, research showing correlations between ambient nitrogen dioxide levels and emergency room visits by asthmatics and other persons at risk for respiratory ailments (Id. at pp. 6479-82).

The peak baseline is also consistent with the South Coast AQMD's significance thresholds. Under the South Coast AQMD's significance thresholds, a project's emissions are considered significant if they exceed a specified amount, measured in pounds, on any given day. The purpose of the thresholds is to measure whether the project will make it more likely for a NAAQS exceedance to occur, as compared to conditions in the baseline. Since the NAAQS, in effect, measure air quality impacts based on a "worst-day" (or shorter period) emissions, the South Coast AQMD similarly evaluates a project's worst day of emissions. The South Coast AQMD chose the peak baseline here because the South Coast AQMD determined that comparing peak to peak emissions is a more accurate measure of a project's true impacts than comparing average to peak emissions. A peak-to-peak comparison, essentially, involves a comparison of apples to apples. An average-to-peak comparison, however does not.

The comment claims that the Draft EIR uses different baselines for different emissions sources. In fact, the appropriate baseline has been used for each source. For example, the baseline emissions data were based on actual peak daily emissions for Heater B-201, while emissions were assumed to be zero for existing Storage Tank 331 because it was not in service during the baseline period. Table 1 summarizes the baseline emission data, methodologies and assumptions used in the EIR. With regard to the pre-project baseline for all components of the ULSD Project, refer to Responses 1-3, 1-7, 1-10, 1-48, 1-50, 1-62, 1-69, 1-71, 1-73, and 1-78.

TABLE 1

BASELINE

Emissions	Data, Methodologies and Assumptions
Fugitive Emissions	The fugitive components added by the Project did not exist in the pre-Project; therefore baseline fugitive emissions for these components were zero.
Heater B-201 (Baseline only)	Continuous Emissions Monitoring Systems data were reviewed to identify peak daily actual emissions during 2002-2003 for comparison to the peak (maximum allowable) emissions in the post-Project period.
Replacement Heater B-401	Heater was built as part of the ULSD Project; therefore, baseline emissions were zero because the heater did not exist in the pre-project period.
Hydrogen Production	Records of combined actual hydrogen use in Units 89 and 90 during 2002-2003 were reviewed. Average daily usage was included in the Draft EIR, and peak actual daily usage has been added to the Final EIR. For information, the Final EIR also identifies the peak actual daily usage for periods when Unit 90 was operating and Unit 89 was not; this data was not used as the baseline because it would result in allocating a smaller emissions increase to the project, which would not be as conservative as the emissions used in the EIR.
Electricity	The electric equipment added by the project (new pumps, fans, air coolers) did not exist in the pre-project period; therefore, baseline electrical demand (and associated emissions) for this equipment was zero. The Unit 89 recycle gas compressor, reactivated as part of the project, existed but was not operating during the pre-project period, and so the baseline electrical demand (and associated emissions) for this equipment was zero. In addition, for the Sulfur Recovery Plant, historical data were used to identify the relationship between electricity demand and sulfur processed (kW-hr per pound of H_2S processed).
Vehicle Emissions	The increase in emissions associated with an increase in mobile sources was included as part of the project. Therefore, baseline vehicle emissions were zero.
Storage Tank 331	The tank was not in service during 2002-2003; therefore, there were no baseline emissions from this tank.
Steam Demand	Actual historical steam production data and throughput data were used to calculate a Refinery-wide value of steam per 1,000 barrels of feed. Engineering review of steam generating and distribution system, and review of data from the steam letdown valve, confirmed that the system consistently generated excess steam from the 400 pounds per square inch (psi) steam system that was vented through the let-down valve to the 150 psi steam header.[2] In addition, for the Sulfur Recovery Plant, historical data were used to identify the relationship between steam demand and sulfur processed (pounds of steam per pound of H_2S processed).

Response 1-10

The comment states that the 2002-2003 baseline selected may be reasonable, but that the Draft EIR included insufficient explanation and data to show that this period was representative. See Draft EIR pages 3-1 and 3-2 and Responses 1-3, 1-7, 1-9, 1-47, 1-50, 1-53, 1-69, and 1-73 for information explaining the selection of the baseline period. The baseline was selected to ensure that the analysis of the impacts of the ULSD Project was not affected by other, independent projects that reduced refinery emissions (see Response 1-9). In addition, the comment speculates

[2] See Figure 3-1 of the EIR for a visual diagram of the Phillips 66 Wilmington Plant steam system.

that in some cases an applicant may temporarily increase operations artificially to establish a higher baseline. The comment presents no evidence that this is the case for the ULSD Project. Table 3.1-3 of the 2014 Draft EIR shows Reported Criteria Pollutant Emissions from the refinery from 2000 through 2013. The emissions data varies from year to year, but it does not show any artificial jump in 2002-2003.

Response 1-11

Comment 1-11 summarizes comments made in Attachment A of Comment Letter 1 that the 2014 Draft EIR does not include any information used to select the years 2002 to 2003 as the pre-project (baseline) for the ULSD Project. This comment is not correct. On pages 3-1 and 3-2 of the 2014 Draft EIR there is a robust discussion of the rationale for why the years 2002 to 2003 were chosen as the pre-project period. For additional detailed information regarding establishing the baseline for the ULSD Project, refer to Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, 1-73. With regard to establishing pre-project emissions specifically from Heater B-201, refer to Response 1-69. Based on the information in these responses in addition to the information provided in the 2014 Draft EIR, substantial evidence is provided to support using the years 2002 and 2003 as the pre-project period. The comment again speculates that in some cases an applicant may temporarily increase operations artificially to establish a higher baseline. As noted in Responses 1-9 and 1-10, the commenter presents no evidence that this is the case for the ULSD Project. Table 3.1-3 of the 2014 Draft EIR shows emissions data, which varies from year to year, but it does not show any artificial jump in 2002-2003.

Comment 1-11 also summarizes a comment made in Attachment A of the Comment Letter 1 that the 2014 Draft EIR reports emissions for the Refinery for the period 2000 to 2013 (2014 Draft EIR, Table 3.1-3), but these summaries do not provide support for the pre-project years 2002 to 2003. This assertion shows a misunderstanding of the information in Table 3.1-3 of the 2014 Draft EIR. The Refinery's actual reported emissions data from 2000 to 2013 is presented (1) in the interest of maximum disclosure, (2) as an aspect of the environmental setting, and (3) so that the reader and decision-maker can discern trends. With respect to the contribution from the Heater B-201 to the environmental setting, the South Coast AQMD reviewed complete NOx and SOx data for 2002 and 2003 from the continuous emissions monitoring system. These data include hourly emissions totals which can then be used to calculate actual emissions for other time periods such as daily or annual. Here, actual daily emissions for Heater B-201 were used as the baseline for comparison to Project emissions from the new Heater B-401 because the relevant mass-based significance thresholds are stated in pounds per day of emissions. Attachment 1 to these Response to Comments provides the 2002 and 2003 RECLAIM data used to determine the baseline. The fuel use on the day with the highest NOx and SOx data was used to calculate the emissions of the other criteria pollutants (CO, VOC, and PM) using South Coast AQMD-approved emission factors. In addition, the commenter has never challenged the South Coast AQMD significance thresholds which are stated as pounds per day mass emissions in any of the previous court cases.

Response 1-12

This comment asserts that the South Coast AQMD must prepare a revised analysis that “considers normal operations as the baseline for the impact analysis" and that the revised analysis must include sufficient information to support significance conclusions. The South Coast AQMD disagrees that the EIR must be revised. A revised analysis to establish the baseline is not necessary as the baseline used in the Draft EIR for the ULSD Project was established in accordance with CEQA Guidelines §15125 and the direction of the California Supreme Court in *CBE v. SCAQMD*. As stated in Response 1-7, the Court stated that: “We do not attempt here to answer any technical questions as to how existing refinery operations should be measured for baseline purposes in this case or how similar baseline conditions should be measured in future cases . . . Neither CEQA nor the CEQA Guidelines mandates a uniform, inflexible rule for determination of the existing conditions baseline. Rather, an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." For additional detailed information regarding establishing the baseline for the ULSD Project, refer to the 2014 Draft EIR pages 3-1 and 3-2 and to Response to Comments 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, 1-73.

Response 1-13

This comment summarizes a number of CEQA requirements including the following: an EIR provides information to provide public agencies (the correct citation is to government decision makers) and the public with information about the effect of a proposed project on the environment (CEQA Guidelines §15002) and to identify ways that environmental damage can be avoided or reduced (*Berkeley Keep Jets Over the Bay Comm. V. Board of Port Comm.*). The comment continues to summarize CEQA requirements stating that CEQA requires public agencies to avoid or reduce environmental damage when possible by requiring alternatives or mitigation measures (CEQA Guidelines §15002), etc. The comment then asserts that the 2014 Draft EIR fails to meet the above standards in several respects. The comment asserts that the Draft EIR fails to disclose all relevant information relevant to project emissions; this assertion is incorrect – refer to Responses 1-44, 1-62, 1-63, 1-69, 1-76, 1-78. The comment asserts that the Draft EIR fails to analyze maximum potential to emit; this assertion is incorrect – refer to Responses 1-46, 1-54, 1-59, 1-60, 1-67, 1-70, 1-77. The comment asserts that the Draft EIR fails to adequately analyze hydrogen production emissions; this assertion is incorrect – refer to Responses 1-44, 1-53, 1-54, 1-55, 1-56, 1-58, 1-59, and 1-61. The comment asserts that the Draft EIR fails to adequately analyze replacement heater emissions; this assertion is incorrect – refer to Responses 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70. The comment asserts that the Draft EIR fails to analyze emission impacts from increased steam demand; this assertion is incorrect – refer to Responses 1-3, 1-44, 1-78 and 1-80. Finally, the comment asserts that the Draft EIR fails to adequately analyze emissions from increased electricity demand; this assertion is incorrect – refer to Responses 1-44, 1-74, 1-75, 1-76, and 1-77. The comment then says that the 2014 Draft EIR fails to mitigate significant impacts. It should be noted that the 2014 Draft EIR concluded, based on substantial evidence, that air quality impacts from the ULSD Project would be less than significant. Therefore, mitigation measures are not required. However, to further support the conclusion that increased steam demand would not result in additional emissions, mitigation measure AQ-1 was imposed on the project. For information related to mitigation measure AQ-1, refer to Response 1-81.

Response 1-14

This comment contains general information on the required contents and purpose of an EIR including: an EIR protects the environment and informed self-government by including sufficient detail and reflecting the agency's good faith effort at full disclosure, etc. This comment does not specifically refer to the 2014 Draft EIR so no further response is necessary.

Response 1-15

This comment summarizes comments made in Attachment A of Comment Letter 1 that the 2014 Draft EIR estimates emissions from several project components (for example fugitive components, replacement heater in Unit 90, reactivation of storage tank 331, increased hydrogen production increased electricity demand, truck transport, and steam demand), but that the analysis focuses narrowly on Unit 90 and does not consider emission increases that occur at existing equipment required to support Unit 90. According to footnotes 41, 43, 44 and 45, these assertions are made in Attachment A on pages 1 and 5, which contain comments 1-38, 1-39, 1-46, 1-47, and 1-48. Therefore, please refer to Responses 1-38, 1-39, 1-46, 1-47, and 1-48.

Response 1-16

This comment asserts that the 2014 Draft EIR does not include information related to CO emissions. The footnote to this assertion refers to Attachment A of Comment Letter 1, page 14. The South Coast AQMD disagrees with this assertion. Comment 1-66 is the only comment on page 14 of Attachment A that addresses CO emissions. Therefore, refer to Response 1-66. For additional information on CO emissions from the ULSD Project, refer to Responses 1-62, 1-63, 1-67, and 1-68. The comment again asserts that the 2014 Draft EIR did not include emissions from several sources. This is incorrect. With respect to increased electricity generation, refer to Responses 1-74, 1-75, 1-76, and 1-77. With respect to increased demand for hydrogen, refer to Responses 1-53, 1-54, 1-55, 1-56, 1-58, 1-59, and 1-61. With respect to lead emitting equipment, refer to Response 1-44. With respect to increased steam production, refer to Responses 1-3, 1-78, 1-79,1-80, and 1-81. Therefore, the South Coast AQMD disagrees with the assertion that the 2014 Draft EIR is inadequate as an informational document as all of the emissions raised in the comments were analyzed and disclosed. Pursuant to CEQA Guidelines, the analysis evaluated reasonably foreseeable indirect physical changes to the environment (§15064(d)).

Response 1-17

The comment summarizes several basic CEQA principles illustrated by the holding in *County of Inyo v. Yorty* (1973) 32 Cal.App.3d 795 and CEQA Guidelines § 15126.2(a).

The comment presents a truncated and therefore misleading version of the holding in *San Joaquin Raptor Rescue Center v. County of Merced* (2007) 149 Cal.App. 4th 645. The court held that due to the wide swings in potential production, it was necessary in that case for the EIR to include "some analysis of the impacts that would result from peak levels of production." But this was not a blanket proclamation of a legal requirement. Rather, the court then proceeded to carefully consider each of the environmental topics at issue. It found that while some environmental topics required more analysis of peak impacts (e.g., groundwater and surface water), others warranted a different approach. For example, the court accepted use of average annual traffic in evaluating the impacts to the road's physical conditions over a 20 year period, while at the same time requiring the EIR to include added analysis of operations that more frequently approached the peak. Even then, the court was careful to state that it was "unnecessary to assume maximum production would occur every year." The court also rejected petitioners' challenge to the peak daily traffic analysis, in which the EIR took the trips generated on the maximum production day and assumed they would be spread evenly (i.e., averaged) over the course of the business day. Petitioners argued that this averaging might understate the impacts if more trucks were concentrated during the peak traffic hours. But the court concluded that "such minute detail was not required in the analysis in question." In sum, the court carefully considered each impact at issue and whether the use of average or peak production was appropriate in evaluating that impact.

In the case of air quality impacts from the ULSD Project, and the emission estimates criticized in many of the comments, the significance threshold is stated in pounds per day of emissions. The commenter has not challenged the significance threshold. The South Coast AQMD has historically applied this threshold by evaluating the increases in peak daily emissions, as determined by comparing the pre-project actual peak to the post project potential to emit (i.e., the maximum amount of emissions that the equipment is allowed under the permit). In this way the data evaluated in the EIR and the impacts conclusions match the units and time periods of the significance threshold.

Response 1-18

In this comment it is asserted that the 2014 Draft EIR failed to adequately analyze project emissions because it did not analyze the maximum potential to emit during the post-project period. Footnote 51 then refers to summary information on page 1-11 of the 2014 Draft EIR. The discussion on page 1-11 summarizes why a two-year duration, years 2006 to 2008, was chosen as the post-project period and nowhere on the page does it state that impacts were assessed by using average emissions rather than peak day emissions. Peak day emissions were used to establish the post-project period and a complete discussion can be found in the 2014 Draft EIR pages 3-1 and 3-2, as well as Responses to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76.

Once again the comment is made that no “rational” basis is made for selecting 2006 to 2008 as the post-project period other than matching the two-year baseline duration. The footnote to this assertion again references page 1-11 of the 2014 Draft EIR. As already noted, page 1-11 is part of the summary of the actions (ULSD Project) and its consequences as required by CEQA Guidelines §15123. Since it is a summary, it does not include all of the information used to establish the post-project period. A more robust discussion on establishing the post-project period can be found in the 2014 Draft EIR pages 3-1 and 3-2. See also Responses to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76.

Comment 1-18 makes the incorrect assertion that the post-project period corresponds to a severe recession so fuel demand and, thus, refinery emissions would have declined. Footnote 53 to this comment cites Attachment A of Comment Letter 1, pages 4 and 7. Page 4 does not include any assertion that a severe recession caused fuel demand and, thus, refinery emissions to decline. Comment 1-53 on page 7 does include such an assertion. Therefore, refer to Response 1-53. The comment also repeats an assertion made in comment 1-53 that refinery emissions in the year 2007 were among the lowest as shown in 2014 Draft EIR Table 3.1-3 (citation is footnote 54) because of the effects of the recession. This assertion is also refuted in Response 1-53 where it is stated that the 2007 data only includes six months of data (July through December 2007) as the SCAQMD changed from a fiscal reporting year (July through June) to a calendar reporting year (January through December) in this timeframe.

Comment 1-18 also asserts that daily hydrogen demand data should have been provided to support the decision to use 2006 to 2009 as the post-project period, so it is unclear if the post-project emissions represent peak day. Footnotes 55 and 56 to the comment refer to Attachment A to the Comment Letter 1, page 8. Page 8 includes all of comments 1-55, 1-56, 1-57, and part of comment 1-58. Therefore, refer to Responses 1-55, 1-56, 1-57, and 1-58, which address these assertions.

<u>Response 1-19</u>

This comment implies that the analysis in the 2014 Draft EIR used peak emissions to establish the pre-project baseline emissions and low average emissions to establish the post-project emissions. This comment provides no evidence for this assertion and is incorrect. For detailed information relative to establishing the baseline and baseline emissions, refer to the 2014 Draft EIR pages 3-1 and 3-2 and Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, and 1-73. For detailed information with regard to establishing the post-project period and emissions, refer to Responses 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76. Footnote 59 then references Attachment A, pages 2 and 3. Pages 2 and 3 include comments 1-39 through 1-43. Therefore, refer to Responses 1-39 through 1-43. Footnote 60 to the comment references Attachment A, pages 15 and 16. Pages 15 and 16 include comments 1-68 through 1-71. Therefore, refer to Responses 1-68 through 1-71.

The comment claims that "It is unclear why the District insists on using average emissions rather than the maximum potential to emit, as it has done in other cases." The comment then references Footnote 61 regarding comments that CURE made on the Ultramar Inc. Wilmington Refinery Cogen Project Negative Declaration. As discussed in the 2014 ULSD EIR, the baseline emissions were based on peak day emissions during the 2002-2003 baseline period. For detailed information relative to establishing the baseline and baseline emissions, refer to the 2014 Draft EIR pages 3-1 and 3-2 and Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, and 1-73. The baseline emissions used for the Ultramar Inc. Wilmington Refinery Cogeneration Project

Negative Declaration were also based on the maximum actual daily emissions during the baseline period (2011)[3]. Therefore, the 2014 ULSD EIR and the Ultramar Negative Declaration were based on the same approach. Although Footnote 61 states that the baseline for the Cogen Project was faulty, the Ultramar Negative Declaration was certified by the South Coast AQMD, the Notice of Determination was filed, and there was no legal challenge to the document.

There is no legal basis for the claim that "a baseline of average or minimum emissions pre-Project should be compared to the maximum potential to emit pollutants post-Project." The Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence: "We do not attempt here to answer any technical questions as to how existing refinery operations should be measured for baseline purposes in this case or how similar baseline conditions should be measured in future cases… Neither CEQA nor the CEQA Guidelines mandates a uniform, inflexible rule for determination of the existing conditions baseline. Rather, an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." 48 Cal. 4th at 327, 328. The Supreme Court also stated that, in preparing the EIR, the South Coast AQMD is not required to use the same measurement method as used in the Negative Declaration: "The District is not necessarily required to use the same measurement method in the EIR as in the Negative Declaration. Whatever method the District uses, however, the comparison must be between existing physical conditions without the [ULSD] Project and the conditions expected to be produced by the project." 48 Cal. 4th at 328. As stated on page 3-1 of the Draft EIR, the 2002-2003 time period is considered to be the pre-ULSD Project of baseline conditions for Refinery operations as this represents the real timeframe during the environmental analysis development for the ULSD Project and was prior to the actual construction and operation of the ULSD Project. Therefore, the baseline used in the EIR was the actual refinery emissions in the 2002-2003 timeframe. These facts constitute substantial evidence, as directed by the Supreme Court.

The South Coast AQMD has long-established thresholds of significance for criteria pollutants that are daily and hourly standards.[4] These are derived from state and federal ambient air quality standards that measure compliance on an hourly or daily basis, as well as major sources thresholds in the federal Clean Air Act.[5] The South Coast AQMD significance thresholds examine peak daily scenarios to determine worst-case emissions for a project as they represent the maximum potential emissions from the project. Further, the Supreme Court has specifically acknowledged that peak impacts may be an important metric in measuring refinery operations.[6]

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[3] 2014 Negative Declaration for the Ultramar Inc. Wilmington Refinery Cogeneration Project. Note that the maximum actual daily emissions were based on the 98th percentile of the actual emissions. Available at http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/ultramar_neg_dec.pdf?sfvrsn=2

[4] See, *Citizens for Responsible Equitable Environmental Development v. City of Chula Vista* (2011) 197 Cal. App. 4th 327, 344. The Court determined that where it can be found that a project did not exceed the South Coast Air Quality Management's established air quality significance thresholds, the City of Chula Vista properly concluded that the project would not cause a significant environmental effect, nor result in a cumulatively considerable increase in these pollutants.

[5] See, CEQA Air Quality Handbook, South Coast AQMD, May 1993, pages 6-1 through 6-2.

[6] 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.")

As noted in the Draft EIR (page 3-34), the post-project emissions from Heater B-401 (new heater) are based on the maximum potential to emit (peak) as estimated from the South Coast AQMD permit application. Detailed emission calculations are discussed in Responses 1-45 and 1-46 and provided in Appendix B of the Final EIR. The Final EIR has been revised to include the peak hydrogen use, as well as to the average hydrogen use. Thus, the emissions methodology that the South Coast AQMD chose to use in its emissions analysis does not underestimate the proposed project's impacts. The Draft EIR correctly used incremental changes associated with the proposed project and compared the post-project peak daily potential emissions (maximum potential to emit) to the actual 2002-2003 refinery emission with the net result compared to the South Coast AQMD's significance thresholds.

For more details on the methodologies to determine emissions from the replacement heater, refer to Responses to Comments 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70.

Footnote 62 to the comment simply references Attachment A, which include comments 1-38 through 1-82. Therefore, refer to Responses 1-38 through 1-82.

Response 1-20

This comment cites CEQA and the CEQA Guidelines. However, the quotation cited as CEQA Guidelines sections 15064(d)(2)-(3) in fact only quotes from section 15064(d)(2), not subparagraph (3).

Response 1-21

The comment notes that removing sulfur to produce ultra-low sulfur diesel requires increased amounts of hydrogen, which was analyzed in the 2014 Draft EIR. The comment then asserts that the 2014 Draft EIR underestimates emissions from increased demand for hydrogen. Footnotes 67 and 68 to the comment references Attachment A to Comment Letter 1, page 9 regarding emission factors used to analyze emissions from increased hydrogen demand. Page 9 includes comments 1-58 and 1-59. Therefore, refer to Responses 1-58 and 1-59.

Response 1-22

The comment repeats an assertion in Attachment A to Comment Letter 1 that, to calculate increased hydrogen production emissions, the 2014 Draft EIR uses emission factors from the Final EIR for the Air Products Hydrogen Facility and Specialty Gas Facility (SCH#97071078), June 1998 (1998 Final EIR), but that the 1998 Final EIR does not show the emission factors used to analyze increased hydrogen production emissions. Footnotes 70 and 71 to this comment cite Attachment A, pages 8 and 9. Pages 8 and 9 contain comments 1-55 through 1-59. Therefore, refer to Responses 1-55 through 1-59. The comment also notes that Attachment A to Comment Letter 1 includes an alternative calculation of emissions from increased demand for hydrogen. Footnotes 72, 73, and 74 to this comment cite Attachment A to Comment Letter 1, page 10. Page 10 contains comment 1-59. Therefore, refer to Response 1-59.

Response 1-23

This comment asserts that the 1998 Final EIR is outdated because it used a flare emission factor that was subsequently replaced by U.S. EPA with a higher emission factor. Footnotes 75 and 76 to this comment cites Attachment A, page 10. Page 10 contains comment 1-59. Therefore, refer to Response 1-59. The comment then asserts that using the updated factor would result in significant NOx emissions. Footnote 77 to this comment cites Attachment A to Comment Letter 1, page 11. Page 11 contains comments 1-59 through 1-61. Therefore, refer to Responses 1-59 through 1-61.

As further explained in Response 1-59, using actual data reported by the Air Products Hydrogen Plant to the South Coast AQMD as part of their annual emissions, the total NOx emissions from the operation of the entire hydrogen plant are well below the ULSD NOx emissions estimated by Phyllis Fox in Attachment A of this comment letter (see Response 1-59 for further details). Also, as further explained in Response 1-60, the U.S. EPA NOx emission factor for flaring referenced in Comment 1-23 was not included in the U.S. EPA's Emissions Estimation Protocol for Petroleum Refineries when it was finalized in April 2015. The NOx emission factor for flares is found in Table 6-2 of the U.S. EPA document and is 0.068 lb NOx/10^6 mmBtu and not 2.9 lb/mmBtu as referenced in this comment. See Responses 1-59 through 1-61 for complete details.

Response 1-24

This comment generally repeats the assertion in comment 1-23 that using the U.S. EPA's flare emissions factors to assess flare emissions at the Air Products Hydrogen Plant would result in NOx emissions that would exceed the South Coast AQMD's operational NOx significance threshold and, thus, would require mitigation. With regard to the assertion regarding NOx emissions from the flare at the Air Products Hydrogen Plant refer to Responses 1-59 and 1-60. With regard to mitigation measures, refer to Response 1-81. Consequently, the South Coast AQMD disagrees with the assertion that the 2014 Draft EIR fails to comply with the requirements of CEQA.

Response 1-25

This comment asserts that the analysis used a flawed baseline to determine pre-project emissions for Heater B-201. The South Coast AQMD disagrees with this assertion, which is addressed in detail in Response 1-62. This comment also asserts that an appropriate emissions analysis was not conducted for replacement Heater B-401. With regard to the replacement Heater B-401, refer to Responses 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70. In addition, footnote 83 to this comment cites Attachment A to Comment Letter 1, page 11. Page 11 contains comments 1-59 through 1-61. Therefore, refer to Responses 1-59 through 1-61.

Footnote 79 to the comment references Pub. Res. Code § 21081.6(b) and Guidelines § 15126.4(a)(2). These provisions address mitigation measures and conditions of approval; they do not concern the topic of the comment. Nonetheless, the South Coast AQMD has considered these and all relevant provisions of CEQA in preparing the EIR.

Response 1-26

This comment repeats assertions made in Attachment A to Comment Letter 1 that post-project emissions in the 2014 Draft EIR are not supported by evidence and the emissions from Heater B-401 were underestimated. Footnote 84 to this comment cites Attachment A to Comment Letter 1, pages 12 and 13, yet pages 12 and 13 contain comments 1-61 through 1-66. Therefore, refer to Responses 1-61 through 1-66, if referring to those comments. This comment repeats assertions made in Attachment A that permit emission limits cannot be verified because the Wilmington Refinery's Title V permit has not be updated. Heater B-401 and associated conditions and emissions limits have been included in Section H (Permit to Construct) of the Title V permit since 2005. Once the construction and source testing was completed for the equipment, the permit was converted from a Permit to Construct to a Permit to Operate. Please note that Section D (Permit to Operate) of the August 31, 2017 Title V permit includes Heater B-401. The applicable portions of the 2017 Title V permit are provided in Attachment 3. Footnote 86 to this comment cites Attachment A to Comment Letter 1, page 12. Page 12 contains comments 1-61 and 1-62. Therefore, refer to Responses 1-61 and 1-62.

In general, Responses 1-62 through 1-66 provide detailed information and calculations to show that the emissions from Heater B-401 were not underestimated, the emissions are enforced as part of the South Coast AQMD permit to operate (Title V permit), and that source testing for Heater B-401 is required to show compliance with the South Coast AQMD permit to operate. In fact, initial source testing was performed as required under the permit to construct, on February 6, 2007. The initial test included emissions of ROG, CO, PM10, PM2.5, NH_3, SO_x and NO_x. The permit to operate for the heater also requires tests of PM10 emissions every three years and of CO emissions every five years. In lieu of source tests of CO, the permit allows as an alternative annual verifications via portable analyzer.

Response 1-27

This comment repeats assertions made in Attachment A to Comment Letter 1 that review of the permits for the ULSD Project is essential because they may contain emission limit exceptions. Footnotes 88 through 91 to this comment cites Attachment A to Comment Letter 1, page 13. Page 13 contains comments 1-63 through 1-66. Therefore, refer to Responses 1-63 through 1-66. As stated in those responses, the emissions from Heater B-401 are limited through South Coast AQMD permit conditions and applicable portions of the South Coast AQMD operating permit for Heaters B-201 and B-401 are included in Attachments 2 and 3, respectively, to these responses to comments. Specifically, Table 15 (see Response 1-65) provides information on the emissions permit limits, averaging periods, and South Coast AQMD permit conditions for Heater B-401.

Response 1-28

This comment repeats assertions made in Attachment A to Comment Letter 1 that the permit limits underestimate post-project NOx emissions. Footnote 92 to this comment cites Attachment A to Comment Letter 1, pages 13 and 14. Pages 13 and 14 contain comments 1-63 through 1-67. Therefore, refer to Responses 1-63 through 1-67. This comment further asserts that the analysis of NOx emissions from replacement Heater B-401 does not account for uncontrolled emissions when the SCR unit is offline, which would result in NOx emissions that exceed the applicable operational significance threshold for NOx. Footnote 94 to this comment cites Attachment A to Comment Letter 1, page 13. Page 13 contains comments 1-63 through 1-66. Therefore, refer to Responses 1-63 through 1-66. Footnotes 95 and 96 to this comment cites Attachment A to Comment Letter 1, page 14. Page 14 contains comments 1-66 and 1-67. Therefore, refer to Responses 1-66 and 1-67.

Response 1-66 provides detailed information regarding the enforcement of emissions as part of the South Coast AQMD permit to operate (Title V permit), and that source testing for Heater B-401 is required to show compliance with the South Coast AQMD permit, as required by the RECLAIM program and regulations. As further shown in Response 1-67 the revisions to the NOx emission calculations for the ULSD Project, NOx emissions resulting from the total project were estimated to range from 6.8 to 12.9 pounds per day, which is well below the NOx significance threshold of 55 pounds per day (see Response 1-67, Table 16). As further discussed in Response 1-67, the NOx emissions from Heater B-401 during startup and shutdown were less than 5 pounds per day. See Response 1-67 for more details emission estimates.

Response 1-29

This comment repeats assertions made in Attachment A to Comment Letter 1 that the 2014 Draft EIR underestimates CO emissions. Footnotes 97, 100, 101, and 102 to this comment cite Attachment A to Comment Letter 1, page 14. Page 14 contains comments 1-66 and 1-67. Therefore, refer to Responses 1-66 and 1-67.

Response 1-30

This comment repeats assertions made in Attachment A to Comment Letter 1 that the 2014 Draft EIR underestimates PM10 and PM2.5 emissions. Footnotes 103 and 104 to this comment cite Attachment A to Comment Letter 1, page 14. Page 14 contains comments 1-66 and 1-67. Therefore, refer to Responses 1-66 and 1-67. Additional information regarding the calculation of PM10 and PM2.5 emissions can also be found in Response to Comments 1-62, 1-63, and 1-64. Comment 1-30 also repeats assertions made in Attachment A to Comment Letter 1 that the 2014 Draft EIR should have provided stack tests to confirm the emission factors used. Footnote 105 to this comment cites Attachment A to Comment Letter 1, page 15. Page 15 contains comments 1-68 and 1-69. Therefore, refer to Responses 1-68 and 1-69. This comment repeats assertions made in Attachment A that PM10 and PM2.5 emissions are underestimated because the analysis did not account for secondary particulate formation from ammonia used by the SCR. Footnote 106 to this comment cites Attachment A to Comment Letter 1, page 15. Page 15 contains comments 1-68 and 1-69. Therefore, refer to Responses 1-68 and 1-69. Footnote 107 also to this comment cites Attachment A to Comment Letter 1, page 16. Page 16 contains comments 1-70 and 1-71. Therefore, refer to Responses 1-70 and 1-71. Finally, the South Coast AQMD disagrees with the assertion that the 2014 Draft EIR is deficient with regard to NOx emission estimates. The Draft EIR complies with all relevant CEQA requirements and includes a robust and accurate analysis of NOx emissions.

Response 1-31

This comment repeats assertions made in Attachment A to Comment Letter 1 that emissions from increased electricity demand were based only on horsepower ratings of select new equipment. Further, the comment asserts, the analysis of increased emissions from the increased demand for electricity should include a list of each piece of equipment with vendor specifications and identify whether the analysis of electricity demand only includes new equipment. Footnotes 109 and 110 to this comment cite Attachment A, page 17. Page 17 contains comments 1-71 through 1-74. Therefore, refer to Responses 1-71 through 1-74. Based on the information in the 2014 Draft EIR and the responses to all comments submitted on that document, the EIR for the ULSD Project complies with all applicable CEQA requirements, including a good faith effort at full disclosure and serving as an informational document.

Response 1-32

This comment repeats assertions made in Attachment A to Comment Letter 1 that questions whether the ULSD analysis for the recycle gas compressor is based on a horsepower rating of 400 hp or 200 hp. This comment also repeats assertions made in Attachment A to Comment Letter 1 that questions whether the analysis of emissions from increased electricity demand includes the pumps. Footnotes 113 and 114 to this comment cite Attachment A, page 17. Page 17 contains comments 1-71 through 1-74. Therefore, refer to Responses 1-71 through 1-74. As discussed in Response 1-74 the reactivated compressor was doubled in size from 100 hp to 200 hp (and not from 200 hp to 400 hp as suggested in Comment 1-32). For clarity, the Final EIR has been modified to identify the horsepower rating of the recycle gas compressor.

Response 1-33

This comment repeats assertions made in Attachment A that the increased electricity demand calculated for the ULSD Project is presented inconsistently between the text of the 2014 Draft EIR and Appendix B. Footnote 116 to this comment cites Attachment A to Comment Letter 1, page 17 and footnote 117 to this comment cites Attachment A to Comment Letter 1, pages 17 and 18. Pages 17 and 18 contain comments 1-71 through 1-76. Therefore, refer to Responses 1-71 and 1-76.

Response 1-34

This comment repeats assertions made in Attachment A to Comment Letter 1 that the 2014 Draft EIR did not explain how the pre-project electricity demand baseline was selected. Similarly, this comment repeats assertions made in Attachment A that the 2014 Draft EIR's post-project estimate of increased electricity demand is unsupported. Footnotes 118 and 119 to this comment cite Attachment A to Comment Letter 1, page 18. Page 18 contains comments 1-74 through 1-76. Therefore, refer to Responses 1-74 through 1-76. Based on the information provided in the 2014 Draft EIR and the referenced responses, the South Coast AQMD disagrees that the analysis fails to provide pertinent information to allow public review of the calculations.

Response 1-35

This comment repeats assertions made in Attachment A to Comment Letter 1 that the analysis underestimates increased electricity demand because it only included electricity demand from new equipment, not existing equipment. This comment also repeats assertions made in Attachment A to Comment Letter 1 that the analysis did not include emission increases from indirect sources such as heaters, boilers, turbines, or cooling water. Footnotes 120 through 122 to this comment cite Attachment A to Comment Letter 1, page 18. Page 18 contains comments 1-74 through 1-76. Therefore, refer to Responses 1-74 through 1-76. Also, see Response 1-77 regarding increased electricity use associated with the ULSD Project and more specifically in Response 1-46 regarding electricity from the Sulfur Recovery Plant. Based on the information provided in the 2014 Draft EIR and the referenced responses, the EIR for the ULSD Project complies with all relevant CEQA requirements, therefore, the South Coast AQMD disagrees that the analysis fails as an informational document.

Comment 1-35 indicates that in Attachment A, Dr. Fox found that "the Project would increase electricity demand from existing equipment as well, plus any supporting equipment such as sulfur removal and cooling water." Please note that on pages 18 and 19 of Attachment A, Dr. Fox provides comments on the increase in electricity but does not provide any evidence of an increase in electricity demand associated with cooling water. Therefore, no evidence has been provided that there is any increase in electricity from "cooling water" associated with the Project. The ULSD project did not result in an increase in cooling water and no additional electricity was required for cooling water purposes.

Response 1-36

This comment repeats assertions made in Attachment A to Comment Letter 1 that the 2014 Draft EIR fails to mitigate significant NOx air quality impacts and the one mitigation measure identified is "inadequate" to mitigate NOx emissions. This assertion is made in comment 1-81. Therefore, refer to Response 1-81. As discussed in Response 1-81, the Draft EIR demonstrated that ULSD emissions would not be significant and that additional steam demand for the ULSD had no effect on steam production in the Refinery and, thus, caused no ULSD Project emission increases associated with steam production. Therefore, no mitigation is required under CEQA.

This comment also asserts that, even though NOx emissions from replacement Heater B-401 are controlled using low NOx burners and SCR, these controls fail to reduce NOx emissions to less than significant. It is assumed that this comment is a reference to Attachment A to Comment Letter 1, comments 1-64 and 1-67 (alleging the permits contain exceptions to emissions limits, such as during startups and shutdowns); 1-65 (alleging the permits contain averaging times longer than one day while impacts are based on daily emissions); and 1-66 (alleging the permit does not require adequate testing and monitoring to ensure emission limits are not exceeded). Therefore, refer to Responses 1-64 through 1-67.

Response 1-37

The comment letter concludes by asserting that the 2014 Draft EIR for the ULSD Project: does not meet the requirements of CEQA; must be revised to include an "adequate" description of the pre-project baseline; must provide an analysis of, and mitigation for significant NOx emissions, and must be recirculated for public review. The South Coast AQMD disagrees with these assertions. The 2014 Draft EIR complies not only with all relevant CEQA requirements, but fully addresses the holdings in *CBE v. SCAQMD*. The analysis of impacts from the ULSD Project is a robust and detailed analysis that fully discloses potential impacts from the project and is based on actual operation of the project. Minor non-substantive modifications have been made to the Final EIR to improve clarity and provide additional information in Response to Comments submitted on the 2014 Draft EIR. Such modifications do not rise to level of requiring recirculation of the Draft EIR. Finally, it is up to the South Coast AQMD's decision makers whether or not to certify the Final EIR.

Attachment A – Comments on Draft Environmental Impact Report for the Phillips 66 Ultra Low Sulfur Diesel Project

Response 1-38

These introductory comments provide summaries of more detailed comments made later in this attachment. Individual summary comments are identified here and references are made to the South Coast AQMD's responses to the more detailed comments made later in this attachment.

This introductory comment asserts that the Draft EIR for the proposed project does not "cure the deficiencies found by the California Supreme Court." For detailed responses to this assertion see Responses 1-3, 1-5, 1-7, and 1-9. Further, the comment asserts that the Draft EIR does not support its key calculations because it excludes key data assumptions, and calculations used to estimate project emissions. The South Coast AQMD generally disagrees with this assertion and provides detailed responses to each issue identified here in Responses to comments 1-40 through 1-80. As discussed in Response 1-46, the Draft EIR did not estimate emissions associated with an increase in sulfur handled at the refinery as a result of the ULSD Project. These emissions estimates are provided in Response 1-46 and included in the Final EIR.

This summary comment asserts that the Draft EIR improperly calculates pre-project (baseline) emissions by using the maximum daily emissions in the years 2002-2003 rather than average daily emissions. The South Coast AQMD disagrees with this assertion. For detailed information regarding establishing the baseline for the ULSD Project, refer to Response to Comments 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, 1-73.

This summary comment also asserts that the Draft EIR improperly calculates post-project (operational) emissions using annual average emissions rather than highest daily emissions based on permit limits or physical constraints of the subject equipment. This assertion is incorrect and the South Coast AQMD did not use average annual emissions for post-project emissions but instead used the maximum potential to emit for the equipment. The exception to this was associated with hydrogen production and the Final EIR has been revised to include peak hydrogen production. For detailed information regarding establishing the post-project period for the ULSD Project, refer to Response to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76.

This summary comment asserts that NOx (and other criteria pollutants) emissions from the proposed project identified in the Draft EIR were underestimated as indicated by other more detailed comments made in this attachment that purport to show flaws in the analysis. As discussed in Response 1-46, the Draft EIR did not estimate emissions associated with an increase in sulfur handled at the refinery as a result of the ULSD Project. These emissions estimates are provided in Response 1-46 and included in the Final EIR but do not change the conclusions in the Draft EIR. Additional information on NOx emissions from the proposed project is explained in further detail in Responses 1-46, 1-54, 1-59, 1-60, 1-67, 1-70, and 1-77.

Response 1-39

This comment describes the commenter's qualifications and background. Because it is not specifically a comment on the project or the analysis in the Draft EIR, no response is required. In addition, the commenter references Exhibits 2 and 3, which were comments on the 2004 and 2005 CEQA documents, respectively, for the ULSD Project. Comments in these exhibits are generally not relevant to the 2014 Draft EIR for the ULSD Project, as responses to those comments have previously been prepared, so no further response is necessary here. In addition, most of the topics mentioned in the comments in Exhibits 2 and 3 that were raised in timely petitions for writ of mandate filed in 2004 and 2005 were rejected by the Superior Court or the Court of Appeal. Another focus of the comments in Exhibits 2 and 3 was the issue of baseline. The 2014 Draft EIR fully addresses the holdings in *CBE v. SCAQMD*. The California Supreme Court held that the Negative Declaration improperly used the maximum *permitted* activity as the baseline. The Supreme Court also found that there was a fair argument that the ULSD Project may result in significant impacts related to air emissions during operations, and so remanded for preparation of an EIR.

The comment states that a prior owner of the refinery retained Phyllis Fox as a consultant on undisclosed matters. The comment does not state that Phyllis Fox advised the prior refinery owner with respect to the equipment or even the refinery that is the subject of this EIR, nor does it identify the time period during which she was retained by the prior owner. Inquiries with prior owners reveal that Dr. Fox may have been retained in some capacity by Union Oil Company (Unocal), who sold the refinery to Tosco in 1997, and that Dr. Fox was not a consultant to Tosco. Neither Phillips Petroleum, ConocoPhillips or Phillips 66 has retained Phyllis Fox since Phillips Petroleum acquired Tosco and the refinery in 2001. Thus, it has been at least 20 years since Phyllis Fox visited the refinery, if ever. The refinery has undergone major changes in the years subsequent to Unocal's ownership, and it is unclear whether Phyllis Fox's prior exposure to this refinery, if any, would remain relevant to the ULSD Project. Table 2 provides a list of refinery projects that have been the subject of CEQA documents since the Refinery was sold by Unocal.

TABLE 2

Phillips 66 Refinery Projects Subject to CEQA

SCH#	Lead Agency	Project Title	Project Description	Type of CEQA Document	SCH Date
2013091029	South Coast AQMD	Phillips 66 Los Angeles Refinery Carson Plant - Crude Oil Storage	Waterbourne Crude Tank	Neg. Dec.	December 2014
2008051097	South Coast AQMD	ConocoPhillips Los Angeles Refinery Tank Replacement Project	LARC Tanks 2625, 2, 21, & 280; LARW Tanks 68 & 78	Neg. Dec.	5/22/2008
2006111138	South Coast AQMD	ConocoPhillips Los Angeles Refinery - PM10 and NOx Reduction Project	FCCU Wet Gas Scrubber and LARW Boiler 7 & LARC Boiler 11 SCR's	EIR	4/4/2007
2004011095	South Coast AQMD	ConocoPhillips Los Angeles Refinery - Ultra Low Sulfur Diesel Project	ULSD Modifications	Subsequent Neg. Dec.	Oct-05
2004011095	South Coast AQMD	ConocoPhillips Los Angeles Refinery - Ultra Low Sulfur Diesel Project	ULSD Modifications	Neg. Dec.	6/21/2005
2004011066	South Coast AQMD	ConocoPhillips Los Angeles Refinery Carson Plant SCR Project	Boiler 10 SCR	Neg. Dec.	1/15/2004
2000091056	South Coast AQMD	Tosco Los Angeles Refinery Phase 3 Reformulated Fuels Project	CARB Phase 3 Gasoline	EIR	1/12/2001
2000051144	South Coast AQMD	Tosco Los Angeles Refinery Ethanol Import and Distribution Project	MTBE Phase Out	Neg. Dec.	5/26/2000

Response 1-40

Comment 1-40 repeats the summary of comments already made in Comment 1-38 and that are made in more detailed comments later in the Attachment A. The South Coast AQMD again disagrees with these repeated assertions as explained as follows. This comment again summarizes the assertion that the Draft EIR does not "cure the deficiencies, that is, the baseline issue, found by the California Supreme Court." For detailed responses to this assertion see Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, and 1-73. This comment also repeats the assertion made in Comment 1-38 that the Draft EIR does not support its key calculations because it excludes key data assumptions, and calculations used to estimate project emissions. Refer to Responses 1-44, 1-62, 1-63, 1-69, 1-76, and 1-78. Finally, this comment repeats the assertion that NOx (and other criteria pollutants) emissions from the proposed project identified in the Draft EIR were underestimated as indicated by other comments made in this attachment that purport to show flaws in the analysis. Refer to Responses 1-46, 1-54, 1-59, 1-60, 1-67, 1-70, and 1-77.

Response 1-41

Comment 1-41 primarily reiterates how the Draft EIR determined the emissions impact from the project. Then the commenter highlights each potential impact area as a result of the project.

In Comment 1-41 it is again asserted that fugitive emissions from the proposed project were underestimated. This assertion is made in more detail in comment 1-45. The South Coast AQMD disagrees with this assertion. Refer to Response 1-45 for a detailed response to this assertion.

This comment again summarizes an assertion made in more detail later in this attachment that emissions from a replacement heater were underestimated. The South Coast AQMD disagrees with this assertion. For detailed responses to this assertion refer to Responses to Comments 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70.

In Comment 1-41 it is asserted that emissions from storage tank 331 were underestimated. This assertion is again made in comment 1-47. The South Coast AQMD disagrees with this assertion. Refer to Response 1-47 for a detailed response to this assertion.

Comment 1-41 again summarizes an assertion made in more detail later in this attachment that emissions from hydrogen production were underestimated. The Draft EIR included average actual daily emissions for hydrogen production associated with the ULSD Project. The Final EIR has been revised to include average actual emissions (CO 2.28 lbs/day, VOC 2.28 lbs/day, NOx 3.50 lbs/day, SOx 0.1 lbs/day, PM10 2.73 lbs/day, PM2.5 2.73 lbs/day), as well as peak actual daily emissions in order to provide a worst-case estimate of project-related emission increases (CO 6.26 lbs/day, VOC 6.26 lbs/day, NOx 9.60 lbs/day, SOx 0.27 lbs/day, PM10 7.49 lbs/day, PM2.5 7.49 lbs/day). These updated emissions do not change the conclusions in the EIR or cause the project to exceed the significance thresholds. See Response 1-54 for detailed hydrogen production emission calculations. For additional detailed responses to hydrogen production emissions refer to Responses to Comments 1-53, 1-55, 1-56, 1-58, 1-59, and 1-61.

Comment 1-41 again summarizes an assertion made in more detail later in Attachment A that emissions from electricity demand were underestimated. The Final EIR has been revised to include additional emissions associated with electricity demand at the Sulfur Recovery Plant (CO 0.3 lbs/day, VOC 0.0 lbs/day, NOx 1.7 lbs/day, SOx 0.2 lbs/day, PM10 0.1 lbs/day, PM2.5 0.1 lbs/day) (see Response 1-46). These updated emissions do not change the conclusions in the EIR or cause the project to exceed the significance thresholds. For detailed responses to other portions of this assertion refer to Responses to comments 1-74, 1-75, 1-76, and 1-77.

This comment summarizes an assertion made later in Attachment A that emissions from truck trips were underestimated. The Final EIR has been revised to include one additional truck trip per day for the transport of sulfur from the Refinery associated with the USLD Project. The emission increases associated with one additional truck trip were: CO 0.07 lbs/day, VOC 0.01 lbs/day, NOx 0.09 lbs/day, SOx 0.0 lbs/day, PM10 0.0 lbs/day, PM2.5 0.0 lbs/day. These updated emissions do not change the conclusions in the EIR or cause the project to exceed the significance thresholds. This comment is again made in comment 1-46. For a detailed response to this assertion refer to Response 1-46.

This comment again summarizes an assertion made in more detail later in this attachment that emissions from steam demand were underestimated. The Final EIR has been revised to include an increase in steam use at the Sulfur Recovery Plant, as discussed in Response 1-46 with an estimated emissions increase of: CO 5.04 lbs/day, VOC 0.7 lbs/day, NOx 1.33 lbs/day, SOx 0.36 lbs/day, PM10 0.45 lbs/day, PM2.5 0.45 lbs/day. For detailed responses to this assertion for Unit 90 steam demand, refer to Responses to comments 1-3, 1-78, 1-79, and 1-80.

This comment also provides a simplistic description of the way impacts should be calculated, that is, post-project emissions – pre-project emissions = increase in emissions. The comment then states, "The post-project emissions are the maximum emissions that can be released as a result of a project." This simplistic view of how to estimate impacts is sometimes useful, but it is by no means the only approach, and it is not always the best approach. At times, it can even be a little misleading, as the project may result in emission reductions (not only emission increases) and it may miss some of the nuances of estimating direct and indirect impacts from a project, as described in more detail in Response 1-45. As a side note, the equation as stated in Comment 1-41 assumes that impacts from a project are always greater than baseline conditions i.e., results in an increase in emissions. That is not always true.

For detailed information regarding establishing the post-project period, including identifying direct and indirect impacts, for the ULSD Project, refer to Response to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76. Comment 1-41 also makes assertions about what constitutes establishing a proper baseline for a project. As indicated in the following Responses to Comments the commenter's assertions regarding how to establish a baseline are largely inaccurate and in some cases unsupported by any evidence, CEQA, or CEQA case law. For more detailed responses regarding establishing the baseline for the proposed project, see Responses to Comments 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, and 1-73. For detailed information regarding establishing the post-project period, including identifying direct and indirect impacts, for the ULSD Project, refer to Response to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76.

Response 1-42

This comment again contains summaries of comments already made earlier and that are made in more detail in later comments. The South Coast AQMD again disagrees with these repeated assertions as explained as follows. Relative to establishing the baseline (pre-project emissions), refer to Responses to Comments 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, and 1-73. Relative to using the years 2006 through 2008 as the post-project period, refer to Responses 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76. Relative to methodologies to determine emission from the replacement heater, refer to Responses to Comments 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70. Relative to methodologies to determine emissions from hydrogen production, refer to Responses to Comments 1-53, 1-54, 1-55, 1-56, 1-58, 1-59, and 1-61. Relative to methodologies to determine electrical demand, refer to Responses to Comments 1-74, 1-75, 1-76, and 1-77.

Relative to methodologies to determine steam production, refer to Responses to Comments 1-3, 1-7, 1-78, 1-79, and 1-80. Comment 1-42 also references fugitive components (see Response to Comment 1-46), truck transport (see Response to Comment 1-46), and tank 331 (see Response to Comment 1-47).

Response 1-43

In this comment it is asserted that the reference cited for Table 3.3-6 in the 2014 Draft EIR, 1993 South Coast AQMD CEQA Air Quality Handbook (1993 Handbook) has, subsequent to 1993, been updated, and, therefore, is a significant omission because the updated significance thresholds for PM2.5 are lower than the 55 pounds per day threshold used in the 2014 Draft EIR. This assertion that the PM2.5 significance threshold has been updated is incorrect and shows a misunderstanding regarding how to apply the localized significance thresholds adopted by the South Coast AQMD, as explained in the following paragraphs.

First, the reference in Table 3.3-6, note (a), has been revised in the Final EIR to the latest version of the South Coast AQMD, Air Quality Significance Thresholds which is March 2015, available at: http://www.aqmd.gov/docs/default-source/ceqa/handbook/scaqmd-air-quality-significance-thresholds.pdf?sfvrsn=2. The only change to the threshold table between the Final EIR and the Draft EIR was the removal of the quarterly average federal lead standard because it was changed from 1.5 ug/m^3 per quarter to 0.15 ug/m^3 as a 3-month average. The PM2.5 thresholds remain unchanged.

Table 3.3-6 in the 2014 Draft EIR contains the most current air quality significance thresholds adopted by the South Coast AQMD Governing Board. Mass daily significance thresholds for criteria pollutants provided in the 1993 Handbook were adopted by the South Coast AQMD Governing Board in 1993. Several air quality significance thresholds identified in the 1993 Handbook have been revised by the South Coast AQMD Governing Board over the years, or additional thresholds adopted, to reflect the latest pollutant standards or attainment status of the region. For example, changes to the significance thresholds in the 1993 Handbook include developing and adopting a mass daily significance threshold for PM2.5, which was approved by the South Coast AQMD Governing Board in October 2006 (http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/pm-2-5-significance-thresholds-and-calculation-methodology). This PM2.5 significance threshold has been used by South Coast AQMD and has been recommended for use by other public agencies evaluating air quality impacts since that time. Other significance thresholds adopted by the South Coast AQMD and included in Table 3.3-6 of the 2014 Draft EIR include localized significance thresholds for NO_2, PM10, PM2.5, and CO, adopted by the South Coast AQMD Governing Board in July 2003 (http://www.aqmd.gov/home/governing-board/agendas-minutes). As a result, regardless of the reference for Table 3.3-6 in the 2014 Draft EIR, the significance thresholds identified in the table are accurate and reflect the most current air quality significance thresholds used by the South Coast AQMD and recommended for use by other public agencies, with the exception that the quarterly lead significance threshold has been eliminated. As a result, staff disagrees with the commenter that the citation for the PM2.5 significance threshold is a "*significant*" omission. Further, air quality impacts identified in the Draft EIR, including PM2.5 emissions, were calculated (see 2014 Draft EIR, Table 3.3-7) and compared to the applicable and correct significance thresholds. It was demonstrated in the Draft EIR that PM2.5 emissions would not exceed the applicable significance thresholds and, therefore, were concluded to be less than significant.

With regard to footnote 4 relative to localized significance thresholds for PM2.5, the commenter asserts that the analysis of localized PM2.5 emission impacts in the Draft EIR ignores the localized significance thresholds in Table B-2 of the 2006 *Final – Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds* (note: the comment mistakenly calls this the 2006 South Coast AQMD Handbook Update). The screening tables provided by the South Coast AQMD in the 2006 Final Methodology document used to determine significant localized impacts are only applicable to projects five acres or less in area. Projects greater than five acres are defined as larger projects. As stated in the South Coast AQMD's *Final Localized Significance Threshold Methodology* document (June 2003), "SCAQMD recommends that lead agencies perform project-specific modeling for larger projects in determining localized air quality impacts." The ULSD Project takes place throughout the refinery, which covers approximately 400 acres, thus, would be considered a larger project and the localized significance threshold screening tables in Table B-2 would not be applicable.

The South Coast AQMD provides guidance for larger projects to determine localized impacts either through dispersion modeling of onsite emissions sources or other appropriate South Coast AQMD-approved methodologies. Project-specific dispersion modeling results determine whether or not a larger project generates pollution concentrations that cause or contribute to an exceedance of the applicable ambient air quality standards or the localized significance thresholds for PM10 and PM2.5 at the sensitive receptor. The Draft EIR includes another approach for analyzing localized air quality impacts, stating "SCAQMD Rule 1303 provides a screening analysis to determine the potential for ambient air quality impacts in lieu of formal modeling." Table 3.3-9 of the 2014 Draft EIR lists the project emissions and compares them to the screening tables in Rule 1303 to determine whether or not the localized air quality impacts would cause or contribute to an exceedance of applicable ambient air quality standards or the localized significance thresholds for PM10 and PM2.5 at the sensitive receptor. If the ambient air quality standards are not exceeded, which was the case with the ULSD Project, then the localized impacts are determined to be less than significant. Thus, the 2014 Draft EIR's analysis did include an evaluation of localized PM2.5 air quality impacts and compared the results to an applicable screening threshold. See Draft EIR Section 3.3.2.3, which includes the PM2.5 analysis and the conclusion that localized impacts are less than significant.

In addition to the screening analysis that was completed in the Draft EIR, air quality modeling for Heater B-401 has been included in the Final EIR (see Appendix D). The peak day emission estimates for Heater B-401 were modeled to determine the potential ground level or localized air quality impacts. The peak day emissions, based on the emission calculations in Appendix B of the Draft and Final EIR, include: 6.04 lbs/day of CO; 5.4 lbs/day of VOC; 4.96 lbs/day of NOx; 4.19 lbs/day of SOx; 5.83 lbs/day of PM10; and 5.83 lbs/day of PM2.5. Note that the peak day emissions associated with Heater B-401 were modeled. The air quality modeling was worst-case since it did not account for the emission decreases associated with the removal of Heater B-201, which resulted in a decrease of 16.6 lbs/day of CO and 25.52 lbs/day of NOx emissions.

In order to determine the ground level concentrations, the U.S. EPA AERMOD (version 16216r) air dispersion model was used to calculate the annual average and maximum 1-hour, 3-hour, 8-hour, and 24-hour concentrations. Per South Coast AQMD guidelines, AERMOD model was run using the most recent meteorological data (2006-2011). The meteorological data are from the Long Beach meteorological station and are representative of the meteorological conditions at the Phillips 66 Refinery because it is the closest station to the project site. The AERMOD model used all regulatory default settings.

For most combustion sources, only a fraction of the NOx emissions coming from the stack is actually NO_2. NO_2 forms as nitrogen oxide (NO) interacts with the ozone in the atmosphere. The longer NO is exposed to ozone, the higher the conversion rate to NO_2. As such, NOx to NO_2 conversion becomes a function of distance from the stack and ambient ozone concentration. The model used the Ambient Ratio Method (EPA Tier 2 analysis) outlined in the *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W).

The maximum impact location for a receptor is determined from the applicable averaging periods from the AERMOD model output. The maximum ground level concentration and the Universal Tranverse Mercator (NAD 84) coordinates for each maximum impacted receptor were used. The detailed ambient air quality analysis is found in the Final EIR, Appendix D.

The unit maximum ground level concentrations are compared to the significance thresholds established in Rules 1303 and 2005 to demonstrate that the project will not cause a violation of any state or federal ambient air quality standard. The ambient air quality data for South Coastal Los Angeles County (Station No. 072 and 033), the closest ambient air quality monitoring station to the Phillips 66 Los Angeles Refinery, is used to establish background levels of CO, NO_2, PM10, and PM2.5. Federal NOx and SOx ambient background concentrations are based on the 98^{th} and 99^{th} percentile of the last 3 years of data, respectively.

The CO 1-hour, CO 8-hour, NO_2 1-hour, NO_2 annual average, SOx 1-hour, SOx 3-hour, SOx 24-hour, and SOx annual average concentrations are combined with the ambient background concentrations and compared to the Most Stringent Air Quality Standard (State and Federal standards). The PM10 and PM2.5 24-hour, and PM10 and PM2.5 annual average concentrations are compared to the Significant Change in Air Quality Concentration thresholds established by the South Coast AQMD, due to nonattainment status in the South Coast Basin.

State Standards

As discussed above for attainment pollutants, the CO 1-hour, CO 8-hour, NO_2 1-hour, NO_2 annual average, SOx 1-hour, SOx 3-hour, SOx 24-hour, and SOx annual average concentrations are combined with the ambient background concentrations and compared to the Most Stringent Air Quality Standard State standards. For nonattainment pollutants, the PM10 and PM2.5 24-hour, and PM10 and PM2.5 annual average concentrations are compared to the Significant Change in Air Quality Concentration thresholds established by the South Coast AQMD, due to nonattainment status in the South Coast Basin.

The maximum CO impact concentrations for 1-hour and 8-hour averages are 4,597.96 and 2,988.55 micrograms per cubic meter ($\mu g/m^3$), respectively. The maximum NO_2 impact (background plus project) concentrations for 1-hour and annual averages are 255.00 and 39.09 $\mu g/m^3$, respectively. The maximum SOx impact (background plus project) concentrations for 1-hour and 24-hour averages are 98.84 and 9.50 $\mu g/m^3$, respectively. The maximum PM10 project impact concentrations for 24-hour and annual averages are 0.05 and 0.02 $\mu g/m^3$, respectively. The maximum PM2.5 project impact concentrations for 24-hour and annual averages are 0.05 and 0.02 $\mu g/m^3$, respectively. As presented in Table 3, the modeling results are below all state criteria pollutant significance thresholds.

TABLE 3

Phillips 66 ULSD Project Heater B-401 State Significance Threshold Evaluation

Criteria Pollutant	**Averaging Period**	**Ambient Background Conc. (ug/m^3)**	**Project Calculated Conc. (ug/m^3)**	**Total Conc. (ug/m^3)**	**Most Stringent Air Quality Standard (ug/m^3)**	**Significant Change in Air Quality Conc. (ug/m^3)**	**Below Threshold?**
CO	1-hr	4597.60	0.36	*4597.96*	**23000**	1100	Yes
	8-hr	2988.44	0.11	*2988.55*	**10000**	500	Yes
NO_2	1- hr	254.88	0.12	*255.00*	**339**	20	Yes
	AAM	39.08	0.01	*39.09*	**57**	1	Yes
SO_2	1-hr	98.59	0.25	*98.84*	**655**	NA	Yes
	24-hr	9.46	0.04	*9.50*	**105**	NA	Yes
PM10	24-hr	62,00	*0.05*	62.05	50	**2.5**	Yes
	AAM	27.80	*0.02*	27.82	20	**1**	Yes
PM2.5	24-hr	52.20	*0.05*	52.25	35	**2.5**	Yes
	AAM	10.72	*0.02*	10.74	12	**1**	Yes

AAM = Annual Arithmetic Mean

Evaluation criteria differs from pollutant to pollutant and is dependent on the attainment status. The CO 1-hour, CO 8-hour, NO_2 1-hour, NO_2 annual average, SOx 1-hour, SOx 3-hour, SOx 24-hour, and SOx annual average concentrations are combined with the ambient background concentrations and compared to the Most Stringent Air Quality Standard Federal standards. For nonattainment pollutants, the PM10 and PM2.5 24-hour, and PM10 and PM2.5 annual average concentrations are compared to the Significant Change in Air Quality Concentration thresholds established by the South Coast AQMD, due to nonattainment status in the South Coast Basin. Evaluation criteria are *italicized* for clarity. Evaluation thresholds are **bolded** for clarity.

Federal Standards

As discussed above for attainment pollutants, the CO 1-hour, CO 8-hour, NO_2 1-hour, NO_2 annual average, SOx 1-hour, SOx 3-hour, SOx 24-hour, and SOx annual average concentrations are combined with the ambient background concentrations and compared to the Most Stringent Air Quality Standard Federal standards. For nonattainment pollutants, the PM10 and PM2.5 24-hour, and PM10 and PM2.5 annual average concentrations are compared to the Significant Change in Air Quality Concentration thresholds established by the South Coast AQMD, due to nonattainment status in the South Coast Basin.

The maximum CO impact concentrations (background plus project) for 1-hour and 8-hour averages are 4,597.96 and 2,988.55 micrograms per cubic meter ($\mu g/m^3$), respectively. The maximum NO_2 impact concentrations (background plus project) for 1-hour and annual averages are 160.23 and 39.09 $\mu g/m^3$, respectively. The maximum SOx impact concentrations (background plus project) for 1-hour, 3-hour, 24-hour, and annual averages are 31.80, 31.67, 9.50, and 3.59 $\mu g/m^3$, respectively. For the nonattainment PM10 pollutant, the maximum PM10 project impact concentrations for 24-hour and annual averages are 0.05 and 0.02 $\mu g/m^3$, respectively. For the nonattainment PM2.5 pollutant, the maximum PM2.5 project impact concentrations for 24-hour and annual averages are 0.05 and 0.02 $\mu g/m^3$, respectively. The modeling results are below all federal criteria pollutant significance thresholds as presented in Table 4.

Based on the results of air quality modeling, the ambient air quality analysis for charge Heater B-401, the only stationary combustion sources associated with the ULSD Project, indicates that the ULSD Project results in no significant changes in air quality and no exceedances of any state or federal air quality standards for CO, NO_2, SOx, PM10, or PM2.5.

TABLE 4

Phillips 66 ULSD Project Heater B-401 Federal Significance Threshold Evaluation

Criteria Pollutant	Averaging Period	Ambient Background Conc. (ug/m^3)	Project Calculated Conc. (ug/m^3)	Total Conc. (ug/m^3)	Most Stringent Air Quality Standard (ug/m^3)	Significant Change in Air Quality Conc. (ug/m^3)	Below Threshold?
CO	1-hr	4597.60	0.36	*4597.96*	**40000**	1100	Yes
	8-hr	2988.44	0.11	*2988.55*	**10000**	500	Yes
NO_2	1- hr	160.11	0.12	*160.23*	**188**	20	Yes
	AAM	39.08	0.01	*39.09*	**100**	1	Yes
SO_2	1-hr	31.55	0.25	*31.80*	**197**	NA	Yes
	3-hr	31.55	0.12	*31.67*	**1314**	NA	Yes
	24-hr	9.46	0.04	*9.50*	**105**	NA	Yes
	AAM	3.47	0.01	*3.48*	**80**	NA	Yes
PM10	24-hr	62.00	*0.05*	62.05	150	**2.5**	Yes
	AAM	27.80	*0.02*	27.82	NA	**1**	Yes
PM2.5	24-hr	52.20	*0.05*	52.25	35	**2.5**	Yes
	AAM	10.72	*0.02*	10.74	15	**1**	Yes

AAM = Annual Arithmetic Mean

Evaluation criteria differs from pollutant to pollutant and is dependent on the attainment status. The CO 1-hour, CO 8-hour, NO_2 1-hour, NO_2 annual average, SOx 1-hour, SOx 3-hour, SOx 24-hour, and SOx annual average concentrations are combined with the ambient background concentrations and compared to the Most Stringent Air Quality Standard Federal standards. For nonattainment pollutants, the PM10 and PM2.5 24-hour, and PM10 and PM2.5 annual average concentrations are compared to the Significant Change in Air Quality Concentration thresholds established by the South Coast AQMD, due to nonattainment status in the South Coast Basin. Evaluation criteria are *italicized* for clarity. Evaluation thresholds are **bolded** for clarity

Response 1-44

This comment lists the South Coast AQMD's mass daily operational significance thresholds for criteria pollutants. The thresholds cited in this comment are consistent with those provided in Table 3.3-6 of the 2014 Draft EIR; therefore, no further response is necessary.

In this comment it is asserted that lead emissions were not calculated in the Draft EIR. Further, it is asserted that the following operations produce lead emissions: heater, hydrogen production, electricity demand, steam production and truck transport. The potential for lead emissions from the proposed project was considered in the analysis for the ULSD Project, but no lead emissions were identified, as explained in the following paragraphs.

With regard to the heaters and steam production, the refinery does not operate coal-fired, residual gas or wood burning industrial boilers or heaters that would generate lead emissions[7]. With regard to the pre-project and replacement Heaters (B-201 and B-401, respectively), for example, the HRA prepared for the proposed project used emission factors based on source tests (see EIR Appendix C). As shown in Appendix C, Attachment A, Table A-1, pre-project lead emissions were non-detectable. Similarly, Appendix C, Attachment A, Table A-2 shows that post-project lead emissions were also non-detectable. Therefore, practically speaking, it can be concluded that there were no lead emissions from either the pre-project Heater B-201 or the post-project Heater B-401.

The project does increase hydrogen consumption, thereby requiring an increase in hydrogen production. For the sake of the EIR analysis, the additional hydrogen is assumed to be provided by another company, Air Products, as the hydrogen plants at Wilmington operate at full capacity. The Air Products Hydrogen Plant primarily uses natural gas to produce hydrogen. Lead is not present in natural gas and so the use of natural gas to produce hydrogen would not generate lead emissions. In addition, hydrogen could also be produced from refinery gas, LPG, light naphtha, and heavy naphtha. Lead is also not present in these potential alternate feedstocks to the hydrogen plant. As a result, lead emissions are not generated from the production of hydrogen that will result from this project. The EIR prepared for the Air Products Hydrogen Plant included the evaluation of toxic air contaminants (City of Carson, 1998). A Health Risk Assessment was included as part of that EIR and evaluated the health impacts associated with exposure to toxic air contaminant emissions. The Health Risk Assessment concluded that there were no lead emissions associated with the operation of the hydrogen plant. Further, the South Coast AQMD requires that emissions of certain toxic air contaminants, including lead, be reported as part of annual emissions reports that stationary sources file with the South Coast AQMD. Based on the annual emission reports submitted to the South Coast AQMD by Air Products and available on the South Coast AQMD web page, lead was not a toxic air contaminant emitted from the Air Products Hydrogen Plant during either the baseline period (2002-2003) or post-project period (2006-2008). Therefore, since lead is not emitted from the Air Products hydrogen plant, no increase in lead emissions occurred due to increased hydrogen production from the Air Products Hydrogen Plant associated with the ULSD Project.

Increase in electricity demand from the proposed project would result in an increase in emissions from the local power utility source. Power utilities within the South Coast AQMD's area of jurisdiction are required to operate on natural gas, which is also generally the case in other air districts in California. Therefore, industrial boilers in California that may be used to generate electricity for the proposed project are not coal-fired, residual gas or wood burning industrial boilers. Because utility boilers at electricity generating facilities in the district and throughout most of California are required to operate on natural gas, therefore, since lead is not present in natural gas no lead emissions would be expected. Similarly, with regard to electrical utilities that use gas turbines to generate electricity, according to the U.S. EPA[8], there are no lead emission factors applicable to the operation of natural gas-fired turbines because lead is not present in

[7] Pursuant to U.S. EPA's Report on "Uncontrolled Emission Factors for Criteria Pollutants" (https://www.epa.gov/air-emissions-inventories)
[8] U.S. EPA's "Stationary Gas Turbines" http://www.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

natural gas, so lead emissions would not be expected as a result of an increase in electricity generation.

With regard to potential lead emissions from steam generation, as explained in detail in the Draft EIR (pages 3-36 thru 3-40), the refinery operates a steam system flow that allows an integration of the different steam pressure systems resulting in no additional steam generation or increased operation of the boilers or heaters to support Unit 90. See also Responses: 1-3, 1-78, 1-79, and 1-80. In addition, to ensure there is no change in steam production associated with the operation of Unit 90 before and after the project, mitigation measure AQ-1 has been imposed requiring monitoring and reporting fuel usage on an annual basis for a period of five years. For additional information on mitigation measure AQ-1, refer to Response 1-81.

With regard to truck transport, trucks are used to transport aqueous ammonia and additional catalyst. These loads are transported by heavy- or heavy-heavy-duty diesel trucks operating on diesel fuel. Diesel fuel does not contain lead[9], so no lead emissions are being generated by the combustion of the diesel trucks as a result of the ULSD Project. The ULSD Project did not require additional workers so employee commute trips did not increase. However, like diesel, gasoline also does not contain lead.

Therefore, as indicated above, the 2014 Draft EIR did consider that the proposed project had the potential to generate lead emissions. However, using source test data for the heaters, it was demonstrated that lead emission factors for both the pre-project and post-project operations were non-detectable or were not available. In addition, other sources cited in the comment do not combust fuels that contain measurable quantities of lead. Therefore, the comment that lead emissions were not calculated and that the Draft EIR is deficient is without merit. Further, the commenter did not provide any data or other information supporting the assertion that the proposed project has the potential to generate lead emissions.

Response 1-45

This comment cites the South Coast AQMD's 1993 Handbook to argue that post project emissions should be based on the highest daily emissions and not the annual average day based on annual averages in the middle of a recession. The 1993 Handbook makes no references to quantifying emissions during a recession. With regard to the influence of the recession on post-project emissions, refer to Response 1-53.

When the South Coast AQMD's Handbook was adopted in 1993, its primary purpose was to provide guidance to other public agencies for quantifying direct emissions from a project. For comparison to the daily significance thresholds, quantification of project emissions should be based on the maximum daily emissions from the equipment that is part of a proposed project. This is the maximum operations allowed under the permit and is not tied to activity levels based on a recession or other factors. Once quantified, the Handbook recommended that the direct emissions from all project components then be compared to the South Coast AQMD's significance thresholds. As a result, the analysis of air quality impacts in the 2014 Draft EIR for

[9] http://www.air-quality.org.uk/26.php

the ULSD Project identifies peak daily emissions for new or modified equipment, as well as for increased usage of existing equipment, that are part of the proposed project. Reasonably foreseeable indirect source emissions should also be included in an air quality analysis along with direct emissions impacts.[10] Generally, much of the information in the 1993 Handbook on analyzing air quality impacts has been updated. The primary guidance provided by the South Coast AQMD for analyzing air quality impacts can be found online at: http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook.

Potential direct emission impacts from the project for new or modified equipment are based on maximum permit limits, or potential to emit (PTE) using best available control technology (BACT), which is considered to be the lowest achievable emission rate (LAER). For example, on page 3-34 of the Draft EIR it is clearly stated that emissions from Heater B-401 (new heater) are based on the maximum potential to emit from the heater as estimated from the South Coast AQMD permit application. Therefore, there is no reason to examine several years of post-project daily emissions as suggested in this comment. Doing so would result in using lower emissions for the post-project period. Similarly, a recession has no effect on this permitted maximum potential to emit used in the analysis. Thus the proper post-project emissions were evaluated.

The post-project period also included maximum emissions from new fugitive components including pumps, compressors, valves, flanges, and process drains. The emission estimates in the 2014 Draft EIR are based on the actual as-built changes in fugitive component counts, including emission increases from the addition of new components and emission decreases associated with removal of older components. Fugitive components are subject to best available control technology (BACT) requirements, as applicable. BACT for fugitive components specifies types of valves, seals, pressure relief devices, etc., with associated emission factors that represent the maximum (peak) emissions from the regulated fugitive component. Specific emission factors for BACT for each type of fugitive component were provided by South Coast AQMD permit processing engineers or are included in the South Coast AQMD's BACT Guidelines[11]. The analysis of emissions from fugitive components relies on BACT determinations provided by South Coast AQMD permit engineers not only for consistency, but also because these are the only reliable emission factors available. To ensure that the Refinery complies with BACT limits for fugitive components, it is required to monitor fugitive components under South Coast AQMD Rule 1173 and maintain a database of components by unit.

Other emissions sources cited in the comment are considered to be indirect sources, that is, they were not physically modified as part of the project. CEQA Guidelines §15064(d)(2) states that,

[10] This EIR uses the term indirect emission sources to refer to those items that can cause CEQA indirect physical changes. CEQA Guidelines §15064(d)(2) provides: "An indirect physical change in the environment is a physical change in the environment which is not immediately related to the project, but which is caused indirectly by the project. If a direct physical change in the environment in turn causes another change in the environment, then the other change is an indirect physical change in the environment." Under CEQA, indirect sources can include both stationary and mobile sources of emissions. "Indirect sources" in this CEQA context are not synonymous with or restricted to "indirect emissions" as defined under the Clean Air Act (i.e., "a facility . . . which attracts . . . mobile sources of pollution.")

[11] Accessed at http://www.aqmd.gov/home/permits/bact/guidelines

"An indirect physical change in the environment is a physical change in the environment which is not immediately related to the project, but which is caused indirectly by the project. If a direct physical change in the environment in turn causes another change in the environment, then the other change is an indirect physical change in the environment." Permits and permit conditions from indirect emission sources would not change in the cases of hydrogen or electricity production as a result of the ULSD Project since hydrogen and electricity are purchased from third parties (Air Products for hydrogen and the Los Angeles Department of Water and Power for electricity). The ULSD Project would use only a small portion of the hydrogen or electricity generated by the third party; therefore, the maximum potential to emit of these third party facilities is not relevant to analysis of the ULSD Project. Further, in the case of the Air Products Hydrogen Plant, the facility has undergone its own EIR and its environmental impacts have been previously evaluated. On a peak day, the ULSD Project would use one to four percent of the total Air Products hydrogen production and the ULSD EIR estimates the emissions associated with producing one to four percent of the Air Products hydrogen production (see Response 1-59 for a further discussion of this issue). The ULSD EIR does not attribute all emissions from peak operation of the Air Product hydrogen plant to the ULSD Project, and nor should it. It would not be appropriate to calculate the maximum potential to emit for these third party facilities, as hydrogen and electricity generated by these indirect sources are used by other facilities in addition to the Wilmington Refinery. Consequently, assigning all peak daily emissions from indirect sources to the ULSD Project is not accurate, is misleading, and obscures the actual contribution of indirect emission impacts from the ULSD Project. Instead, indirect source emissions attributed to the project are based on the project's demand for hydrogen and electricity, that is, the incremental increase in operation of indirect sources caused by the ULSD Project during the post-project period. Only emissions from the incremental increase in operations of the indirect sources caused by the ULSD Project should be added to the direct impacts from the project.

Table 5 below contains a summary of the data used to calculate emissions in the Draft EIR. As shown in Table 5, the peak/maximum equipment operation was used for all emission calculations, except for the estimated hydrogen production. Emission factors are based on permit limits, rule limits or prohibitions, physical constraints based on equipment design, and published sources, depending on availability and relevance. The Final EIR has been revised to include the peak hydrogen use, as opposed to the average hydrogen use. For more details on the methodologies to determine emissions from the replacement heater, refer to Responses to comments 1-62, 1-63, 1-64, 1-66, 1-67, 1-69, and 1-70. Relative to methodologies to determine emissions from hydrogen production, refer to Responses to comments 1-53, 1-54, 1-56, 1-58, 1-59, and 1-61. Relative to methodologies to determine electrical demand, refer to Responses to comments 1-74, 1-75, 1-76, and 1-77. Relative to methodologies to determine steam production, refer to Responses to comments 1-3, 1-78, 1-79, and 1-80.

TABLE 5

Project Emission Calculation Methodology

Emissions	Calculation Methodology	Assumptions Used in Draft EIR	Data
Fugitive Emissions	Engineering estimates	Actual change in components multiplied by South Coast AQMD emission factors	Peak
Replacement Heater B-401	Maximum potential to emit	SOx, NOx and CO based on South Coast AQMD permit limits at maximum firing	Maximum permitted levels
	South Coast AQMD Emission Factors	ROG, PM10 and PM2.5 based on South Coast AQMD emission factors for natural gas at maximum firing	Peak
Hydrogen Production	Emission Factors from Air Products EIR	Hydrogen demand for Units 89 and 90 combined was calculated as the difference between 2002-2003 demand and 2006-2008 demand. The increase was attributed to Unit 90 solely	Draft EIR used average actual daily emissions. The peak daily emissions have been included in the Final EIR.
Electricity	Emission Factors from South Coast AQMD CEQA Handbook	Change in peak electrical demand pre and post project. Includes installation of new pumps, fans, air coolers, and reactivation of 200 hp recycle gas compressor and assumes they operate 24/7.	Peak
Vehicle Emissions	EMFAC2002	The Draft EIR assumed 5 total trucks on a peak day (1 ammonia delivery and 4 for catalyst change out). The total trucks has been revised to 1 truck for ammonia delivery and 1 truck for sulfur delivery in the Final EIR(1)	Peak
Storage Tank	U.S. EPA TANKS model	Based on maximum throughput from South Coast AQMD permit	Maximum permitted levels
Steam Demand	Engineering Design	No increase in 400 psi stream; so no increase in emissions	Confirmed with monitoring data from letdown valve on steam system

(1) Based on Phillips 66 records for disposing of spent catalyst, there has been no increase in peak daily catalyst trucks associated with the project. Prior to the ULSD Project, the most catalyst that could be moved from Unit 90 was three trucks per day. Even though the total amount of catalyst used in Unit 90 has increased due to the ULSD Project, the refinery is limited to three trucks per day that can be loaded with spent catalyst from Unit 90 due to space limitation. Therefore, the ULSD Project has resulted in no increase in trucks for catalyst change out in a peak day.

Response 1-46

In this comment, it is asserted that emissions were underestimated because the Draft EIR's calculations only focused on Unit 90 and new equipment, but did not include existing equipment required to support Unit 90, specifically the equipment necessary to handle the increase in hydrogen sulfide (H_2S) and sulfur. The comment is correct that the Draft EIR did not estimate emissions associated with an increase in sulfur handled at the refinery as a result of the proposed project. These emissions associated with the increase sulfur generation are estimated below and included in the Final EIR. The emissions from Unit 90, as well as indirect emissions for other support equipment associated with the ULSD Project (e.g., hydrogen and electricity use) have been included in the Final EIR, but do not change the conclusions in the Draft EIR or cause the project to exceed the significance thresholds.

Sulfur removed from refined products at the Wilmington Plant is converted to hydrogen sulfide (H_2S). The H_2S is processed in two ways: first, in the Sulfuric Acid Plant, where it is used to manufacture and regenerate sulfuric acid, which is used on-site in the Alkylation Unit; and, second, in the Sulfur Recovery Plant, where it is converted into elemental sulfur, which is trucked off-site and sold as a co-product. The H_2S processed in the Acid Plant results in a net increase in production of steam for use in the refinery and makes an intermediate product needed for producing alkylate. The amount of H_2S processed in the Acid Plant is variable because it is determined by the need for sulfuric acid production; therefore, the most conservative analysis is to assume all incremental H_2S generated by the ULSD Project is processed in the Sulfur Recovery Plant.

The ULSD Project lowers sulfur in diesel fuel from approximately 500 ppmw to 5 ppmw. Based on the material balance for the Unit 90 ULSD Project, design feed to the unit is 402,690 lb/hr, therefore:

Incremental Sulfur Generated = 402,690 lbs/hr x (500 ppm -5 ppm)/1,000,000 ppm = 199.3 lbs/hr or 4,784 lbs/day of Sulfur produced due to the ULSD Project

Incremental H_2S Generated = 4,874 lbs/day of Sulfur x 34 (lb/lb-mole) H_2S/32 (lb/lb-mole) Sulfur = 5,083 lbs/day or 211.8 lbs/hr H_2S produced due to the ULSD Project

Based on historical data provided by Phillips 66 for utility use by the Sulfur Recovery Plant, the potential increase in utility usage based on the incremental increase in sulfur and H_2S generated, is calculated as follows:

Fuel Gas = 0.0041 MSCF/lb H_2S x 5,083 lb H_2S/day = 20.8 MSCFD
Steam = 0.0142 M lb/lb H_2S x 211.8 lb/hr = 3,007 lb/hr
Electricity = 0.3 kW-hr/lb H_2S x 5,083 lb/day = 1,524 kW-hr/day
Sulfur truck increase =4,784 lb Sulfur/day x 365 day/year x 1 Long Ton/2,240 lb x 1 truck/22 Long Ton = 35.4 trucks/yr

The ULSD Project also increased production of sour water from Unit 90, but the incremental H_2S in the sour water is included in the total incremental H_2S calculated above. The emissions associated with fuel gas, additional steam, additional electricity, and additional sulfur trucks from the theoretical increase in the Sulfur Recovery Plant are estimated below.

Fuel Gas at Sulfur Recovery Plant

Incremental emissions associated with the increase in fuel gas used at the Sulfur Recovery Plant were calculated using the South Coast AQMD's standard emission factors for the combustion of natural gas in heaters as described in the Annual Emissions Report Program. The potential increases in emissions are calculated in Table 6 and have been added to the Final EIR.

TABLE 6

Sulfur Recovery Plant Fuel Gas Incremental Emissions

	CO	VOC	NOx	SOx	PM10	PM2.5[(2)]
Emission Factor (lbs/mmscf)[(1)]	35	7	99.2	0.83	7.5	7.5
Emissions from Increased Fuel Gas 20.8 mscf (lbs/day)	0.73	0.15	2.06	0.02	0.16	0.16

(1) Source: South Coast AQMD Default Emission Factors from Annual Emissions Report Program for CO, VOC, SOx, and PM10. NOx Emission Factor is from RECLAIM monitoring data.
(2) PM2.5 emissions assumed to be equivalent to PM10 emissions.

Steam

The Sulfur Recovery Plant requires heat in the form of steam to convert H_2S to sulfur. The Sulfur Recovery Plant uses 400 psi steam. The 400 psi steam is consumed at the Sulfur Recovery Plant and the steam from the Sulfur Recovery Plant does not feed the 150 psi steam system at the Refinery. (This is a different configuration from Unit 90, which draws steam from the 400 psi steam system but then ejects steam back into the header for the 150 psi steam system.) The above calculations show that a maximum of an additional 4,784 lbs/day of sulfur may be generated due to the ULSD Project, which would require an additional 3,007 lbs/hr of steam.

The increased boiler firing due to the incremental increase in H_2S processed at the Sulfur Recovery Plant is calculated as follows:

Increased boiler firing = [3,007 lb/hr steam x (1204.6 – 195.2) Btu/lb]/0.8 =
3.8 mmbtu/hr

Where:
Enthalpy of 400 psi saturated steam = 1204.6 Btu/lb
Enthalpy of boiler feedwater at 227°F = 195.2 Btu/lb (heated with recovered energy)
Boiler efficiency = 80%

The increased fuel use = 3.8 mmBtu/hr x scf/1528.6 Btu x 24 hr/day = 0.06 mmscf/day

Where:
Average high heat value of refinery fuel gas (post project) = 1528.6 Btu/scf

Steam can be supplied by several different existing boilers and the Cogeneration Plant pursuant to existing permit conditions and the emissions will vary depending on which combination of equipment is used. The potential incremental increase in emissions associated with additional steam used at the Sulfur Recovery Plant is calculated using a "worst-case" and normal emission increase. On a worst-case basis, steam generated from Boiler 4 will produce the most emissions because it is the oldest boiler at the refinery (and has the highest allowable emission limits). On a more routine basis, it is expected that steam will be generated from Boiler 7. The estimated emission increases associated with the increased steam demand are provided below in Table 7.

TABLE 7

Incremental Emissions from Increased Steam Demand at the Sulfur Recovery Plant

Worst-Case Emissions Increase - Boiler 4			Typical Emissions Increase - Boiler 7		
Pollutant	**Emissions Factor (lb/mmscf)**	**Total Emissions (lbs/day)**	**Pollutant**	**Emissions Factor (lb/mmscf)**	**Total Emissions (lbs/day)**
CO	84.0	5.04	CO	84.0	5.04
VOC	11.0	0.7	VOC	11.0	0.7
NOx	295.2	17.71	NOx	22.2	1.33
SOx	6.0	0.36	SOx	6.0	0.36
PM10	7.5	0.45	PM10	7.5	0.45
PM2.5	7.5	0.45	PM2.5	7.5	0.45

Electricity

Incremental emissions associated with increased electricity at the Sulfur Recovery Plant were calculated using the same emission factors used for the increase in electricity associated with new equipment. The emission factors used were based on the South Coast AQMD CEQA Air Quality Handbook, Table A9-11-B (South Coast AQMD, 1993). The potential increases in emissions are calculated in Table 8 and have been added to the Final EIR.

TABLE 8

Sulfur Recovery Plant Electricity Generation Emissions

	CO	VOC	NOx	SOx	PM10	PM2.5[2]
Emission Factor (lbs/MW-hr)[1]	0.2	0.01	1.15	0.12	0.04	0.04
Emissions from Sulfur Recovery Plant Electricity (lbs/day)	0.3	0.0	1.7	0.2	0.1	0.1

(1) Source: South Coast AQMD CEQA Air Quality Handbook, Table A9-11-B (South Coast AQMD, 1993).
(2) PM2.5 emissions assumed to be equivalent to PM10 emissions.
(3) Electricity = 0.3 kW-hr/lb H_2S x 5,083 lb/day = 1524 kw-hr/day
1524 kw-hr/day x (1 day/24 hr) x (1 MW/1,000 kw) = 0.06 MWh

Sulfur Trucks

Emissions associated with the increase in sulfur trucks were calculated using the same emission factors used for other delivery trucks in the EIR using on-road mobile emission factors from California ARB EMFAC2002 Scenario Year 2004 (Model Years A11965 to 2004). The potential increases in emissions are calculated in Table 9 and have been added to the Final EIR.

TABLE 9

Emissions from Increase in Sulfur Trucks

Vehicle Type	CO Emissions Factor (lb/mile)[1]	VOC Emission Factor (lb/mile)[1]	NOx Emission Factor (lb/mile)[1]	SOx Emission Factor (lb/mile)[1]	PM10 Emissions Factor (lb/mile)[1]	PM2.5 Emissions Factor (lb/mile)[1]
Heavy Diesel Trucks	0.02309	0.003148	0.029607	0.000243	0.000519	0.000519

	Parameters			Peak Day Emissions (lbs/day)					
Source	Number of Vehicles	Total Number of Trips	Distance Traveled (miles)	CO	VOC	NOx	SOx	PM10	PM2.5
Sulfur Trucks	1	1	3	0.07	0.01	0.09	0.00	0.00	0.00

1) On Road Mobile Emission Factors from California ARB EMFAC2002 Scenario Year 2004 (Model Years A11965 to 2004); PM2.5 emissions assumed to be equivalent to PM10 emissions
2) Increase in sulfur trucks is calculated to be a maximum of 35.4 trucks per year. Peak day assumes 1 sulfur truck

Table 10 summarizes the estimated peak increase in emissions associated with the increased use of the Sulfur Recovery Plant due to the ULSD Project. As shown in Table 10, the peak emission increases due to increased operation of the Sulfur Recovery Plant are small. Nonetheless, these emission increases have been included in the Final EIR. Their inclusion, however, does not alter the conclusions of the analysis: no project emissions exceed the applicable thresholds of significance.

TABLE 10

Estimated Sulfur Recovery Plant Incremental Emissions Associated with the ULSD Project (lbs/day)

	CO	VOC	NOx	SOx	PM10	PM2.5[(2)]
Emissions from Increased Fuel Gas 20.8 mscf	0.73	0.15	2.06	0.02	0.16	0.16
Emissions from Increased Steam Use at Sulfur Recovery Plant	5.04	0.7	1.33-17.71	0.36	0.45	0.45
Emissions from Sulfur Recovery Plant Electricity	0.3	0.0	1.7	0.2	0.1	0.1
Emissions from Sulfur Trucks	0.07	0.01	0.09	0.0	0.0	0.0
Total Sulfur Recovery Plant Emissions from ULSD Project	6.14	0.86	5.18-21.56	0.58	0.71	0.71

Response 1-47

This comment states that the Draft EIR used the years 2002 to 2003 as the baseline years for the heater, hydrogen production, and steam production, but does not disclose the baseline for other emissions sources. It is assumed that other emissions sources refer to fugitive emissions, storage tank 331, and truck trips. For those sources, the increase in emissions was calculated directly from the increase in emission sources associated with the project, i.e., the increase in fugitive emissions was calculated based on the actual number of fugitive components associated with the project (see Draft EIR, page B-2). The truck trips associated with the project were based on a peak day estimate that five daily delivery trucks would be required: one ammonia delivery truck (one ammonia truck per year); and four trucks per day when catalyst replacement is required in Unit 90 (the life expectancy of the catalyst was expected to be two to three years, so catalyst replacement was estimated to occur every two to three years for approximately 14 days). Since the publication of the 2014 Draft EIR, operational data associated with Unit 90 have been fully reviewed. The catalyst associated with Unit 90 has not required replacing since the initial operation began; therefore, the catalyst in Unit 90 requires changing more than every 10 years. Further, based on Phillips 66 records for disposing of spent catalyst, there has been no increase in peak daily catalyst trucks associated with the ULSD Project. Prior to the ULSD Project, the most catalyst that could be moved from Unit 90 was three trucks per day. Even though the total amount of catalyst used in Unit 90 has increased due to the ULSD Project, the refinery is limited to three trucks per day that can be loaded with spent catalyst from Unit 90 due to space limitations. Therefore, the ULSD Project has resulted in no increase in trucks for catalyst change out in a peak day and the Final EIR has been revised to reflect the actual change in truck trips.

Emission increases in the Draft EIR were then estimated using the number of trucks and the CARB emission factors for trucks (see Draft EIR, page B-6). On page 3-33 of the Draft EIR it is clearly stated that, "The baseline for the ULSD Project was Refinery operations in 2002-2003 (pre-project), which reflects the existing environmental setting when the environmental analysis development of the ULSD Project began." Only one baseline (pre-project period) is identified throughout the document. In some of the tables in Appendix B, baseline emissions are marked as pre-project. To avoid any confusion, the Final EIR provides further clarification that pre-project emissions mean the years 2002 to 2003.

Comment 1-47 infers that emissions from Tank 331 are underestimated. Tank 331 existed and was permitted for operation but was idle during the baseline period, and was put back into jet/diesel fuel service as part of the ULSD Project. As stated on page 3-34, "Under the baseline conditions, Tank 331 was assumed to have no emissions as the tank was not in service." Post project emissions from the tank were based on maximum daily throughput conditions. Table 3.3-7 of the 2014 Draft EIR shows the total emissions from Tank 331 and Appendix B provides more detailed information on quantifying post-project emissions from this source. Tank 331 is an existing permitted unit that was not physically modified by the proposed project (indirect source) and all emissions associated with it have been accounted for in the emissions analysis for the ULSD Project, which is considered to be a conservative analysis. The language in the Final EIR has been added to indicate that the emissions from Tank 331 are based on the maximum allowable emissions under South Coast AQMD permit conditions that include the type of tank (external floating roof tank), size of the tank, characteristics of the material stored (unifined heavy cat gas), the tank volume (3,444,000 gallons), and the number of turnovers (14.24 per year).

Response 1-48

The comment states that the 2002-2003 baseline selected may be reasonable, but that the Draft EIR included insufficient explanation and data to show that this period was representative. Further, the comment claims that a longer period of at least 10 years is necessary to confirm and establish actual operations in the baseline years. This comment provides no support for the statement that a longer period of 10 years is necessary to establish a baseline. Indeed, there is no such requirement in CEQA or CEQA case law.

The Supreme Court's decision in *CBE v. SCAQMD* guided the preparation of the EIR. The Supreme Court noted statements of the South Coast AQMD and Phillips 66 that refinery operations are complex and variable. 48 Cal. 4th at 327. The Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence. 48 Cal. 4th at 327, 328. The Supreme Court also stated that, in preparing the EIR, the South Coast AQMD is not required to use the same measurement method as used in the Negative Declaration. 48 Cal. 4th at 328.

Using a longer baseline period may be appropriate for some projects. For the Phillips 66 ULSD Project, however, the baseline and the post project period for comparison were selected to avoid other events and refinery changes that would have obscured the emissions consequences of the project. To identify the effects of the ULSD Project, it was necessary for the South Coast AQMD to compare baseline (pre-project) and post-project periods that were not influenced by other, independent changes at the refinery. In particular, in November 2001, flue gas recirculation was added to Boiler 7, reducing NOx emissions from about 85 ppm to about 46 ppm (a 46 percent reduction, based on RECLAIM data). If a longer pre-project period were used for the baseline, the baseline emissions would appear to be substantially higher because the baseline would have included many months when Boiler 7 was operating without the added controls. SCR was added in December 2008, reducing NOx from 46 ppm to 11 ppm (an 82 percent reduction). If a longer post-project period were used, the post-project period would appear to have substantially lower emissions because it would include many months of operation of Boiler 7 at very low emissions rates due to the SCR unit. The combined effect of using a higher baseline and lower post-project emissions would be to shrink the emissions attributed to the project. The baseline pre-project and post-project periods were chosen to avoid the change in NOx emissions due to these two refinery modifications, which were unrelated to the ULSD Project. To avoid inappropriate influences from these and other independent projects, the South Coast AQMD had to use an approximately two-year period for the pre-project baseline and the post-project period.

The comment states that, "to support a selected baseline, one generally needs to supply a longer period of record, at least 10 years, to confirm routine actual operations in the baseline years." This statement is contrary to CEQA guidelines Section 15125(a) that states the baseline is generally "the physical environmental conditions in the vicinity of the project as they exist at the time the notice of preparation is published . . ."As explained above, using a 10-year period to determine the baseline would have been misleading. In particular, in November 2001, flue gas recirculation was added to Boiler 7, reducing NOx emissions from about 85 ppm to about 46 ppm (a 46 percent reduction, based on RECLAIM data). If a longer pre-project period were used for the baseline, the baseline emissions would appear to be substantially higher because the baseline would have included many months when Boiler 7 was operating without the added controls.

Response 1-49

Comment 1-49 asserts that the calculated pre-project Heater (Heater B-201) emissions were based on peak daily emissions. This assertion is made in more detail in comment 1-69; therefore, refer to Response to Comment 1-69, as well as Response 1-9.

Comment 1-49 then questions whether pre-project emissions from other sources, for example hydrogen production, steam production, and increased electricity demand, may have been based on peak emissions. With regard to impacts from increased hydrogen production, refer to Responses to Comments 1-53, 1-54, 1-55, 1-56, 1-58, 1-59, and 1-61. With regard to increased steam production, refer to Responses to comments 1-3, 1-78, 1-79, and 1-80. With regard to increased demand for electricity, refer to Responses to comments 1-74, 1-75, 1-76, and 1-77.

Response 1-50

This comment states that Draft EIR Table 3.1-13 (it is assumed that the comment refers to Table 3.1-3), which shows total refinery emissions for CO, NOx, VOC, SOx and PM10 over the period 2000 to 2013, is not adequate to support 2002 to 2003 as the baseline years for the individual processes. As lead agency for permit application projects such as the ULSD Project, the South

Coast AQMD often includes historical emissions information for existing facilities to show fluctuations or emission trends over time. Since a CEQA environmental analysis occurs before a project is built and in operation, post-project emissions data are not typically available. Since the ULSD Project became operational in 2006, pre-project and post-project refinery emissions data are available and, therefore, are included in Table 3.1-3. Regardless, the pre-project data on this table is only one aspect used to describe the environmental setting. Refer to Subsection 3.3.2.1 in the Draft and Final EIRs, as well as Response to Comment 1-48, for the rationale regarding why the years 2002 to 2003 were selected to establish the emissions baseline for the ULSD Project. For additional detailed information regarding establishing the baseline for the ULSD Project, refer to Response to Comments: 1-3, 1-7, 1-9, 1-10, 1-47, 1-53, 1-69, and 1-73.

Finally, it should be noted that Table 3.1-3 of the 2014 Draft EIR provides useful information that demonstrates how refinery emissions fluctuate over time due to a variety of factors. The table also shows that the ULSD Project has had no discernible effect on overall refinery emissions. However, conclusions that the project's emission impacts are less than significant are not based on Table 3.1-3 of the 2014 Draft EIR; they are based on the analysis in the 2014 Draft EIR that combined emissions from the specific project components do not exceed the applicable air quality significance thresholds.

Response 1-51

This comment again summarizes points made in previous summary comments and made in more detail in later comments. The South Coast AQMD again disagrees with these repeated assertions as explained as follows. The comment asserts that project emissions are underestimated. Refer to Responses 1-46, 1-54, 1-59, 1-60, 1-67, 1-70, and 1-77. The comment also asserts that NOx emission impacts are significant because incorrect methods were used to determine pre-project emissions. Refer to Response to Comments 1-44, 1-62, 1-63, 1-69, 1-76, and 1-78. The comment states that incorrect methods were used to determine post-project emissions. Refer to Response to Comments 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76.

Response 1-52

This is a summary comment that summarizes the more detailed comments provided in Comments 1-53 through 1-60. The comment notes that the ULSD Project resulted in increased demand for hydrogen, which is used to remove sulfur from the feedstock to the diesel hydrotreater, Unit 90. The comment then goes on to assert that emissions from increased hydrogen production were underestimated for the following four reasons (actually #3 is listed twice so there are five reasons asserted here): (1) the analysis used the wrong post project period – see Responses 1-53, 1-54, and 1-55; (2) the analysis used the wrong measure of significance – see Response 1-56; (3) the analysis used annual averages instead of maximum potential to emit – see Response 1-54; (4) the analysis improperly adjusted hydrogen production emission factors to exclude flaring – see Responses 1-59 and 1-60 – and indirect sources of emissions – see Response 1-58; and (5) the analysis inappropriately combined hydrogen demand for Units 89 and 90 – see Responses 1-54 and 1-61.

It also should be noted that the majority of emissions associated with hydrogen production to support the ULSD Project already have been reviewed and mitigated under CEQA. Most of the additional hydrogen required to support the ULSD Project has been and will continue to be supplied by a third party, Air Products (see Draft EIR p. 3-35). In 1998, the City of Carson certified a final environmental impact report that analyzed the environmental impacts associated with construction and operation of the hydrogen plant that Air Products proposed to build in the City of Carson, CA (City of Carson 1998). The Air Products Hydrogen Plant was designed to provide hydrogen to local refineries including, the former ARCO Carson Refinery (now owned by Marathon and operated as Tesoro), the former Texaco Refining and Marketing, Inc. Los Angeles Refinery (now owned by Marathon and operated as Tesoro), and Phillips 66 (the location of the ULSD Project) and potentially other refineries in the vicinity. With one exception, transportation of hazardous materials, the operational impacts associated with the Air Products Carson Hydrogen Plant were found to be less than significant, or less than significant after mitigation. Air quality mitigation included compliance with regulatory programs requiring use of BACT and provision of offsets. To the extent that the hydrogen for the ULSD Project is produced at the Air Products Carson Hydrogen Plant and within the 96 million standard cubic feet per day (mmscfd) production rate evaluated in the 1998 Final EIR, the emissions associated with hydrogen production have already been analyzed under CEQA and mitigation was required to reduce the impacts to less than significant; therefore, they do not need to be reviewed in the ULSD EIR and no further mitigation is required. Nonetheless, the ULSD EIR attributes the full amount of indirect emissions from increased hydrogen production to the ULSD Project because the Refinery's actual hydrogen demand varies from time to time, and it is not possible to determine the precise proportion of hydrogen that will be supplied by the Air Products Carson Hydrogen Plant and other sources. This provides another level of conservatism to the air quality analysis in the ULSD EIR.

Response 1-53

This comment incorrectly asserts that the Draft EIR did not state any basis for selecting the years 2006 through 2008 as the post-project. In Section 3.1 of the Draft and Final EIRs, the following rationale is given for why the years 2006 through 2008 were selected as the post-project period.

> Since the ULSD Project went through start-up and de-bugging procedures in April 2006, the "post-project" period is considered to be May 2006 and thereafter. For the purposes of evaluating air quality impacts from the ULSD Project, the "post-project" period for the ULSD Project is May 2006 through April 2008. This period length was selected in order to compare an equivalent period of time, two years of operation, to the baseline conditions, which were developed using two years (2002 – 2003) of historical data. A two year period allows the data to reflect the various changes in operation such as shut down for maintenance, market demands, etc. Where available data did not precisely match these pre- and post-Project periods, the impact analysis relies on the best available match.

In addition to the above, the baseline and the post project periods were selected to avoid other events and refinery changes that would have obscured the emissions consequences of the project.

In particular (as discussed in Response 1-9), in November 2001 flue gas recirculation was added to Boiler 7, reducing NOx emissions from about 85 ppm to about 46 ppm (a 46 percent reduction, based on RECLAIM data). If a longer pre-project period were used for the baseline, the baseline emissions would appear to be substantially higher because the baseline would have included many months when Boiler 7 was operating without the added controls. SCR was added in December 2008, reducing NOx from 46 ppm to 11 ppm (an 82 percent reduction). If a longer post-project period were used, the post-project period would appear to have substantially lower emissions because it would include many months of operation of Boiler 7 at very low emissions rates due to the SCR unit. The combined effect of using a higher baseline and lower post-project emissions would be to shrink the emissions attributed to the project. The baseline pre-project and post-project periods were chosen to avoid the change in NOx emissions due to these two refinery modifications, which were unrelated to the ULSD Project. To avoid inappropriate influences from these and other independent projects, the South Coast AQMD had to use an approximately two-year period for the pre-project baseline and the post-project period.

The comment then asserts further that the period 2006 through 2008 corresponds to a severe recession during which fuel demand and, thus, hydrogen production emissions would have declined. The comment further asserts that Table 3.1-3 of the 2014 Draft EIR shows that refinery emissions in the year 2007 were among the lowest reported over the period 2000 through 2012, next to lowest for CO emissions, lowest for NOx emissions, lowest for VOC emissions, and third lowest for PM10 emissions. Please note that the data for 2007 is only for six months from July 2007 through December 2007 as the South Coast AQMD changed from requiring annual emissions to be reported on a fiscal reporting year (July through June) to a calendar reporting year (January through December). Therefore, the emissions data for 2007 only includes six months of data, not 12 months as for the other reporting periods. A footnote has been added to Table 3.1-3 in the Final EIR to clarify the data.

According to the U.S. National Bureau of Economic Research (the official arbiter of U.S. recessions) the U.S. recession began in December 2007 and ended in June 2009, and thus extended over 19 months. The simultaneous multiple crises affecting the U.S. financial system in mid-September 2008 caused large falls in markets both in the U.S. and elsewhere. As a result, real gross domestic product (GDP) began contracting in the third quarter of 2008[12].

Based on the above information, the recession officially started in December 2007, which means that refinery emissions, as well as hydrogen production emissions, during 2006 and 2007 were essentially unaffected by the recession. Refinery-wide emissions in 2006, shown in Table 3.1-3 of the 2014 Draft EIR, were in the upper range of emissions over the 14-year period, although as indicated above, the recession began well after the year 2006. Since the market did not begin contracting until December 2007, the refinery emissions in 2007 reflect other factors (e.g., unit turnarounds), not effects of the recession. Therefore, the assertion that post project hydrogen production emissions (and refinery emissions), particularly refinery emissions in the year 2007, are uncharacteristically low because of the recession is not supported by the facts.

The year 2008 is the only year of the post-project period that falls fully within the recession. The data indicate, however, that, although the economy was contracting, the major economic effects

[12] The Great Recession at http://stateofworkingamerica.org/great-recession/, Accessed December 12, 2017.

(market disruptions) of the recession began in the last quarter of 2008. Therefore, the effects of the recession on refinery operations in 2008 were minimal, at least through the first three quarters. If demand for fuel had been reduced because of the recession, the year 2008 should have been the post-project year with the lowest refinery emissions. This was not the case, as shown by the data in Table 3.1-3 of the 2014 Draft EIR, which show refinery-wide emissions in 2008 as being in the middle of the range of refinery emissions over the 14-year period. Also, as shown in Table 3.1-3 of the 2014 Draft EIR, other years with generally low refinery-wide emissions include 2012 and 2013 (although NOx emissions for 2013 are relatively high), years substantially after the end of the recession. For all of the above reasons, the commenter's assertion that the hydrogen production emissions are underestimated because of the effects of the recession during the post-project period is not supported by any facts and is not correct.

Response 1-54

This comment asserts that there is no evidence in the record that peak hydrogen demand from modified Unit 90 occurred during the post-project years 2006 to 2008. As indicated in Subsection 3.3.2.1, the Refinery does not monitor hydrogen use in Unit 90 alone. The Refinery monitors the total hydrogen used in Unit 89 (jet hydrotreater) and Unit 90 (diesel hydrotreater) combined on an annual basis.

The baseline hydrogen demand in Units 89 and 90 was based on monitoring data of hydrogen use in 2002-2003 for the two units combined. The total increase in hydrogen used by Units 89 and 90 combined between the pre-project and the post-project periods was attributed to the Unit 90 for ULSD Project because no modifications were made to Unit 89. The Draft EIR clearly states that the overall use of hydrogen increased over the baseline period by about 511 million standard cubic feet per year (mmscf/year) or about 1.40 mmscf/day (see Appendix B). The analysis included the conservative assumption that all of the increase in hydrogen use was attributed to the ULSD Project (Unit 90 hydrogen demand increase). The assumption is considered to be conservative because any increase in hydrogen demand compared to the baseline, regardless if it is from Unit 89 and/or Unit 90, is attributed to the ULSD Project. However, as comment 1-54 notes, the estimated increase in hydrogen use in the Draft EIR was based on actual average conditions. The Final EIR has been revised to include emission estimates for peak hydrogen use as well as average hydrogen use and detailed emission calculations can be found in Appendix B of the Final EIR. The actual increase in peak day hydrogen demand for Units 89 and 90 combined was calculated as the difference between the pre-project peak day from 2002-2003 (13.12 mmscf on June 26, 2002) and the post-project peak day from 2006-2008 (16.96 mmscf on October 23, 2007), or 3.84 mmscf. This increase of 3.84 mmscf was attributed solely to Unit 90 to ensure the worst-case demand was attributed to the ULSD Project. The average actual emissions as shown in the Draft EIR and the peak hydrogen production emissions are shown in Table 11. The Final EIR has been revised to include the peak hydrogen production emission estimates as well as the average hydrogen production emission estimates.

TABLE 11

Average And Peak Hydrogen Production Emission Increase

	CO	VOC	NOx	SOx	PM10	PM2.5(1)
Emission Factor (lb/mmscf)(2)	1.63	1.63	2.5	0.07	1.95	1.95
Average Actual Emissions (lbs/day)(3)	2.28	2.28	3.50	0.10	2.73	2.73
Peak Actual Emissions (lbs/day)(4)	6.26	6.26	9.60	0.27	7.49	7.49

(1) PM2.5 emissions are assumed to be equivalent to PM10 emissions.

(2) City of Carson, EIR for the Air Products Hydrogen Facility and Specialty Gas Facility (SCH# 97071078), June 15, 1998.

(3) Approach: The average actual hydrogen demand for Units 89 and 90 combined was compared from 2002-2003 and 2006-2008. The increase was attributed to U90 solely to ensure the worst-case demand was attributed to the ULSD Project.

(4) Approach: The actual peak day hydrogen demand for Units 89 and 90 combined was compared from 2002-2003 (13.12 mmscf on June 26, 2002) and 2006-2008 (16.96 mmscf on October 23, 2007). The peak increase from those days of 3.84 mmscf was attributed to U90 solely to ensure the worst-case demand was attributed to the ULSD Project.

This comment also asserts that, not only does the post-project period 2006 to 2008 correspond to a recession when the demand for diesel was depressed, but states that diesel production has been trending up since 2008. With regard to the effects of the recession, see Response 1-53. With regard to future diesel trends, the implication in the comment is that increased diesel demand will result in even higher post-project emission impacts. This assertion ignores the fact that refinery operations fluctuate with market conditions and that total refinery production capacity is limited by physical constraints as well as limitations placed on equipment emissions through South Coast AQMD permit conditions, as explained in the following paragraphs.

The commenter infers that diesel trends have been increasing and cites information from three online articles. The first article cited by the commenter indicates that, as of 2013, national production of diesel is increasing at a faster rate than gasoline. However, the article also indicates that increasing production levels are being met nationally by building additional diesel refining capacity. The purpose of the ULSD Project was to comply with regional, state, and federal regulations to produce diesel that complies with the sulfur content requirements; the project did not add additional diesel refining capacity.

The second article cited in the comment provides a graph and data that appear to show that diesel production has increased since approximately 2001. This trend is confirmed by the third article which states, "Since 2001, distillate yields have followed an upward trend, peaking in December 2008 before falling back to an average of 27.5% in 2010." The three articles cited in the comment refer to national trends and have limited relevance to the ULSD Project, which, as stated above, was undertaken to comply with local, state, and federal diesel sulfur content requirements, not to increase diesel production capacity.

Refinery activities fluctuate over time in response to variations in demand for petroleum products. Table 3.1-3 in the 2014 Draft EIR shows how refinery emissions fluctuate over time based on overall demand for petroleum products. Refineries strive to optimize the volumes or yields of higher value products, such as transportation fuels (i.e., gasoline, diesel, and jet fuel) while producing the maximum quantity of saleable products from each barrel of crude oil refined. Refiners can adjust product yields in response to changing product prices and other market conditions by varying refinery processes and other factors. If market forces drive greater demand for diesel, for example, then a refinery could modify existing operations to increase the production of diesel, but reduce refinery operations producing gasoline or jet fuel. However, refinery operations are limited by existing physical limitations and emission limitations from South Coast AQMD permits.

To process refined products, including diesel, the various process units must operate within their physical design limitations. The operating parameters of the various process units in turn limit products that can be processed by a particular refinery configuration. These physical constraints include a limitation on the amount of diesel that can be recovered from gas oil in the Fluid Catalytic Cracking Unit (FCCU), for example. Other physical constraints to increasing the yield of diesel includes the Hydrocracker Unit (HCU), which cracks or converts mid-distillate and heavy hydrocarbons to lighter gasoline, jet, and diesel range material in the presence of catalyst, heat, and hydrogen. Therefore, to increase diesel production beyond the current capacity at the Phillips 66 Refinery would require new equipment, such as those identified above, or modifications to existing equipment. The components of the ULSD, including new and modified equipment, only allow the Refinery to reduce the sulfur content of diesel, not produce additional diesel.

In additional to physical limitations, operation of any stationary equipment that emits pollutants directly or produces fugitive emissions is regulated by South Coast AQMD permit conditions. Limiting emissions can occur through installing control equipment, which places physical constraints on the operating capacity, or limiting operations. Equipment modifications to increase diesel production would require the operators of the Phillips 66 Refinery to submit applications to modify the Refinery Title V operating permit with the South Coast AQMD to add or modify equipment such as the FCCU, HCU, etc., as discussed above. No such modifications to existing equipment or addition of new equipment to produce additional diesel were included as part of the ULSD Project.

Response 1-55

This comment asserts that increased hydrogen demand for modified Unit 90 should have been based on permit limits, if any or the design throughput in barrels per day. The comment also asserts that the maximum day hydrogen demand is not disclosed in the Draft EIR. As discussed in Response 1-54, the Final EIR has been revised to include emission estimates for peak hydrogen use as well as annual average emissions. The actual increase in peak day hydrogen demand for Units 89 and 90 combined was calculated as the difference between the 2002-2003 peak day (13.12 mmscf on June 26, 2002) and the 2006-2008 peak day (16.96 mmscf on October 23, 2007). The increase calculated from comparing those peak days was assumed to occur for the entire year and attributed solely to Unit 90 to ensure the worst-case demand was attributed to the ULSD Project. Thus, the assumptions overestimate hydrogen use by Unit 90 but also provide an estimate of the peak daily use. No permit limit has been established on the maximum hydrogen use for the modified Unit 90; however, there is an South Coast AQMD permit for the Air Products Hydrogen Plant that establishes enforceable permit limits and the construction and operational impacts associated with that Hydrogen Plant have been subject to environmental review in a Final EIR prepared by the City of Carson, when those limits were approved. The average actual and peak hydrogen production emissions are shown in Appendix B, Table 4 of the Final EIR.

Response 1-56

This comment again asserts that post-project emissions from Unit 90 should be based on permit limits or the physical design of Unit 90. Further, if neither permit limits nor physical design information is available, the comment asserts that daily hydrogen production data over the period 2000 to 2013 should have been used to determine whether hydrogen use during the 2006 – 2008 recession is representative of the peak day. As discussed in Response 1-55, no permit limit has been established on the maximum hydrogen use for the modified Unit 90. However, an enforceable permit limit for hydrogen use is not necessary because the South Coast AQMD permit for the Air Products Hydrogen Plant has established enforceable permit limits and the construction and operational impacts associated with that Hydrogen Plant have been subject to environmental review in a Final EIR prepared by the City of Carson. As discussed in Response 1-54, since the project has been constructed and operating, the average and peak hydrogen use were based on data from actual daily hydrogen use. To identify the effects of the ULSD Project, it was necessary for the South Coast AQMD to compare baseline and post-project periods that were not influenced by other, independent changes at the refinery, which required evaluating other years to ensure that the pre-project emissions were not atypically high while post-project emissions where not atypically low. In particular, in November 2001, flue gas recirculation was added to Boiler 7, which substantially reduced NOx emissions from this piece of steam generating equipment. If a longer pre-project period were used for the baseline, the baseline emissions would appear to be substantially higher because the baseline would have included many months when Boiler 7 was operating without the added controls. Also, a SCR unit was added to Boiler 7 in December 2008, which substantially reduced NOx emissions from this piece of steam generating equipment. If a longer post-project period were to be used, the post-project period would appear to have substantially lower emissions because it would include many months of operation of Boiler 7 at very low emissions rates due to the SCR unit. The combined effect of using a higher baseline and lower post-project emissions would be to shrink the emissions attributed to the project. For these reasons, selecting emissions from before the year 2002 and after the year 2008 would not provide relevant information on the actual effects of the ULSD Project.

The comment also suggests that reviewing other years is necessary to determine whether hydrogen use "during the 2006-2008 recession, when diesel demand likely declined, is representative of the peak post-project day." As indicated above, it is inaccurate to describe all of the post-project years as part of a recession. See Response 1-53 for additional information regarding why the recession had little effect on overall Refinery operations in the post-project period of 2006 to 2008.

Response 1-57

This comment asserts that increased hydrogen demand from the ULSD Project is based on a daily annual average hydrogen demand. As discussed in detail in responses 1-54 and 1-55, the

Final EIR has been revised to include emission estimates for the change in peak day hydrogen use as well as for the change in average day hydrogen use.

Response 1-58

This is a summary comment that summarizes the more detailed comments provided in Comments 1-59 through 1-61. This comment notes that, because increased demand for hydrogen would be supplied entirely by a third party – Air Products – emission factors used to calculate hydrogen production for the ULSD Project are based on emission factors found in the Final EIR for the Air Products Hydrogen Facility and Specialty Gas Facility (SCH#97071078), June 1998. As a result, peak emissions from hydrogen production have already been accounted for in a CEQA analysis and no further CEQA analysis is required. The commenter then asserts that, not only does the Draft EIR not cite pages in the 1998 Final EIR where the Air Products emission factors are found, but emission factors used for the ULSD Project are not found in the 1998 Final EIR.

The emission factors were determined as suggested in the comment. The total emissions attributed to the Air Products project in its Final EIR assumed peak operations of 96 million standard cubic feet per day. For use in calculating emissions associated with hydrogen consumption for the ULSD Project, the peak daily hydrogen plant emissions were divided by the maximum daily hydrogen production of the hydrogen plant to calculate pounds of NOx emissions per unit of hydrogen gas produced, e.g., (156 lbs NOx/day)/96 mmscf hydrogen produced per day = 1.63 lbs NOx/mmscf hydrogen produced. Therefore, sufficient data were provided in the Draft EIR for the commenter to understand the emission calculations. The South Coast AQMD disagrees with the comment that "the DEIR improperly reduced emissions reported in the Hydrogen Plant FEIR by excluding most emissions sources." This is incorrect as explained in Response 1-59, which provides more details on the appropriate emission factors to calculate for the hydrogen plant.

Response 1-59

This comment includes a number of assertions suggesting that the Draft EIR for the ULSD Project underestimated emissions, NOx emissions in particular, because the analysis did not include emissions from all emissions sources necessary to produce hydrogen at the Air Products Hydrogen Plant. Specifically, the comment asserts that hydrogen production produces emissions from various indirect sources including material delivery, truck transport of CO_2, and worker travel. The commenter then states that these emissions sources were not included as part of the analysis of hydrogen production emissions used for the ULSD Project. Instead, the comment asserts, the analysis of hydrogen production emissions in the Draft EIR for the ULSD Project only included emissions from the hydrogen plant and reformer heater.

The comment also asserts that analysis of hydrogen production emissions did not include flaring emissions at the Air Products facility (see page 3-35 of the 2014 Draft EIR) even though the analysis of hydrogen production in the 1998 Final EIR included flare emissions and other indirect emissions sources as part of the emission impacts of that project. (It is assumed that the reference to other indirect emissions sources means material delivery, truck transport of CO2, and worker travel.)

Peak emissions directly from the Air Products Hydrogen Plant and reformer heater, as well as from material delivery, truck transport, worker travel, and flaring have already been disclosed and analyzed in the 1998 Final EIR for the Air Products Hydrogen facility, SCH# 97071078. The ULSD Project will not change in any way the operation of the Air Products Hydrogen Plant as it was described in the 1998 Final EIR. At most, Phillips 66 is a customer that purchases product from a facility/project that underwent its own full CEQA review. As such, under CEQA, Pub. Res. Code Section 21166, and CEQA Guidelines Section 15162, no further CEQA review of the emissions or any other impact of the Air Products Hydrogen Plant is required in conjunction with the review of the ULSD project. Nonetheless, for the reader's convenience, the EIR for the ULSD project describes basic information regarding hydrogen production at the Air Products Hydrogen facility.

As noted in Response 1-45, assigning *all* daily emissions from the Air Products Hydrogen facility and its indirect sources, especially peak daily emissions, to the ULSD Project is inappropriate, obscures, and over estimates the actual contribution of indirect emission impacts from the ULSD Project. The emissions from material delivery, truck transport of carbon dioxide and worker travel associated with operation of the Air Productions Hydrogen Plant project are expected to continue with or without any hydrogen being sold to Phillips 66. The ULSD Project would use one to four percent of the total hydrogen production from the Air Products Hydrogen Plant. If Phillips 66 did not purchase this small fraction of the hydrogen plant's output, that amount of hydrogen would either be sold to another customer, or Air Products would adjust its output. But either way, there is no evidence that would result in any change in employment, worker traffic, or deliveries supporting operation of the Air Products Hydrogen Plant. With respect to fugitive VOC emissions from valves, pumps and flanges, the Hydrogen Plant included fugitive components. However, components in hydrogen or natural gas service do not contain VOC emissions so no fugitive VOC emissions are associated with the Hydrogen Plant.

Similarly, the commenter assumes – with no supporting evidence – that the identity of the hydrogen purchaser (i.e., Phillips 66 as opposed to any other customer) or a one to four percent difference in hydrogen production affects the frequency or extent of flaring. Obviously, if Phillips 66 did not purchase hydrogen and that amount was purchased by another customer, hydrogen plant operations and emissions would not change. But even if there were no alternative customer for the small amount hydrogen required by the ULSD Project, emissions from the Air Products Hydrogen Plant flare would be unaffected. Emissions from a flare come from the constant operation of the pilot flame (needed to maintain a state of readiness), and the periodic combustion of excess gases arising from unforeseen circumstances. Pilot emissions are constant and unrelated to the rate of production at the hydrogen plant, because safety concerns require that the pilot remain lit at all times; therefore, the flare pilot emissions are unchanged by an increase or decrease in hydrogen production. Likewise, the need to combust excess gases in the flare is unrelated to and unaffected by variations in production of one to four percent. The commenter provides no evidence that an increase in flaring is tied to one to four percent of the hydrogen output of the Air Products Hydrogen Plant, and there is nothing in the 1998 Final EIR for the Air Products Hydrogen Facility supporting commenter's speculative assumption. Phillips

66 does not own or control the Air Products Hydrogen Plant and has no input into the operation of the Plant. Flaring results from operator actions and independent events that are not tied to the manufacture or purchase of a small amount of the plant's total hydrogen production capacity. For example, flaring can result from equipment malfunction, operator error, electricity outage and other types of independent and/or external events. The comment provides no evidence that the purchase of one to four percent of the hydrogen output by Phillips 66 affects whether these independent and external events occur or the frequency or extent of flaring. The potential for flaring from the Air Product Hydrogen Plant does not change or increase as a result of the production of one to four percent of hydrogen production. As discussed further in Response 1-58, peak emissions from hydrogen production have already been accounted for in a separate CEQA analysis and no further CEQA analysis is required for the Hydrogen Plant.

The ULSD Draft EIR calculated and disclosed a 1.5 to four percent share of the emissions from the Air Products Hydrogen Plant's boiler/reformer heater emissions, operating at peak production. The incremental increase in hydrogen use at Phillips 66 (an estimated average increase of 1.4 mmscf/day or an estimated increase in peak use of 3.8 mmscf/day as compared to the total potential hydrogen generation at the Air Products Hydrogen Plant of 96 mmscf/day (about 1.5 to four percent of the Air Product Plant's capacity percent during peak use) would not impact indirect emissions associated with ongoing operation of the Air Products Hydrogen Plant, including material delivery (truck trips), the transport of carbon dioxide (a separate product generated by the Specialty Gas Plant), or worker and other mobile source travel (no increase in workers at the hydrogen plant was required to sell hydrogen to Phillips 66). Therefore, the emissions provided in Table 1 of Comment 1-59 on lines 2 and 3 are incorrect because they inappropriately include emissions from ongoing operation of the Air Products Hydrogen Plant that would not change regardless whether Phillips 66 purchases hydrogen for the ULSD project.

Further, the comment references unmitigated emissions from the Air Productions Hydrogen Plant Final EIR. As shown in Table 5-17 of the Air Products Final EIR and summarized in Table 12 below, mitigated operational emissions from the Hydrogen Plant are expected to be much less than reported by the commenter. The Air Products Hydrogen Plant Final EIR included mitigation measures that required that all stationary source emissions be offset and that hydrogen be vented as opposed to flared, thus eliminating the worst-case flaring event. As shown in Table 12, the mitigated NOx emissions for the operation of the Air Products Hydrogen Plant (including flaring emissions) were estimated to be 30 lbs/day in the Final EIR as opposed to the NOx emissions attributed in Comment 1-59, Table 1 of 240 lbs/day to the small (one to four percent) fraction of the production that would be used by the ULSD Project.

TABLE 12

Mitigated Operation Emissions from the Entire Air Products Hydrogen Plant and Operations

	Units	CO	VOC	NOx	SOx	PM10	PM2.5
Mitigated Operational Emission Estimates	lb/day	80	-6	30	5	-21	-21
Emission Factor	lb/mmscf	0.83	-0.6	0.31	0.05	-0.22	-0.22

Source: Final EIR for the Air Products Hydrogen Facility and Specialty Gas Facility, June 1998, Table 5-17.

Comment 1-59 also includes a table (Table 1) that compares the hydrogen production emission factors used in the Draft EIR for the ULSD Project to hydrogen production emission factors calculated by the commenter to try to demonstrate that the emission factors used by the South Coast AQMD underestimated emissions from the project. The magnitude of the misrepresentation of the hydrogen plant emissions by the commenter is shown in Table 13. The Air Products Hydrogen Plant reports its total emissions from all stationary sources (including flares) to the South Coast AQMD on an annual basis. Table 13 shows the total emissions from the Air Products Hydrogen Plant reported on an annual basis in tons per year, the average daily emissions from the Plant, and provides the total actual emissions reported to the South Coast AQMD as part of its annual emission fee program.

TABLE 13

Reported Emissions for the Entire Air Products Hydrogen Plant(1)

Year	CO (tpy)(2)	CO (lbs/day)(3)	NOx (tpy)	NOx (lbs/day)	ROG (tpy)	ROG (lbs/day)	SOx (tpy)	SOx (lbs/yr)	TSP (tpy)	TSP (lbs/day)
Reported Emissions for the Entire Air Products Hydrogen Plant (2002-2003)										
2002	0.754	4.132	6.433	35.249	2.698	14.784	0.230	1.260	1.450	7.945
2003	0.758	4.153	6.768	37.085	1.797	9.847	0.225	1.233	0.751	4.115
Reported Emissions for the Entire Air Products Hydrogen Plant (2006-2008)										
2006	2.391	13.101	8.213	45.003	7.896	43.266	0.177	0.970	2.790	15.288
2007(4)	1.320	14.505	5.369	59.000	3.691	40.560	0.102	1.121	1.338	14.703
2008	11.304	61.940	13.592	74.477	20.266	111.047	0.223	1.222	5.356	29.348
Emissions estimated in Comment 1-59, Table 1, Line 5(5)	--	156	--	240	--	156	--	7	--	187

(1) Annual emissions are reported to the South Coast AQMD and available from the South Coast AQMD FINDS database. Pounds per day emissions were calculated by dividing the annual reported emissions by 365 operating days.
(2) tpy = tons per year
(3) lbs/day = pounds per day
(4) The data for 2007 are based on six months' worth of data because the South Coast AQMD revised the emission fee period from a fiscal year to a calendar year.
(5) Annual emissions were not included in Comment 1-59.

As shown in Table 13 the actual entire emissions of NOx for the operation of the Air Products Hydrogen Plant (including flaring emissions) ranged from about 35.3 to 75.5 lbs/day as opposed to the NOx emissions attributed in Comment 1-59, Table 1 of 240 lbs/day to the small (one to four percent) fraction of the production that would be used by the ULSD Project. Therefore, the emissions estimated by the commenter in Comment 1-59 are unfounded and vastly overestimate the actual emissions from the ULSD project.

The ULSD Project would use an average of about 511 mmscf/year or 1.4 mmscf/day. Therefore, the emissions from the Hydrogen Plant that may be attributable to the ULSD Project ranges from less than one pound per day (SOx and TSP) to 3 lbs/day for NOx. In fact, the emissions estimated in the ULSD Draft EIR of about 3.5 lbs/day for NOx are closer to the actual emissions that have been reported from the operation of the Air Products Hydrogen Plant as a whole, while supplying the ULSD Project with hydrogen accounts for one to four percent of the total hydrogen production. Therefore, the NOx emissions reported for the ULSD Project provide a conservative estimate of the ULSD Project impacts related to hydrogen production. Therefore, using actual data reported by the Air Products Hydrogen Plant to the South Coast AQMD, the total NOx emissions from the operation of the plant are well below the ULSD NOx emissions estimated in the Draft EIR. Therefore, the assertion that the NOx emission factor used to estimate emissions from the Hydrogen Plant underestimated NOx emissions is disproven by the South Coast AQMD annual emissions data for the Air Products Hydrogen Plant.

Further, the peak emissions from the Air Products Hydrogen Plant have already been accounted for in the 1998 Final EIR. Increased hydrogen production emissions resulting from the ULSD Project are considered to be indirect emission increases, so only the incremental increase in hydrogen production emissions compared to the baseline should be attributed to the ULSD Project, not the peak emissions from the entire Air Products Hydrogen Plant. To attribute all emissions from the Air Products Hydrogen Plant to the ULSD Project would artificially and incorrectly inflate emissions from the ULSD Project. Consequently, the assertion that hydrogen production emissions estimated for the ULSD Project are underestimated is misleading and without merit. Also see Response 1-60 regarding the emission factors for flaring.

The comment asserts that review of the Title V permit for the Air Products Hydrogen Plant reveals that the permit does not contain any limits that would prohibit or restrict flaring. Footnotes 12 and 13 show flare emissions from the 1998 Final EIR. However, the flare emissions in footnotes 12 and 13 are no longer relevant for the following reasons. This comment appears to ignore the fact that flares are stringently regulated by South Coast AQMD Rule 1118, which strictly regulates flare emissions from all flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants. Rule 1118 was first adopted February 13, 1998, but did not impose emission limits until January 1, 2006. Effective January 1, 2007, Rule 1118 required all flares to operate in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs. Further, Rule 1118 required flare gas recovery and treatment systems to be installed by January 1, 2009 and facilities are required to report their flaring emissions to the South Coast AQMD on a quarterly basis since 2007.

Analysis of the Air Products Hydrogen Plant in the 1998 Final EIR was conducted before the adoption of Rule 1118 and well before its requirements became effective. Consequently, it was reasonable for the analysis in the 1998 Final EIR to include flare emissions. Since the facility has been subject to Rule 1118 after publication of the 1998 Final EIR, requirements to minimize flaring and install the required flare gas recovery and treatment system would serve to minimize flare emissions by reducing or avoiding flaring events. Finally, even though Air Product's Title V permit may not include limitations on flare emissions, the facility is still subject to Rule 1118, which does limit flare emissions. Consequently, the assertion that the analysis of hydrogen production emissions for the ULSD Project should include flaring emissions ignores the requirements of Rule 1118 and the fact that peak flare emissions have already been accounted for in the 1998 Final EIR and, therefore, is without merit. Also, see Response 1-60 for further information on flare emission factors and their related emissions.

Response 1-60

This comment states that emissions reported in the 1998 Air Products Hydrogen Plant Final EIR were based on an emission factor that U.S. EPA has since determined underestimates flaring emissions. Footnote 14 cites the 1998 Final EIR and footnote 15 cites the U.S. EPA reference for flare emission factors at petroleum refineries. Based on information provided in footnote 15, the comment implies that hydrogen production flaring emissions at the Air Products Hydrogen Plant would have been even greater than those reported in the 1998 Final EIR if newer emission factors had been used. As a result, the comment then asserts that indirect hydrogen production emissions from the ULSD Project would also be higher, resulting in greater emission impacts.

Footnote 15 in the comment cited to a draft EPA document, and EPA intentionally omitted the revision to the NOx emission factor when it finalized the document. The update to the Emissions Estimation Protocol for Petroleum Refineries was finalized in April 2015 (Version 3)[13]. The NOx emission factor for flares in Table 6-2 of the U.S. EPA Protocol document is 0.068 lb NOx/10^6 mmBtu. Therefore, the emission factor used in Comment 1-60 (2.9 lb/mmBtu) is not correct and was not based on the approved Final Emissions Estimation Protocol for Petroleum Refineries. Further, the South Coast AQMD currently recommends using the same emission factor (0.068 lb NOx/10^6 mmBtu) as part of South Coast AQMD Rule 1118 requirements for emission calculations from flares.[14]

The EPA emission factor referenced in Comment 1-60 is based on an August 2014 Draft Emissions Protocol for Petroleum Refineries; which was finalized in April 2015. When the document was finalized, the U.S. EPA determined that the NOx emission factor for flares did not need to be updated and the emission factor referenced in Comment 1-60 was abandoned by the U.S. EPA. The emission factor cited in Comment 1-60 appears to be based largely on a handful of refineries in and around Houston. The EPA study mentions a Houston Differential Adsorption Lidar (DIAL) study in 2008 and a Texas Commission on Environmental Quality (TCEQ) study in 2010.

[13] https://www.epa.gov/air-emissions-factors-and-quantification/emissions-estimation-protocol-petroleum-refineries
[14] South Coast AQMD Rule 1118 – Control of Emissions from Refinery Flares, Attachment B, Guidelines for Calculating Flare Emissions, amended July 7, 2017. http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1118.pdf?sfvrsn=4

The U.S. EPA backed away from revising the NOx emission factor for flares when the Emissions Protocol for Petroleum Refineries was finalized in April 2015. The Houston DIAL study was focused on VOCs, and the TCEQ 2010 study took some NOx measurements but did not properly calibrate the equipment. With respect to the latter, EPA said:

> *The passive FTIR spectrometer for this study was not calibrated for NOx and therefore these data cannot be used, as the quality of the data has a high degree of uncertainty. The 2010 TCEQ flare study also contained extractive data measurements for NOx. However, the report specifies that "NOx was also measured during the flare tests, but it is not included because NOx was measured using a commercial chemiluminescence analyzer. This instrument did not meet the data quality objectives over all the ranges of DRE observed." (See p. 124 of Allen and Torres, 2011). The report provides no further details on which data quality objectives the instrument failed to meet and whether all data was affected. As such, there is a high degree of uncertainty with all of the NOx extractive data obtained from the flare study. Because the extractive NOx measurements did not meet the data quality objectives, the resulting data are not appropriate for use in developing revised NOx emissions factors for flares.*[15]

Similarly, there was no proper calibration of NOx measurement equipment in a third study, referred to as the Marathon Petroleum Flare Tests, a fourth study, called the Flint Hills Port Arthur Flare Test, or yet another test of an Ineos flare. EPA was unable to even obtain the raw NOx data for certain IFC studies, but noted that the range of NOx values reported in these studies fell within the range of the existing AP-42 NOx emission factor for flares.

Overall, EPA concluded:

> *Although some of the studies summarized above also reported NOx emissions data, the instruments were not calibrated for measuring NOx and/or the measurement system failed data quality objectives. For this reason, the NOx data are not appropriate for use in revising the NOx emissions factor for flares. Nonetheless, the extractive NOx data that are available, while not fully validated, is in the range of the existing AP-42 factor. Therefore, we also conclude that it is not necessary at this time to revise the existing AP-42 NOx emissions factor for industrial flares.*

For additional information regarding flare emissions from the Air Products Hydrogen Plant, refer to Response 1-59. Based on the above, the emission factor of 2.9 lbs/mmbtu for flares that was used in Comment 1-60 was not adopted by the U.S. EPA as high quality data were not available. Consequently, the assertion that hydrogen production emissions estimated for the ULSD Project are underestimated is misleading and without merit.

[15]EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Systems, April 2015. https://www3.epa.gov/ttn/chief/consentdecree/final_report_review.pdf

The magnitude of the misrepresentation of the flare emissions estimated by the commenter from the Air Products Hydrogen Plant is shown in Table 14.

TABLE 14

Flare Emissions from Air Products Hydrogen Plant(1)

Timeframe(2)	CO (lbs)	VOC (lbs)	NOx (lbs)	SO_2 (lbs)	PM10(lbs)
2007					
Quarter 1	3,602	617	1,121	3	666
Quarter 2	208	36	136	1	41
Quarter 3	367	73	1,363	9	79
Quarter 4	1,829	328	2,352	497	354
2007 Annual Emissions	6,006	1,054	4,972	510	1,140
2008					
Quarter 1	3,492	611	2,654	14	657
Quarter 2	2,195	391	2,427	14	422
Quarter 3	604	121	2,244	14	129
Quarter 4	449	90	1,665	11	96
2008 Annual Emissions	6,740	1,213	8,990	53	1,304
2009					
Quarter 1	526	105	1,953	13	113
Quarter 2	517	103	1,921	12	111
Quarter 3	1,534	278	2,243	13	297
Quarter 4	7,357	1,266	2,891	10	1,360
2015 Annual Emissions	9,934	1,752	9,008	48	1,881
2010					
Quarter 1	470	91	1,348	9	99
Quarter 2	476	95	1,764	11	102
Quarter 3	4,821	848	4,047	21	941
Quarter 4	916	167	1,423	8	179
2015 Annual Emissions	6,683	1,201	8,582	49	1,321

(1) Flare emissions are reported to the South Coast AQMD on a quarterly basis under the requirements of Rule 1118 and emissions are reported on the South Coast AQMD's webpage: http://www.aqmd.gov/home/regulations/compliance/r1118/flare-operator-information/air-products-carson-hydrogen-facility.

(2) Quarter 1 = January 1 through March 31; Quarter 2 = April 1 through June 30; Quarter 3 = July 1 through September 30; Quarter 4 = October 1 through December 31.

Table 14 shows the quarterly emissions from the Air Products Hydrogen Plant reported to the South Coast AQMD under South Coast AQMD Rule 1118. South Coast AQMD Rule 1118 was established to reduce emissions from flares and Rule 1118 prohibits the flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds, and essential operational needs and requires the minimization of such flaring events. Rule 1118 has required operators of flares: (1) to control emissions from flares by installing flare gas recovery systems and gas treating systems (or expanding the capacity of existing systems); (2) establish performance standards for flares; (3) impose fees for exceedances of the standards; (4) require a Flare Minimization Plan when flare emissions are exceeded; (5) conduct a Specific Cause Analysis for unplanned flaring events when thresholds are exceeded and implement applicable corrective actions; and (5) establish monitoring and recordkeeping requirements (among others).

The Air Products Hydrogen Plant's total NOx emissions from flaring have ranged from 136 to 4,047 pounds ***per quarter***, which is orders of magnitude less than the 115,800 pounds ***per day*** that comment 1-60 alleges could occur from the ULSD Project alone. Actual data reported by the Air Products Hydrogen Plant demonstrates that the total NOx emissions from flare operations are well below the NOx emissions estimated in the 1998 Final EIR (1,141 pounds per day) and only a tiny fraction of the 115,800 lbs/day alleged in Comment 1-60. As discussed above, the use of a draft EPA document soliciting comment on a flaring emission factor for NOx of 2.9 lbs/mmbtu is incorrect; EPA excluded this higher NOx emission factor from its final guidance and instead used an emissions factor of 0.068 lbs/mmbtu, for unregulated flares. Therefore, the assertion that the NOx emission factor used to estimate emissions from the flare at the Hydrogen Plant underestimated NOx emissions is without merit.

The emission factor used in Comment 1-60 is based on calculations used in Footnote 14 and was calculated in error as the flaring event for the Hydrogen Plant was based on 720 minutes or 12 hours and not 24 hours. The correct calculation for the emission factor is: 1,140.5 lb/day/[1.32 x 109 Btu/hr)(12 hr/day)(mmBtu/106 btu)] = 0.072 lb/mmbtu. Therefore, the emission factor used in the 1998 Final EIR was higher than the current U.S. EPA emission factor for unregulated flares. Also, note that the flare at the hydrogen plant is regulated by South Coast AQMD Rule 1118. As shown in Table 14, the NOx emissions from the flare are much less than the 1,141 lbs/day calculated in the 1998 Final EIR.

Finally, increased hydrogen production emissions resulting from the ULSD Project are considered to be indirect emission increases, so only the incremental increase in hydrogen production emissions compared to the baseline should be attributed to the ULSD Project, not the peak emissions (e.g., flare emissions) from the entire Air Products Hydrogen Plant. To attribute all emissions from the Air Products Hydrogen Plant to the ULSD Project artificially and incorrectly inflates emissions from the ULSD Project. Phillips 66 does not control the operations of the Air Products hydrogen plant. Operational activities at the Air Products Hydrogen Plant that can cause flaring would be expected to occur with or without the ULSD Project. Therefore, to attribute all flaring emissions from the Air Products Hydrogen Plant to the ULSD Project is without merit.

Response 1-61

This comment provides information from the Draft EIR (page 3-35) describing the analysis of emission impacts from increased hydrogen demand for Unit 90. The comment states that combining the hydrogen demand from Unit 90, as modified, with Unit 89, which is not modified as part of the ULSD Project, does not ensure a worst-case analysis because a decline in hydrogen demand from Unit 89 could conceal an increase in hydrogen demand from Unit 90. The comment then recommends that a different metric be used to compare the relative changes in the operations of the two units, such as feed throughput, steam use, or electricity use. This comment is similar to comment 1-54. As described in Response 1-54, the emission estimates associated with the peak hydrogen production have been revised (see Table 11) and are included in the Final EIR. As discussed in Response 1-54 and the EIR Subsection 3.3.2.1, the Refinery does not monitor hydrogen use in Unit 90 alone. As described below, additional data on hydrogen use has been provided when Unit 89 is down and only Unit 90 is operating, thus capturing the concern of the commentator to focus only on Unit 90 operation.

In addition to the analysis in the Draft EIR and the additional analysis described in Response 1-54, the hydrogen demand was also evaluated for Unit 90 when Unit 89 was down and not operating (therefore, hydrogen was only being used in Unit 90) during the baseline and post-project periods. The peak pre-project hydrogen consumption in Unit 90 when Unit 89 was not operating was 12.1 mmscfd. The peak post-project hydrogen consumption in Unit 90 when Unit 89 was not operating was 15.4 mmscfd. Therefore, the measured increase in hydrogen consumption from the actual operation of Unit 90 following implementation of the ULSD Project was 3.3 mmscfd (about 1,204.5 mmscf/year).

As discussed in Response 1-54, the Final EIR has been revised to include emission estimates for peak hydrogen use as well as average hydrogen use. The actual peak day increase in hydrogen demand for Units 89 and 90 combined was determined by comparing the actual peak day from 2002-2003 (13.12 mmscf on June 26, 2002) to the actual peak day from 2006-2008 (16.96 mmscf on October 23, 2007). The peak increase from those days of 3.84 mmscf was attributed to U90 solely to ensure the worst-case demand was attributed to the ULSD Project. The average actual daily emissions increase as shown in the Draft EIR and the peak actual daily emissions increase based on the predicted hydrogen use are shown in Table 11. The Final EIR has been revised to include the peak hydrogen production emission estimates of 3.84 mmscf/day. Since this is a worst-case estimate and higher than the increase in hydrogen consumption in Unit 90 when Unit 89 was not operating, the hydrogen production estimates in the Final EIR will be based on the worst-case estimate of 3.84 mmscf/day (1,401 mmscf/yr).

Footnote 16 provides two references that predict diesel fuel production will increase in the long-term (*U.S. Diesel Fuel Demand to Peak in 2015 While World Demand Will Grow Through 2030*) and in the short-term (*Short-term Energy and Winter Fuels Outlook*). As noted in Response 1-54, the ULSD Project was undertaken to comply with local, state, and, federal diesel sulfur content requirements, not increase diesel production capacity. For additional information on why the ULSD Project does not increase diesel production capacity, refer Response 1-54.

Response 1-62

This comment asserts that the emissions attributed to replacement Heater B-401 are anomalous because, although VOC, PM10, and PM2.5 emissions are approximately 20 percent higher than the same emissions from Heater B-201 (due to a higher firing rate), CO emissions from replacement Heater B-401 are substantially lower than CO emissions from Heater B-201. The comment acknowledges that it is reasonable that NOx emissions would be lower for replacement Heater B-401, because Heater B-201 controlled NOx emissions using low NOx burners, while NOx emissions from replacement Heater B-401 are controlled by SCR control technology.

However, the comment asserts that there is no reason for the apparent decline in CO emissions. The comment provides a comparison of emissions from Heaters B-201 and B-401 (Table 2 in the comment, taken from Table 3.3-7 in the 2014 Draft EIR).

Comment 1-62 erroneously references Table 3.3-7 of the 2014 Draft EIR and should have referenced the emission calculations in Appendix B (page B-3). In general, some of the increases in emissions shown for the new Heater B-401 simply reflect the calculation methodology, in which the baseline emissions reflect actual operations, but the post-project operations are based on the maximum potential to emit. Here, the baseline for existing Heater B-201 was based on actual operational emissions. The refinery generally operates all equipment below the permitted levels to assure compliance with permit conditions, and that was the case with Heater B-201. Also note that the South Coast AQMD permit to operate for Heater B-201 had a permit limit of 400 ppmv for CO emissions (see Attachment 2 to these responses to comments). In contrast, the emissions estimate for the new Heater B-401 were based on the maximum potential to emit. Even though Phillips 66 will likely continue its practice of operating below the permitted maximum, the maximum allowable operations were assumed to occur post-project, thus creating the appearance that emissions for some pollutants could increase. For other pollutants, however, the requirements of the South Coast AQMD's permitting rules ensure that emissions decline through the use of Best Available Control Technology (or corresponding emissions standards) when installing new equipment. The BACT requirements mandated that SCR be included to reduce NOx emissions. In the same way, the decline in CO emissions is because the BACT requirements (South Coast AQMD Rule 1301(a)(1) BACT, 5-10-1996) for new heaters were imposed on the replacement Heater B-401 and they are more stringent than the requirements for Heater B-201. Therefore, CO emissions for Heater B-401 are limited to a maximum of 10 ppmv by the South Coast AQMD Title V operating permit for Heater B-401 (see Attachment 3 to these Responses to Comments) or 0.25 lbs/hour (as compared to the permit limit of 400 ppmv CO for Heater B-201). The detailed emission calculation is provided below and in Appendix B of the Final EIR.

Emissions = CONC x O x SV x Fd x FF

Where:

Emissions	= pounds per hour (0.25)
CONC	= CO concentration (10 ppmv)
O	= Correction for 3% oxygen levels (20.9%/(20.9% - 3%)
SV	= Specific molar volume (28.01 lb/lb-mol/385.3 dscf/lb-mol)
Fd	= Dry Fuel Factor for natural gas (8710 dscf/mmBtu)
FF	= Fuel Flow Rate (34 mmBtu/hr)

The results of the above calculation show that the CO emission rate for Heater B-401 is based on the CO emission limitation of 10 ppmv in the South Coast AQMD operating permit which would result in emissions of 0.25 lbs/hour or 6.04 lbs/day at peak operations (34 mmBtu/hour) for Heater B-401. Further, the firing rate of 34 mmBtu/hr is also included and enforced on the Phillips Title V Operating permit (Condition C1.26).

Although replacement Heater B-401 is characterized as a functionally identical replacement for Heater B-201, this simply means they perform the same function, it does not mean that they have to generate identical emissions. BACT applied to Heater B-401, e.g., 10 ppmv CO for Heater B-401 as compared to 400 ppmv for Heater B-201, further limited CO emissions from the heater. The decline in CO emissions is directly related to the requirement that BACT be installed on all new equipment and BACT for CO for Heater B-401 was determined to be 10 ppmv. Calculations for other pollutants are discussion in Response 1-63 below. No controls were imposed on the heater to reflect a reduction in VOC or PM emissions.

Response 1-63

This comment identifies emission factors from 2014 Draft EIR, Appendix B, page B-3 used to calculate emissions from replacement Heater B-401. The comment then states that the Draft EIR does not show the calculations to determine emissions from replacement Heater B-401.

The project-specific information needed to complete the emissions calculations was provided in the Draft EIR (see Appendix B which included firing rate and CO concentrations) and the calculations were reproducible with the appropriate engineering calculations. Emissions of CO, NOx, and SOx were limited by concentration specific South Coast AQMD permit limits. Emissions of VOC, PM10 and PM2.5 were limited by limiting the maximum allowable firing rate of Heater B-401 in the South Coast AQMD permit. The calculations for the individual emissions are further discussed below.

1. **CO Emissions**

CO emissions for Heater B-401 are limited to a maximum of 10 ppmv by the South Coast AQMD Title V operating permit for Heater B-401 (see Attachment 3 to the Responses to Comments) or 0.25 lbs/hour. In addition, the firing rate of Heater B-401 is limited to 34 mm Btu/hr. The detailed CO emissions calculation is provided below and has been added to Appendix B of the Final EIR. These emissions reflect the maximum allowable CO emissions.

Emissions = CONC x O x SV x Fd x FF

Where:

Emissions	= pounds per hour (0.25)
CONC	= CO concentration (10 ppmv)
O	= Correction for 3% oxygen levels (20.9%/(20.9% - 3%)
SV	= Specific molar volume (28.01 lb/lb-mol/385.3 dscf/lb-mol)
Fd	= Dry Fuel Factor for natural gas (8710 dscf/mmBtu)
FF	= Fuel Flow Rate (34 mmBtu/hr)

Therefore, the CO emissions reported in the EIR for Heater B-401 (see Table 3.3-7 and Appendix B, page B-3) were correctly reported as a maximum of 0.25 lbs/hour or 6.04 lbs/day.

2. NOx Emissions

NOx emissions for Heater B-401 are limited to a maximum of 5 ppmv by the South Coast AQMD Title V operating permit for Heater B-401 (see Attachment 3 to the Responses to Comments) or 0.21 lbs/hour. In addition, the firing rate of Heater B-401 is limited to 34 mm Btu/hr. The detailed NOx emissions calculation is provided below and has been added to Appendix B of the Final EIR. These emissions reflect the maximum allowable NOx emissions.

Emissions = CONC x O x SV x Fd x FF

Where:

Emissions	= pounds per hour (0.21)
CONC	= NOx concentration (5 ppmv)
O	= Correction for 3% oxygen levels (20.9%/(20.9% - 3%)
SV	= Specific molar volume as NO_2 (46.01 lb/lb-mol/385.3 dscf/lb-mol)
Fd	= Dry Fuel Factor for natural gas (8710 dscf/mmBtu)
FF	= Fuel Flow Rate (34 mmBtu/hr)

Therefore, the NOx emissions reported in the EIR for Heater B-401 (see Table 3.3-7 and Appendix B, page B-3) were correctly reported as a maximum of 0.21 lbs/hour or 4.96 lbs/day.

3. SOx Emissions

SOx emissions for Heater B-401 are limited by limiting the concentration of sulfur in the fuel gas to 40 ppm by the South Coast AQMD Title V operating permit for Heater B-401 (see Attachment 3 to the Responses to Comments). In addition, the firing rate of Heater B-401 is limited to 34 mm Btu/hr. The detailed SOx emissions calculation is provided below and has been added to Appendix B of the Final EIR. These emissions reflect the maximum allowable SOx emissions.

SOx Emission Factor = CONC/HHV/SV x MW

Where:

SOx EF	= 0.0051 lbs/mmBtu
CONC	= Sulfur concentration (40 ppm)
HHV	= High heat value (1316 Btu/scf)
SV	= Specific molar volume as SO_2 (379 dscf/lb-mol)
MW	= Molecular weight (64.07 lb/lb-mole)

SOx Emissions = EF x Heater Duty

Where:

SOx Emiss.	= 0.175 lbs/hour or 4.19 lbs/day
EF	= 0.0051 lbs/mmBtu
Heater Duty	= 34 mmBtu/hr

Therefore, the SOx emissions reported in the EIR for Heater B-401 (see Table 3.3-7 and Appendix B, page B-3) were correctly reported as a maximum of 0.175 lbs/hour or 4.19 lbs/day.

4. VOC, PM10 and PM2.5

VOC, PM10 and PM2.5 emissions for Heater B-401 are calculated using South Coast AQMD standard emission factors and the maximum permitted heater duty. The detailed VOC, PM10 and PM2.5 emissions calculation is provided below and has been added to Appendix B of the Final EIR. These emissions reflect the maximum emissions and are limited by limiting the maximum duty of the Heater B-401 (34 mmBtu/hr).

Emissions = EF x 24 hrs/HH x FF

Where:

Emissions	= pounds per day
EF	= Emission Factor (lb/mmscf) (7 for VOC, and 7.5 for PM10 and PM2.5)
24	= Operating Hours per Day
HH	= High heating value (1050 mmscf/Btu)
FF	= Fuel Flow Rate (34 mmBtu/hr)

Therefore, the VOC, PM10 and PM2.5 emissions reported in the EIR for Heater B-401 (see Table 3.3-7 and Appendix B, page B-3) were correctly reported as a maximum of 5.4, 4.9 and 4.9 lbs/day, respectively. Please note that the overall project emissions include both the increase in emissions associated with new Heater B-401, as well as the emission decreases associated with the removal of Heater B-201.

Response 1-64

This comment states that review of the most recent Title V permit for the Phillips 66 Wilmington Refinery dated August 15, 2014, has not been updated to include replacement Heater B-401, but still shows Heater B-201 as the only Unit 90 charge heater. The comment states further that permit limits cannot be verified without an updated Title V permit and that exemptions could result in higher daily emissions than calculated in the EIR.

Please note that Section D (Permit to Operate) of the August 31, 2017 Title V permit for the Phillips 66 Wilmington Plant has removed Heater B-201 from the permit and includes Heater B-401. Previously, Heater B-401 and associated conditions and emissions limits were included in Section H (Permit to Construct) of the Title V permit since 2005. Phillips 66 requested inactivation of Heater B-201 in August of 2009 and a Title V permit without Heater B-201 was issued in November 2009. The applicable portions of the 2017 Title V permit for Heater B-401 are provided in Attachment 3. Please note that the Title V permit limits the concentrations of CO

(10 ppmv), NOx (5 ppmv), and SOx (sulfur limited to 40 ppm in the fuel gas) from Heater B-401 and limits the maximum firing rate of the heater. Emissions of VOC, PM10 and PM2.5 are limited in the South Coast AQMD Title V permit by limiting the maximum firing rate of Heater B-401 to 34 mmBtu/hr (see Section H page 25, of the August 31, 2017 Title V permit, Condition C1.26, the applicable portions of which are included in Attachment 3).

Comment 1-64 states that exceptions to permit limits during startup and shutdowns may result in NOx emissions that could be substantially higher than reported in the EIR. This comment summarizes a comment made in more detail in comment 1-67, asserting that permits often contain exceptions to permit limits for SCRs, for example, such as during unit startups and shutdowns. While the South Coast AQMD Title V permit contains such exceptions, the peak NOx emissions in the analysis occur during peak operations and not during startup/shutdown conditions. Refer to Response 1-67, which addresses this assertion.

<u>Response 1-65</u>

This comment states that permit limits are typically accompanied by an averaging time, such as daily, hourly, or annual average. Averaging times for new or modified equipment that are part of the ULSD Project must be reviewed to determine if they represent maximum daily emissions.

Averaging times in the South Coast AQMD permit for criteria pollutants from Heater B-401 are summarized in Table 15.

TABLE 15

Pollutant Averaging Periods in South Coast AQMD Permit for Heater B-401

Pollutant	Permit Limit	Averaging Period Identified in South Coast AQMD Permit	South Coast AQMD Permit Condition
CO	10 ppm	60 minutes	A195.5
NOx	5 ppm	60 minutes	A195.4
SOx	40 ppm(1)	4 hour average	B61.6
VOC, PM	(2)	60 minutes	C1.26

(1) 40 ppm total sulfur limit in fuel gas
(2) VOC, PM10 and PM2.5 emissions are limited by limiting the heater duty to 34 mmBtu/hr.

The analysis of impacts in the EIR for combustion equipment that comprises the ULSD Project relies on peak hourly emissions that can be achieved by the equipment, multiplied by 24 hours to determine the peak emissions per day and, therefore, would constitute maximum daily emissions and not annual average or monthly average emissions as implied in Comment 1-65.

<u>Response 1-66</u>

This comment asserts that if permit limits do not require adequate testing, permit limits used in the Draft EIR cannot be supported and cannot be used to establish maximum post-project emissions. The comment further asserts that the permit for Heater B-201 did not require testing for NOx, PM10, or PM2.5 and only required periodic stack tests for CO. Finally, the comment asserts that if compliance testing for Heater B-401 is the same as for Heater B-201 without adding additional monitoring (e.g., continuous emissions monitoring), the analysis of post project emissions is unsupported. As discussed below, the permit for Heater B-401 (see Attachment 3) contains source testing and monitoring requirements to ensure that the permit emission limits are met. For detailed emission calculation equations for all criteria pollutant emissions, please see Response 1-63 above, the revised Appendix B in the Final EIR, as well as the Draft EIR (pages 3-33 through 3-41).

The South Coast AQMD permit for Heater B-201 required monitoring and recording of the fuel rate and the fuel high heating value for the refinery fuel gas or natural gas used in the heater (Condition 1.26). By monitoring the fuel rate and the high heating value of the fuel, emissions can be easily calculated. In addition, Condition 232.1 required the installation and maintenance of a continuous emission monitoring device to accurately monitor the hydrogen sulfide concentration at the fuel inlet of the heater or by measuring SO_2 emissions at the outlet of the heater. Condition D328.1 required that the CO emission limit be monitored by either: (a) conducting a source test at least once every five years using AQMD Method 100.1 or 10.1; or (b) conducting a test at least annually using a portable analyzer and AQMD-approved test method. Therefore, monitoring for Heater B-201 was included as part of the South Coast AQMD permit. Heater B-201 was removed as part of the ULSD Project and is no longer operational. Therefore, permit requirements for source testing related to Heater B-201 are not applicable to the ULSD Project.

Source testing is required as part of the South Coast AQMD Permit for Heater B-401 and is described below.

- Permit Condition D28.21 requires source testing be conducted for NOx, SOx, ROG, CO, PM and PM10 within 120 days after achieving maximum production rate, but no later than 180 days after initial start-up. The source test was required to be conducted with the heater operating at least 80 percent of the permitted maximum capacity. In addition, the test for PM10 is required once every three years.
- Permit Condition D82.6 requires the operator to install and maintain a Continuous Emissions Monitoring System (CEMS) to measure SOx and O_2.
- Permit Condition D328.6 requires the operator to determine compliance with the CO emission limits by either conducting a source test once every five years or conducting a test at least annually using a portable analyzer and AQMD-approved test method.
- Permit Condition H23.37 confirms that 40 CFR 63, Subpart DDDDD applies to the VOC emissions associated with the operation of the heater. Under Subpart DDDDD, the U.S. EPA has promulgated national emission standards for hazardous air pollutants from three major source categories: Industrial boilers, commercial and institutional boilers, and process heaters. Compliance with Subpart DDDDD must be demonstrated using performance stack testing, fuel analysis or continuous monitoring systems. Site specific monitoring plans are required that address design, data collection, and quality assurance and quality control elements. All major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

- Heater B-401 is a major NOx and SOx RECLAIM source and operates with a CEMS for NOx and SOx.

As discussed above, the South Coast AQMD permit for B-401 requires source testing of Heater B-401 for NOx, SOx, ROG, CO, PM, and PM10 no later than 180 days after initial start-up, and requires CEMS for SOx and NOx, to demonstrate compliance with permit limits. In addition PM10 source test is required every 3 years and testing of CO periodically. Therefore, the South Coast AQMD permit requires monitoring and testing of Heater B-401 to ensure the permit limits are met.

The comment also asserts that basing post-project emissions on permit limits likely underestimates emissions increases, especially if the limits include exceptions for start-ups and shut-downs. Refer to Response 1-67 regarding start-ups and shut-downs.

Response 1-67

This comment asserts that NOx emissions from Heater B-401 were based on controlled emissions assuming the SCR unit is online and removing 90 percent of the NOx. The comment further asserts that the SCR is offline during start-ups and shut-downs of Unit 90, so if a start-up or shut-down lasted four hours, daily NOx emissions would increase from five to 12 pounds per day. The comment asserts that if the SCR is offline for an entire day, NOx emissions would increase from five to 50 pounds per day, thus contributing to NOx emissions that would exceed the South Coast AQMD's daily operational significance threshold for NOx.

As discussed in the Draft EIR, Heater B-401 was a functionally identical replacement of Heater B-201 (see Draft EIR, Page 2-7, 3rd paragraph). The installation of new Heater B-401 required the use of BACT so that an SCR unit was included as air pollution control for NOx emissions from new Heater B-401. Therefore, the project baseline emissions included the startup and shutdown of Heater B-201. Heater B-201 operated without an SCR unit at all times, including during start-up and shut-down.

The South Coast AQMD permit limits NOx emissions from Heater B-401 to 5 ppm. However, the South Coast AQMD permit limits on NOx and CO do not apply when Heater B-401 is in start-up or shut-down mode, during the refractory dryout period, or when the heater exhaust temperature is below 500 degrees F (NOx only). Heater B-401 operates with a CEMS, in compliance with RECLAIM regulations, which collects air emissions data on a continuous basis for NOx and SOx. RECLAIM data from the CEMS were evaluated for Heater B-401 to evaluate emission data during start-up and shut-down periods. RECLAIM emission data were evaluated for days when the operational status of the heater was more than "zero" hours but less than 24 hours. These are the days when start-up and shut-down operations occur. The average NOx emissions for fully operational days, when the SCR would be in full use, was 1.5 lbs/day. The average NOx emissions on start-up and shut-down days when the SCR would not be in full use was 1.8 lb/day. Therefore, emissions during start-up/shutdown were essentially the same as they were when the heater was in full operation. The reason for this is that the heater is operating at much less than full operation during start-up/shut-down days. When the heater is fully operational, the SCR is in full use and NOx emissions are fully controlled. In addition, the NOx emissions from Heater B-401 on the peak start-up/shut-down day (4.9 lbs/day on June 29, 2006 remained below the estimated peak NOx emissions of 5 lbs/day (4.96 lbs/day) in the EIR.

Minor revisions have been made to the emission calculations in the Draft EIR based on comments received on the Draft EIR. Those emissions are summarized in Table 16 below (which is a copy of the revised Table 3.3-7 in the Final EIR). As shown in Table 16, the revisions to the emission calculations for the ULSD Project are minor and would remain below the South Coast AQMD significance thresholds and would remain less than significant.

TABLE 16

ULSD Operational Emissions[1]

PROJECT COMPONENT	ULSD Project Emissions (lb/day)					
	CO	VOC	NOx	SOx	PM10	PM2.5
Pre-Project (Baseline) Emissions						
Fugitive Components	0	94.89	0	0	0	0
Heater B-201	22.64	4.53	30.50	2.5	4.85	4.85
Total Baseline Emissions	22.64	99.42	30.50	2.5	4.85	4.85
Project Emissions						
Fugitive Components	-	100.09	-	-	-	-
New Heater B-401[2]	6.04	5.44	4.96	4.19	5.83	5.83
Storage Tank 331	-	0.2	-	-	-	-
Increased SRP Use	5.77	0.81	3.40 to 19.78	0.38	0.61	0.61
Hydrogen Production	2.28 to 6.26	2.28 to 6.26	3.50 to 9.60	0.10 to 0.27	2.73 to 7.49	2.73 to 7.49
Trucks Transport	2.38	0.32	3.05	0.03	0.05	0.05
Electricity Demand	4.12	0.21	23.70	2.47	0.82	0.82
Steam Demand	0	0	0	0	0	0
ULSD Post -Project Emissions	20.59 to 24.56	109.35 to 113.32	38.60 to 61.08	7.17 to 7.34	10.04 to 14.80	10.04 to 14.80
Net Emissions Increase[2][3]	**-2.05 to 1.93**	**9.93 to 13.91**	**8.10 to 30.58**	**4.67 to 4.84**	**5.19 to 9.95**	**5.19 to 9.95**
SOUTH COAST AQMD SIGNIFICANCE THRESHOLDS	550	55	55	150	150	55
Significant?	NO	NO	NO	NO	NO	NO

(1) See Appendix B for detailed emission calculations. Differences in emissions in this table and Appendix B are due to rounding.
(2) A negative number indicates emission reductions.
(3) Post Project Emissions – Pre-Project (Baseline) Emissions.

Response 1-68

This comment asserts that because CO and VOC emissions are combustion byproducts they are directly related to each other. The comment states further that, according to the Draft EIR, pre-project CO emissions from Heater B-201 are four times higher than post-project emissions from Heater B-401, while pre-project VOC emissions from Heater B-201 are less than post-project VOC emissions from Heater B-401. The comment states further that the Draft EIR shows that CO emissions for Heater B-401 decline compared to Heater B-201 even though no CO emission control technologies have been required. According to the comment, these results appear to call into question pre-project and post project heater emission estimates. This assertion was previously made in comment 1-62; therefore, refer to Response 1-62 for the derivation of the emission factors used for Heaters B-201 and B-401, which support the daily emissions data for each heater. As discussed in Response 1-62, the South Coast AQMD required the new Heater B-401 to meet BACT standards (South Coast AQMD Rule 1301(a)(1) BACT, 5-10-1996) for new heaters, and the CO BACT standard imposed on the replacement Heater B-401 is more stringent than the requirements for old Heater B-201. The Title V operating permit limits CO emissions from Heater B-401 to a maximum of 10 ppmv (see Response 1-65, Table 15, and Attachment 3 to the Responses to Comments) or 0.25 lbs/hour. The detailed emission calculation is provided in Response 1-62 and in Appendix B of the Final EIR. The CO emissions are limited by enforceable permit conditions, as described in Responses 1-62 and 1-63, and permit conditions require confirmation testing and monitoring, as described in Responses 1-66.

Response 1-69

This comment asserts that pre-project emissions from Heater B-201 are based on peak daily emissions, but should be based on average daily emissions or even minimum daily emissions. The District's regional significance thresholds are based on peak-day emissions. Thus, for example, the regional significance threshold for NOx is a 55 lb/day increase in peak day emissions. The District measures this increase from the baseline of the peak day before the project to the peak day after the project is implemented. The commenter argues that the only appropriate comparison is from a baseline of average or minimum daily emissions to the peak day after the project is implemented. This is incorrect. As discussed in Response 1-9, the District's approach is consistent with the Clean Air Act and associated health-based science, and is supported by substantial evidence.

Under the Federal Clean Air Act, U.S. EPA establishes "National Ambient Air Quality Standards" (NAAQS) for various widely-dispersed pollutants. 42 U.S.C. Section 7409. Each state must adopt and implement a state implementation plan containing enforceable measures and other techniques to achieve and maintain the NAAQS. 42 U.S.C. Section 7410. The U.S. EPA sets each of the NAAQS based on extensive assessments of the health effects associated with exposure to a particular pollutant. Many of the NAAQS have an averaging time of 24 hours or less because EPA determined that adverse health effects result from short-term exposure. (See, e.g. nitrogen dioxide, 75 Fed.Reg. 6474, 6502). These NAAQS ensure protection of public health as long as the ambient concentration of a particular pollutant on the worst day is less than the NAAQS. Therefore, to determine if the project will have a significant effect on air quality, the District is concerned with whether conditions after project implementation are more or less likely than conditions before the project to cause an exceedance of the NAAQS. Since many of the NAAQS are based on short term exposures (24 hours or less), the greater the emissions on the worst day, the higher the likelihood of causing an exceedance of the NAAQS. Thus, the increased likelihood of causing an exceedance, if any, depends on the emissions on the worst day before the project compared to the emissions on the worst day after the project.

Using the average day as the baseline, and comparing it to the peak day, as recommended by the commenter, would cause an inaccurate result. For example, in 2010 EPA adopted a 1-hour NAAQS for nitrogen dioxide (NO_2) of 100 parts per billion ("ppb"). (Primary National Ambient Air Quality Standards for Nitrogen Dioxide, 75 Fed. Reg. 6474 (Feb. 9, 2010). The District is thus concerned with whether emissions after the project are more or less likely to exceed the NAAQS of 100 ppb than emissions before the project. Since an exceedance is based on the worst day, also known as a peak day, the answer depends on whether peak day emissions are higher or lower after project implementation, not whether the peak day after the project is higher than the average day before the project. For example, assume peak day emissions before the project are 35 lbs per day of NOx, and average day emissions are 20 pounds per day. After the project, the peak day emissions are 30 lb per day and the average day emissions remain at 20 lb per day. A comparison of peak day to peak day emissions reveals that conditions after the project are actually less likely to cause an exceedance of the daily or shorter standard than emissions before the project (30 compared to 35). But the commenter's approach would make it artificially appear that emissions after the project (peak day 30 lbs per day) are more likely to cause an exceedance than conditions before the project (average day of 20 lbs per day). Thus, the District's approach is consistent with its identification of the likelihood of a NAAQS exceedance as the relevant metric, whereas the commenter's approach would misleadingly identify many projects as more likely to cause an exceedance when in reality they are not.

Another simple analogy shows how the methodology advocated by the comment would produce a false and misleading conclusion. Assume a man eats an average of one egg per day, and so the actual daily consumption ranges from zero eggs to three eggs. He may replace the stove, but does not change his breakfast habits or egg consumption. A comparison of pre-project minimum day (0) to post-project peak day (3) would suggest that replacing the stove caused the man to increase his egg consumption by three eggs per day. A comparison of pre-project average day (1) to post-project peak day (3) would suggest that replacing the stove caused an increase egg consumption of two eggs per day. Both of these comparisons would be false and misleading, because the egg consumption did not change at all. This analogy demonstrates the importance of using same or similar time periods or data sets when trying to make comparisons to identify the impacts ***caused*** by a project. Depending upon the significance threshold applicable to a particular topic, it may be appropriate to compare peaks to peaks, averages to averages, or minimums to minimums, but comparisons across different time periods leads to false conclusions. Here, the relevant significance threshold is peak day, and so the pre-project peak daily emissions are compared to the post-project peak daily emissions to determine the effect of the Project.

Accordingly, in the Draft EIR (see Page 3-1 and 3-2), actual peak daily emissions for the 2002-2003 timeframe is considered to be the pre-ULSD Project or baseline conditions for Refinery operations as this represents the timeframe prior to construction or operation of the ULSD Project. The pre-project peak day is then compared to the post-project peak daily emissions (based on maximum potential to emit allowed by the permit) to determine the emissions increase resulting from the project.

The comment tries to support its criticism of the EIR's methodology by observing that the EIR calculates a decline in CO emissions as a result of the project, but – according to the comment – there is no reason for such a decline. The premise of the comment is incorrect. The new Heater B-401 is required to meet low CO emissions standards that did not apply to the older Heater B-201 Baseline emissions for Heater B-201 were based on the actual, peak operating day during the 2002-2003 timeframe. As discussed in Response 1-62, the South Coast AQMD requires the new Heater B-401 to meet BACT standards (South Coast AQMD Rule 1301(a)(1) BACT, 5-10-1996) for new heaters, and the CO BACT standard imposed on the replacement Heater B-401 is more stringent (10 ppmv) than the requirements for old Heater B-201 (400 ppmv CO). These requirements and corresponding emissions are reality in the post-project period, as new heaters have been engineered to meet the more stringent regulatory requirements and come with manufacturer's guarantees for emission limits. The Title V operating permit limits CO emissions from Heater B-401 to a maximum of 10 ppmv (see Attachment 3 to the Responses to Comments) or 0.25 lbs/hour. The detailed emission calculation is provided in Response 1-62 and in Appendix B of the Final EIR.

The comment also again states that without continuous emissions monitoring of CO emissions there is no assurance that the post-project CO limit of 6.04 pounds per day would be achieved. With regard to ensuring compliance with permit limits imposed on the equipment that are part of the ULSD Project, as discussed in Response 1-66, the South Coast AQMD permit for B-401 requires source testing and CEMS for CO and NOx, to demonstrate compliance with permit limits. Therefore, the CO limit of 10 ppm (resulting in a maximum emission rate of 6.04 lbs/day) is enforced.

The comment concludes by stating that the correct value for pre-project or post-project CO emissions cannot be determined because the Draft EIR did not include daily heat rate, daily CO emissions data for the pre-project period, and the actual permit conditions assumed to control CO emissions. Daily pre-project CO emissions data for Heater B-201 are provided in the table at the top of page B-3 in Appendix B. The emission factors used, the maximum firing rate and the heat content of the emission calculations have been added to the heater emissions calculations in the Final EIR, Appendix B for ease in reviewing the calculations. As demonstrated in this response, the CO emission factors used in the Draft EIR are appropriate because of the 10 ppm permit limit imposed on Heater B-401. The emission factors used by the commenter in Table 4 are incorrect because they are "based on the same ratio of pre- to post-emissions as assumed for VOC, PM10 and PM2.5" which did not account for the more stringent CO limit imposed on Heater B-401.

Response 1-70

This comment asserts that the same emission factors were used to determine pre- and post-project VOC, PM10, and PM2.5, but that there is no evidence these emission factors accurately represent post-project emissions on the peak day. The comment further asserts that the Draft EIR should have provided stack test data.

A source test in December 2014 indicated that PM10 emissions from Heater B-401 were 0.129 lbs/hr (3.1 lbs/day), which is well below the peak PM10 and PM2.5 emissions estimate of 5.4 lbs/day presented in the EIR. A source test in April 2012 indicated that CO emissions from Heater B-401 were 7.88 ppmv, which is below the 10 ppmv that the peak CO emissions estimate in the EIR were based on. These test results show that – if anything – the 2014 Draft EIR overestimated the emissions associated with the project.

Although the commenter is critical of South Coast AQMD-approved emission factors, she provides no suggestions, data, or other information regarding emission factors that should have been used in the Draft EIR. The commenter does recommend that emission factors should be based on stack tests as a fair estimate of peak day emissions. Since stationary source equipment rarely operates at peak capacity, stack test data would show actual emissions rather than peak daily emissions. Therefore, using stack test data would provide a less conservative estimate of emission impacts compared to using South Coast AQMD-approved emission factors.

Finally, this comment asserts that PM10 and PM2.5 emissions were underestimated because they didn't account for ammonia slip emissions. Ammonia slip is unreacted ammonia in the exhaust that slips through the SCR catalyst, which reacts with SO2 to form SO3 and then reacts downstream to form ammonium sulfates, which are components of PM10 and PM2.5. As shown above, the PM10 and PM2.5 emissions based on source tests (which include the operation of the SCR and ammonia slip) were well below the peak PM10 and PM2.5 emissions estimated in the EIR. Also, as shown in Attachment 3, particulate matter emissions are limited by South Coast Air Quality Management District Rules 404 and 409.

In comments on the 2005 Draft Subsequent Negative Declaration, Dr. Fox raised the same issues, alleging that PM10 and PM2.5 emissions were underestimated because the calculations overlooked secondary particulate formation due to ammonia slip and oxidation of SO_2. See comments 1-11, 1-23 and 1-24 on 2005 Draft Subsequent Negative Declaration. The South Coast AQMD provided responses to these comments in the 2005 Final Subsequent Negative Declaration. These purported deficiencies were also alleged in the lawsuits challenging the 2005 Final Subsequent Negative Declaration. See the Thirteenth Cause of Action in the Fourth Amended Petition of Valdez et al. v. South Coast AQMD. These issues were either abandoned by the petitioners or rejected by the Superior Court or Court of Appeal. Therefore, these issues cannot be raised at this time, and the South Coast AQMD is not obligated to respond to the comment.

<u>Response 1-71</u>

This comment again asserts that baseline emissions for Heater B-201 were based on maximum rated capacity during the pre-project period, years 2002 to 2003, and that the correct baseline for Heater B-201 should be actual average emissions. This comment is incorrect. Baseline emissions were based on <u>actual</u> peak daily emissions, not on maximum rated capacity, as suggested in the comment. The maximum rated capacity was only used to calculate post-project emissions from Heater B-401. With regard to deriving pre-project emissions from Heater B-201, refer to Responses 1-9 and 1-69.

The comment also asserts that there is a long line of Court of Appeal decisions that hold that "impacts of a proposed project are compared to 'actual' conditions at the time of the CEQA analysis, not the level that could have or should have been present, e.g., 'the maximum rated capacity.'" The comment doesn't actually cite any Court of Appeal decisions. It should be noted that in *CBE v. SCAQMD* the California Supreme Court stated, "[T]he date for establishing baseline cannot be a rigid one. Environmental conditions may vary from year to year and in some cases it is necessary to consider conditions over a range of time periods. In some circumstances, peak impacts or recurring periods of resource scarcity may be as important environmentally as average conditions." 48 Cal.4th at 328. As explained in Responses 1-9 and 1-69, the U.S. EPA and State of California established ambient air quality standards based on human health science (see Table 3.1-1 of the Final EIR), which in some cases incorporate short exposure timeframes to address the specific health consequences of short term exposure for that pollutant, e.g., nitrogen dioxide has an average annual standard, as well as a 1-hour average standard. 48 Cal.4th at 328. For additional information on establishing the baseline for the ULSD Project see Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, and 1-73.

<u>Response 1-72</u>

This comment asserts that the South Coast AQMD's significance criteria determine how both the pre-project and post-project emissions are calculated. The South Coast AQMD's air quality significance thresholds were developed and adopted by the South Coast AQMD's Governing Board because they represent emissions that have an effect on air quality or are levels that pose a threat to human health. Limited guidance on analyzing direct air quality impacts can be found in the 1993 Handbook, but the primary guidance for analyzing direct and indirect air quality impacts can be found online at: http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook. For additional information on South Coast AQMD significance thresholds, refer to Responses 1-43 and 1-44. With regard to developing the baseline for the ULSD Project, the Supreme Court noted statements of the South Coast AQMD and Phillips 66 that refinery operations are complex and variable. 48 Cal. 4th at 327. The Supreme Court left to the South Coast AQMD's discretion the technical questions regarding how to measure the baseline for existing refinery operations, so long as it is supported by substantial evidence. 48 Cal. 4th at 327, 328. For additional information regarding establishing the baseline for the ULSD Project, refer to Responses: 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, 1-69, and 1-73. With regard to establishing the baseline specifically for Heater B-201 and emissions for Heater B-401, refer to Responses 1-62 and 1-63.

Response 1-73

In this comment it is asserted that 2002 and 2003 may be reasonable years for establishing the baseline, but use of peak daily emissions during this timeframe does not provide a valid approach for establishing the baseline. With regard to establishing the baseline in general, refer to Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-48, 1-50, 1-53, and 1-69. With regard to establishing the baseline specifically for Heater B-201, refer to Response 1-69.

The comment asserts further that the Draft EIR did not contain any information used to select peak daily emissions of CO, VOC, NOx, SOx, PM10, or PM2.5 during 2002 and 2003 for Heater B-201. In addition, the comment states that the EIR should have included "…continuous emission monitoring data, reported on at least an hourly basis, for heat rate (mmBtu/hr), NOx, and perhaps CO." With regard to data used to derive the pre-project emissions for Heater B-201, refer to Response 1-69. The Draft EIR for the ULSD Project complies with CEQA Guidelines §15147 by including daily emission rates for Heater B-201, which is a subset of more detailed emissions data, in Appendix B of the EIR. For further clarification, the CEMS data used to determine the peak day for the baseline period of 2002-2003 is included as Attachment 1 to the Responses to Comments.

Finally, the comment speculates that in some cases an applicant may temporarily increase (spike) operations artificially to establish a higher baseline. The comment presents no evidence that this is the case for the ULSD Project. Table 3.1-3 of the 2014 Draft EIR shows Reported Criteria Pollutant Emissions from the refinery from 2000 through 2013. The emissions data vary from year to year, but do not show any artificial jump in 2002-2003.

Response 1-74

This comment asserts that the method used to calculate the increase in electricity demand is not clearly explained in the Draft EIR and that the increase in electricity is from certain unspecified equipment. However, as noted in the comment, page 3-35 does specify the equipment that contributed to increased electrical demand stating, "The installation of pumps, fans and air coolers resulted in an increase in electricity use at the Refinery (about 835 horsepower (HP)). In addition to the pumps, Phillips reactivated a 200 HP recycle gas compressor in Unit 89 (jet hydrotreater), as Unit 89 and Unit 90 could no longer share a compressor. Therefore, the total increase in electricity usage was 1,035 HP or about 18,623 kilowatt-hours per day."

The comment then questions whether or not the total horsepower rating includes all new equipment. In order to calculate emissions from the ULSD Project for increased electricity demand, the most important piece of data is the total increase in horsepower from the new equipment. Once the total daily horsepower is known, kilowatt-hours per day, and thus emissions, can be calculated. Table 17 shows the existing electrical demand and the project electrical demand for specific components. All of the equipment identified in the "Baseline" Column of Table 17 has been physically removed, with the exception of the injection water pump in Unit 89 (G-106/S). This pump is used approximately once per week, therefore, the injection water pump has been added into the ULSD Project electricity use and the emission calculations have been revised to include its operation.

The comment notes that the ULSD Project includes doubling the capacity of the recycle gas compressor (Draft EIR page 2-7). Referencing the Draft EIR's statement on page 3-35 that Phillips reactivated a 200 hp recycle gas compressor, the comment speculates that the recycle gas compressor should have been 400 hp instead of 200 hp. In fact, the reactivated compressor was doubled in size from 100 hp to 200 hp. For clarity, the Final EIR has been modified to identify the horsepower rating of the recycle gas compressor.

TABLE 17

Electricity Changes Associated with the ULSD Project

Component		Baseline(1) (hp)	Post - Project (hp)	Description
Unit	Item No.			
U-89	G-106/S	20	20	Injection Water Pumps
U-90	G-202	450	-	Reactor Charge Pump
	G-209A/B	75	-	Cooling Tower Circulation Pumps
	G-402	-	700	New Reactor Charge Pump
	G-406A/B	-	40	New Injection Water Pumps
	G-409A	-	150	New Cooling Tower Circulation Pump
	G-409C	-	150	New Cooling Tower Circulation Pump
	E-221AM	40	-	Cooling Tower Fin Fan Motor
	E-221BM	40	-	Cooling Tower Fin Fan M otor
	CT-401AM	-	100	New Cooling Tower Fin Fan Motor
	CT-401BM	-	100	New Cooling Tower Fin Fan Motor
	E-404AM	-	30	New Hot Vapor Air Cooler Fin Fan Motor
	E-404BM	-	30	New Hot Vapor Air Cooler Fin Fan Motor
SCR			16	New Ammonia Injection System
Offsite	P-4355	15	20	New Jet Blendstock Pump
	P-5131	-	75	New Jet Blendstock Pump
	P-5132	-	75	New Diesel Blendstock Pump
	P-5129/5130		5	New Jet Sample Pumps
	GB-101	-	200	New Compressor
	Total Power:	640	1,711	

(1) All of the equipment listed in the baseline column was removed as part of the ULSD Project with the exception of G 106/S. This pump is operated approximately once per week and its electricity use has been added into the project.

Response 1-75

This comment cites the 2014 Draft EIR project description, which states that the ULSD Project includes a new ULSD shipping pump, two new pumps for handling jet and diesel blendstocks, and one new pump to create separate facilities for handling jet and diesel fuel (Draft EIR page 2-8). Further, the comment asserts that a vaporization unit (air heater and air blower) would be required to supply ammonia vapor to the SCR system, but was not included as part of the analysis of increased electricity demand and by itself could exceed the 835 hp total for pumps, fans, and coolers. As discussed in the Draft EIR (see page 2-8, last paragraph), it should be noted that, while there is a new shipping pump to handle the ULSD, there has been a corresponding reduction in use of the existing pump, which no longer is used to ship diesel. The reduction in use of the existing (original) shipping pump was not included in the calculation of electricity demand for the ULSD Project, providing a conservative (overestimate) of the increase in electricity demand by not crediting the reduction in electricity from the pump no longer used to ship diesel as a result of the project.

This comment then identifies the total increase in horsepower rating from the ULSD Project from pumps, heaters, and air coolers, 835 hp, and from the recycle gas compressor, 200 hp (835 + 200 = 1,035 hp). The comment then goes on to say that Appendix B presents the information differently, specifically, pre-project horsepower, 640 hp, plus the post-project horsepower increase, 1,035 hp, for a total electricity demand of 1,675 hp, resulting in a net increase in horsepower of 1,675 hp -645 hp = 1,035 hp. Based on this information, the commenter suggests that the increase in horsepower is not just new equipment. The table at the top of page B-5 in Appendix B of the Draft EIR shows the pre-project horsepower rating, 640 hp, plus the total electricity demand of 1,675 hp. Showing pre-project horsepower and total horsepower provides additional information regarding the overall horsepower rating associated with the ULSD Project. Using either approach the result is the same, that is, increased electricity demand is based on an increase horsepower from the ULSD Project of 1,035 hp as reported in the Draft EIR. The estimated electricity usage has increased slightly in the Final EIR as one pump in Unit 89 was not removed (20 hp) as part of the ULSD Project and the electricity use associated with the ammonia injection system has been added to the estimated project electricity use (see Response 1-74 for further information on electricity use). Therefore, the estimated electricity use for the ULSD Project is based on the maximum electricity use associated with the new or modified equipment of 1,071 hp (1,711 – 640 hp). This represents the maximum potential increase (peak) and would assume all equipment is operating at its maximum rate 24 hours per day, 7 days per week, and 365 days per year which overestimates the actual use. For the analysis of maximum or peak ULSD electricity demand, impacts were based on the change (or delta) from the pre-project horsepower rating to the post-project rating for all components that are part of the ULSD Project, as noted by the comment, which is consistent with CEQA Guidelines §15125(a) and §15126.2. As explained in the EIR (Page 3-35), the emissions associated with the increased use of electricity were calculated using the peak electricity demand and emission factors in the South Coast AQMD CEQA Air Quality Handbook (also see EIR Appendix B for emissions calculations and South Coast AQMD, 1993). The emission increases associated with the increase in electrical use at the Refinery associated with the ULSD Project were: CO 4.1 lbs/day, VOC 0.2 lbs/day, NOx 23.7 lbs/day, SOx 2.5 lbs/day, PM10 0.8 lbs/day, PM2.5 0.8

lbs/day. See Response 1-74 for further details on the electricity use associated with the ULSD Project.

Response 1-76

In this comment it is asserted that pre-project electricity demand is not supported in the record because the Draft EIR does not explain how pre-project horsepower rating of 640 hp was selected or what equipment this rating represents. Further, the comment questions how the pre-project horsepower rating was selected, that is, is it an average day or peak day horsepower rating? The comment also asserts that the Draft EIR simply states the horsepower rating of groups of equipment without providing a process and instrument diagrams, other process diagrams that show how electrical equipment fits into the over process, or vendor specification sheets to confirm the horsepower ratings. See Response 1-74 for further details on the electricity use and the specific equipment that was removed and added associated with the ULSD Project. The increase in electricity use was based on the change (incremental increase) in the electricity demand associated with the project. As stated in Responses 1-74 and 1-75, the emissions associated with electricity are based on peak day use and assumes the equipment operates at maximum rating 24 hours per day, 365 days per year.

The Draft EIR fulfills its obligation as an information document by identifying the total increased horsepower rating from the ULSD Project, which can then be converted into emission impacts. Horsepower ratings are specified in the refinery permit applications. Refineries are subject to periodic inspections, so if equipment with a different horsepower rating than what is listed on the permit application is being used, refinery operators would receive a notice of violation and, potentially, would be subject to fines or other penalties.

Response 1-77

This comment asserts that the Draft EIR underestimates the increase in electricity demand from the ULSD Project because it only includes increased demand from new equipment, not existing equipment nor from cooling water necessary to support the project. The comment then uses Unit 90 and supporting equipment as an example of new and existing equipment that require additional electricity. With regard to equipment associated with the ULSD Project that contributes to increased electricity demand, refer to Response 1-74.

This comment then cites previous comments submitted on the 2004 CEQA document for the ULSD Project (Exhibit 2), which also claimed that increased electricity demand and, therefore, emissions from increased electricity demand were underestimated. The comment includes Table 3 that shows increased electricity demand emissions from the 2014 Draft EIR and the purported emissions based on the following. The comments submitted on the 2004 CEQA document based the electricity demand on removing 7,400 pounds per day of sulfur, resulting in an electricity demand of 34,287 kwh/day. For the analysis in the Draft EIR, the commenter calculates that the ULSD Project removes 4,700 pounds per day of sulfur. Using a ratio between sulfur removed as identified in the 2004 comments and the current estimate of sulfur removed, the comment then claims that additional electricity demand from the sulfur removal process would be 21,800 kwh/day compared to 18,623 kwh/day identified in the Draft EIR.

The Final EIR has been revised to add in the incremental increase in electricity use at the Sulfur Plant associated with the ULSD Project, as discussed in Response 1-46. The estimated increase in sulfur production was a maximum of 4,874 lbs/day sulfur, or 5,083 lbs/day of hydrogen sulfide. The estimated increase in electricity use is 0.3kW-hr/lb H_2S or a maximum increase of 1,524 kW-hr/day. As shown in Table 8 (Response 1-46), the estimated increase in emissions associated with the increase electricity use at the Sulfur Recovery Plant were 0.3 lb/day of CO, 0 lb/day VOC, 1.7 lbs/day NOx, 0.2 lb/day SOx, 0 lb/day PM10, and 0.1 lb/day PM2.5. These minor emission increases have been included in the Final EIR.

While a theoretical increase in electricity associated with the ULSD Project has been calculated and included in the EIR, it should be noted that the overall electricity use associated with the refinery operations did not increase. In the pre-project period of 2002-2003, the electrical consumption for the Refinery averaged 8.0 kw-hr/bbl of feed. In the post project period of 2006-2008, electrical consumption averaged 7.8 kw-hr/bbl of feed.[16] Therefore, there is no indication that the ULSD Project increased electrical demand at the Refinery or downstream units.

<u>Response 1-78</u>

This comment notes that previous analyses of the ULSD Project identified potential increased NOx emissions from steam boilers to support steam demand for the recycle gas compressor. The analysis in the Draft EIR describes the integrated steam system in place at the Refinery which in fact avoided the need to increase steam production (and associated emissions) to supply steam for the ULSD Project. The comment asserts that the 2014 Draft EIR does not contain any information to support the conclusion that the ULSD Project will not result in increased steam generation or associated emissions. The South Coast AQMD disagrees with this assertion for the following reasons. First, as noted in the comment, the integrated steam system is described in detail in the 2014 Draft EIR on pages 3-36 through 3-39. Additional information on the integrated steam system is provided in the following paragraphs.

The 2004/2005 CEQA documents did not closely examine the details of the design or operation of the refinery's steam generation system because, as was noted in the 2004 CEQA document, the steam could be supplied by the existing boilers at the Wilmington Plant without modifications to the boilers or permit conditions. Therefore, the South Coast AQMD considered continued operation of the steam generating equipment within its permit limits to be part of the baseline, and did not consider it necessary to calculate emissions associated with steam generation.

In Response to Comments, however, the South Coast AQMD made a theoretical calculation based on hypothetical, worst case assumptions. First, the South Coast AQMD assumed that, pound for pound, the steam needed for the project would be new steam produced by operating

[16] The electricity usage is based on metered usage that includes purchased electricity, as well as electricity produced by Phillips 66 from their Cogen Unit. The total barrels of process input, includes crude oil plus intermediate feedstocks as reported to the CEC and EIA. This calculation was completed for the baseline 2002-2003 period and the post-project period (2006-2008).

the existing steam generating equipment more. Second, the South Coast AQMD assumed that this additional steam would be produced by the piece of equipment with the highest potential emissions to estimate "worst-case" emissions impact. The South Coast AQMD reported that refineries operate 24 hours per day, seven days per week, unless units are temporarily shut down for maintenance. Steam is required to operate the major refinery units on a continuous, 24-hour basis. Therefore, in order to provide safe operating conditions, the steam system at Wilmington Plant is sized such that sufficient steam to operate all refinery units can be supplied to all units even when one unit is shut down for maintenance or repair. The refinery continuously adjusts the load between all steam generating equipment based on the immediate steam demand of the refinery and the complement of steam generating equipment in operation at that time. On a routine basis, it is expected that steam would be generated from the Cogeneration Unit and the newer boilers. But for the Responses to Comments on the 2004/2005 CEQA documents, the South Coast AQMD assumed that the steam needed for the project would be met in isolation by Boiler 4 and that as a "worst-case" assumption all other steam generating equipment would be down for maintenance. This was considered to be a "worst-case" analysis because Boiler 4 is the oldest boiler with the highest emissions.

Subsequent to 2004, the Refinery operators have performed a more thorough evaluation of how the ULSD Project is realistically supplied with steam by refinery steam-generation equipment at the Wilmington Plant, and how such equipment is integrated with overall refinery operations. As a result, the Draft EIR contains a much more detailed description of steam production, and provides a more realistic picture of actual steam production from the four boilers and one cogeneration unit based on actual, not theoretical conditions in which steam is generated (see Final EIR pages 3-39 through 3-42). The analysis is grounded in fact, specifically, the engineering design of the system; it is not a "theory" as characterized by the commenter.

Steam production data, together with other data relating to Refinery operations, confirms that the ULSD Project did not cause an increase in Refinery steam production. The steam production process at the Refinery is complex and integrated, and data is not available that isolates steam production and consumption by unit and pressure of steam. Therefore, to confirm the analysis based on engineering design, steam production was calculated per barrel of Refinery throughput during the pre-project and post-project periods.[17] Using the fuel fired in the four boilers and cogeneration unit, the pre-project and post-project steam production was calculated as follow:

Pre-project (2002-2003): 147.9 MMbtu/1000 bbl feed

Post-project (2006-2008): 147.7 MMbtu/1000 bbl feed

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[17] Total steam production cannot be used alone to determine whether the ULSD Project caused an increase in refinery steam production because steam production can fluctuate for reasons unrelated to the ULSD Project. As explained in Response 1-54, refinery operations fluctuate with market conditions. Changes in crude throughput rates and production of fuels would result in changes in steam production. The ULSD Project was designed to meet federal and state regulations requiring reductions in the amount of sulfur in diesel fuel; it did not increase diesel production or the Refinery's overall throughput or capacity. In order to isolate any changes in steam production caused by the ULSD Project from changes in steam production due to changes in throughput, the total steam production must be divided by the amount of material processed to determine whether more steam was required ***per barrel*** of feed, comparing the pre-project and post-project periods.

This data and calculation confirm that steam production at the Refinery did not increase as a result of the ULSD Project. When looking at the boilers and cogeneration unit with respect to steam demand, the equipment was running essentially the same prior to and following implementation of the ULSD Project, consistent with the conclusion that there was no increase in steam demand associated with the ULSD Project. Therefore, the analysis in the Draft EIR is grounded in facts regarding the design and operation of the refinery's steam generation system. These facts constitute substantial evidence, as directed by the California Supreme Court.

The comment asserts that the Draft EIR doesn't contain information such as material balances and process flow diagrams that support operation of the integrated steam system. However, a flow diagram of the steam system at Phillips 66 was included in the Draft EIR (see Draft EIR, Figure 3-1, page 3-38). As noted in CEQA Guidelines §15121(a), "An EIR is an information document which will inform public agency decision makers and the public generally of the significant environmental effect of a project…" The EIR for the ULSD Project fulfills this obligation.

Response 1-79

The comment states again that the 2014 Draft EIR should not have used 2006-2008 as the post-project period due to the recession. This assertion is not supported by fact and, therefore, is incorrect. The Draft EIR provides detailed discussions on the rationale for selecting 2002 to 2003 as the pre-project period and 2006 to 2008 as the post project period. See Draft EIR at p. 3-2. For additional information on choosing the pre-project period refer to Responses 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, 1-73. For additional information on choosing the post-project period refer to Responses 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76. In addition, in arguing that use of 2006-2008 as the post-project period results in an underestimate of the emissions associated with steam production, the comment states that the maximum steam demand of the compressor should be used to calculate emissions. This statement completely ignores the basis for the analysis in the 2014 Draft EIR. That analysis is based on the engineering design of the equipment, and so is not affected by the Refinery throughput at any given time. As discussed in detail in the 2014 Draft EIR (see pages 3-36 through 3-39), as well as Response 1-80, the design of the integrated steam system at the Wilmington Plant avoids any increase in steam production in order to support the project changes at Unit 90. The Wilmington Plant operates an integrated steam system. As is typical for refineries, the Wilmington Plant uses steam at three different pressures: 400 pounds per square inch (psi) steam (high pressure system), 150 psi steam (medium pressure system), and 20 psi steam (low pressure system). Different equipment in the Refinery requires one or more of these different pressures of steam to operate. However, the four steam boilers and cogeneration plant produce steam at only one pressure, 400 psi. As shown in Draft EIR, Figure 3-1 (see page 3-38), there are two ways that 400 psi steam is reduced to 150 psi steam. First, a portion of the 400 psi steam passes through units requiring 400 psi steam, where some of the energy in the steam is put to work, and then the steam (now at lower pressure) is directed into the header for the 150 psi steam system. Second, some of the 400 psi steam passes to the 150 psi steam system directly through one of four letdown valves, where the pressure is deliberately reduced to maintain 150 psi. The boilers and cogeneration plant always produce more 400 psi steam than is needed for the units that use 400 psi steam, and this additional 400 psi steam is reduced through letdown valves and sent to the 150 psi system.

However, as part of the ULSD Project, the existing recycle gas compressor GB-301 mentioned in Comment 1-79 was modified to increase its capacity. The recycle gas compressor capacity doubled, but this did not result in a corresponding increase in steam generated by the boilers and cogeneration unit at the Wilmington plant. The recycle gas compressor in Unit 90 uses predominantly 400 psi steam. Given the integration between the 400 psi and 150 psi steam systems, if Unit 90 requires more 400 psi steam, any increased demand for steam is met by merely diverting 400 psi steam from the letdown valves to Unit 90. Within Unit 90, the 400 psi steam is put to work in the recycle gas compressor, and then it is exhausted to the 150 psi steam header for use elsewhere in the refinery. Thus, energy in the 400 psi steam is used in Unit 90, instead of passing the excess 400 psi steam through the letdown valves to produce 150 psi steam. The same amount of 400 psi steam is produced by the four refinery steam boilers and cogeneration unit, but there is a shift in the allocation of steam between the two pathways to the 150 psi system. More of the steam passes through Unit 90 to get to the 150 psi system and less of the steam passes through letdown valves to get to the 150 psi system, but the same amount of steam is being generated. In other words, since the 150 psi system creates the demand for steam, the increase in steam for Unit 90 merely shifts the path of the steam to travel through Unit 90 as opposed to the letdown valve. See the 2014 Draft EIR (see pages 3-36 through 3-39), as well as Response 1-80 for further details on the steam demand for the refinery and the proposed project. Moreover, the corroborating calculation presents steam production per barrel of throughput, allowing accurate comparisons even though the Refinery was operating at somewhat different throughputs in the pre-project and post-project periods.

Response 1-80

This comment states that using steam demand data for the entire Refinery could obscure increases required for the ULSD Project, if temporary decreases occurred elsewhere. The comment ignores the fundamental analysis in the 2014 Draft EIR, which is that the design of the integrated steam system at the Wilmington Plant avoids any increase in steam production in order to support the project changes at Unit 90, and that the steam production information is included as a secondary, corroborating source. As discussed in detail in the 2014 Draft EIR (see pages 3-36 through 3-39), as well as Response 1-79, the design of the integrated steam system at the Wilmington Plant avoids any increase in steam production in order to support the project changes at Unit 90. The Wilmington Plant operates an integrated steam system, designed to handle variable steam demand from numerous units and equipment at any given time. The recycle gas compressor in Unit 90 uses predominantly 400 psi steam. Given the integration between the 400 psi and 150 psi steam systems, if Unit 90 requires more 400 psi steam, any increased demand for steam is met by merely diverting 400 psi steam from the letdown valves to Unit 90. Within Unit 90, the 400 psi steam is put to work in the recycle gas compressor, and then it is exhausted to the 150 psi steam header for use elsewhere in the refinery. Thus, energy in the 400 psi steam is used in Unit 90, instead of passing the excess 400 psi steam through the letdown valves to produce 150 psi steam.

In fact, the conclusion of the 2014 Draft EIR that there would be no increase in steam produced, based on the facts of engineering design, is corroborated indirectly through two different data sets. First, steam production data and throughput data were used to calculate a Refinery-wide value of steam per barrel of throughput refined in the pre-project and post-project periods. A comparison of the pre-project and post-project periods does not indicate any increase in steam consumption per barrel of throughput. Accordingly, nothing in this data set calls into question the conclusion based on engineering design. Second, data from the steam letdown valve was examined, and it confirms that at all times during the pre-project and post-project periods, 400 lb steam was passing through the letdown valve, meaning that 400 lb steam was being produced for the sole purpose of feeding the 150 lb steam header. This confirms that conditions existed in which 400 lb steam could be redirected from the letdown valve to Unit 90 and used productively in that unit before discharging to the 150 lb steam header, supporting the new steam demand of Unit 90 with no additional production of steam. These are precisely the conditions described based on the engineering analysis. Both sets of data and calculations show that there is no factual basis to question the analysis based on engineering design. The comment provides no facts to the contrary.

Response 1-81

This comment notes that the Draft EIR includes a mitigation measure to demonstrate that continued operation of the ULSD Project will not cause steam demand to increase. The comment then asserts that the mitigation measure will not assure that the project does not increase emissions from steam production for three reasons. The South Coast AQMD disagrees with each of the assertions relative to the effectiveness of the mitigation measure identified in the comment for the following reasons.

First, the comment notes that the duration of the mitigation measure is “only” five years. It should be pointed out that the Draft EIR demonstrated that ULSD emissions would not be significant and that additional steam demand for the ULSD had no effect on steam production in the Refinery and, thus, caused no ULSD Project emissions. Therefore, no mitigation is required under CEQA. Five years is a reasonable time for the duration of the mitigation measure for the following reasons. As noted in the 2014 Draft EIR and numerous Responses to Comments contained in this attachment, refinery operations are complex and fluctuate based on a variety of factors unrelated to the ULSD Project. Equipment may reach the end of its useful life and need replacement. Additional federal, state, or local regulations may impose additional pollution control or other requirements on refineries requiring new equipment to be installed or existing equipment to be modified or replaced. These factors could add new demands on steam generation unrelated to the ULSD Project, making it inappropriate to attribute later changes in steam production to the ULSD Project. Finally, five years is a reasonable period for the mitigation measure to last because refineries typically perform major turn-arounds every five years to maintain equipment and make other modifications required by new regulatory requirements.

The second reason the comment asserts that the mitigation measure will not assure there is no increase in steam demand is that it is based on fuel use for steam production at the entire Wilmington Plant, rather than ULSD Project steam production. As noted in Response 1-78, because of the complex and integrated nature of the steam production process, steam production was calculated per barrel of Refinery throughput during the pre-project and post-project periods. Since the impact in the 2014 Draft EIR was reported by fuel use (which can be converted to emissions), it is reasonable that the metric in the mitigation measure also be fuel use. Since the pre-project fuel use is known for the steam production equipment, any increases above the pre-project level, regardless of the cause, would have to be evaluated by the Refinery operators and reported and explained to the South Coast AQMD as required by mitigation measure AQ-1.

Finally, the comment asserts that the mitigation measure will not assure there is no increase in steam demand because it does not report emissions, the metric of interest. It is legitimate to use fuel use as a surrogate or indirect measure of emissions. Fuel use can be converted to emissions, so if there is an increase in fuel use, this would indicate an increase in emission, which can be calculated. As noted above, any increase in steam production measured by fuel use would have to be evaluated by the Refinery operators and reported and explained to the South Coast AQMD. If there is a per barrel increase in steam use related to the ULSD Project, then the emissions associated with the increase in steam use will be calculated based on the increased fuel use. Therefore, mitigation measure AQ-1 provides certainty that steam generation will not increase as a result of the ULSD Project. Five years is a reasonable duration of the mitigation measure as, after that time, other factors will likely provide greater influence on steam generation than the ULSD Project.

The South Coast AQMD has since received the report on the annual fuel consumption pursuant to the requirement of Mitigation Measure AQ-1. The report is provided in Attachment 4.

<u>Response 1-82</u>

This comment summarizes earlier comments made in this attachment. With regard to pre-project emissions, refer to Responses: 1-3, 1-7, 1-9, 1-10, 1-47, 1-50, 1-53, 1-69, and 1-73. With regard to post project emissions, refer to Responses: 1-9, 1-53, 1-54, 1-62, 1-74, and 1-76. With regard to flaring, refer to Responses 1-59 and 1-60. The comment asserts that NOx emissions from the ULSD Project would be significant and cites comments in Sections II through IV of the attachment. Responses 1-40 through 1-81 respond to all comments contained in II through IV of the attachment.

Attachment B – EPA, Emissions Estimation Protocol for Petroleum Refineries (2014)

Attachment B contains a copy of the U.S. EPA's 2014 Emissions Estimation Protocol for Petroleum Refineries. As discussed in Response 1-60, the update to the Emissions Estimation Protocol for Petroleum Refineries was finalized in April 2015 (Version 3) and is the most recent version of this document. Attachment B is not included as part of the Response to Comments, but is part of the Administrative Record for the project and available on request.

COMMENT LETTER 2

COMMUNITIES FOR A BETTER ENVIRONMENT

November 13, 2014

Mr. Jeff Inabinet
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4182

Via electronic mail: jinabinet@aqmd.gov

Re: Phillips 66 Los Angeles Refinery Ultra Low Sulfur Diesel Project Draft Environmental Impact Report

Dear Mr. Inabinet: 2-1

Communities for a Better Environment ("CBE") submits the following comments on the Phillips 66 Los Angeles Refinery Ultra Low Sulfur Diesel Project ("Project") Draft Environmental Impact Report ("DEIR") issued by the SCAQMD in compliance with the California Supreme Court's order of March 15, 2010. As detailed below, the DEIR suffers from several flaws, and we thereby request that SCAQMD address them and circulate a revised DEIR.

CBE is a California nonprofit environmental health and justice organization with offices in Oakland and Huntington Park. CBE has thousands of members throughout the state of California. More than 2,700 of CBE's members live, work, or engage with environmental justice issues in urban communities in Northern and Southern California. This includes hundreds of people living, working, and breathing in Wilmington and the area surrounding the Phillips 66 Company, formerly ConocoPhillips, Refinery ("Refinery"). CBE's organizational goals include protecting and enhancing the environment and public health by reducing air and water pollution and minimizing hazards in California's urban areas, including the area surrounding the Refinery.

While the DEIR attempts to address the legal deficiencies as ordered by the Court in *Communities For A Better Env't v. S. Coast Air Quality Mgmt. Dist.* (2010) 106 Cal.Rptr.3d 502 by revising the baseline and recalculating the Project's significant air quality effects, there remain significant deficiencies that render the DEIR defective. As the District is well-aware, the underlying Negative Declaration contained an improperly inflated baseline based on maximum permit limits, rather than actual pre-project conditions. That method was flatly rejected the Supreme Court. The instant DEIR uses a different method, but it, too, improperly inflates the baseline by using maximum pre-project emissions, which are not representative of required actual

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conditions. This initial misstep in determining significant air quality impacts is further compounded by comparing the inflated baseline to a low-production post-project time period, which also uses erroneous metrics. Accordingly, the DEIR fails to meet the California Environmental Quality Act's ("CEQA's") requirements.

We have reviewed the Technical Report authored by Dr. Phyllis Fox, commissioned by Safe Fuel and Energy Resources California ("SAFER California") ("Fox Report"), which outlines substantial flaws that are violative of the CEQA.[1] We hereby adopt and incorporate Dr. Fox's November 13, 2014 technical report in its entirety herein. Further, as discussed below, the DEIR is unclear, incomplete, and inadequate, and therefore fails to meet the CEQA's requirements. *See* Pub. Res. Code § 21000, *et seq.*

I. THE DEIR'S BASELINE IS LEGALLY DEFICIENT AND DOES NOT PROVIDE THE NECESSARY UNDERLYING DATA UPON WHICH A SIGNIFICANT ENVIRONMENTAL IMPACTS ANALYSIS MUST BE GROUNDED.

The DEIR employs a misleading and wholly inaccurate baseline to measure air quality impacts. Consequently, the DEIR can provide no real guarantee against the very real, likely and significant air emissions from this Project. Baseline determination is critical to the effectiveness of environmental review, because the baseline environmental conditions are those against which the proposed project's impacts are measured. An inaccurate baseline can drastically alter the outcome of environmental review — if baseline emissions are set too low, insignificant impacts become significant, and if baseline emissions are set too high, an EIR can overlook significant impacts on the environment. The defect here is that the pre-project emissions are unjustifiably elevated, thereby invalidating the DEIR's baseline.

Dr. Fox's report identifies considerable deficiencies and inaccuracies in the baseline determination. As Dr. Fox explains, the District calculated pre-project emissions using maximum daily emissions in 2002-03, rather than average daily emissions. This approach is fatally flawed because the pre-project emissions in the DEIR should be based on a *representative*, average period, rather than an inflated maximum period (which makes any increase in emissions due to the Project appear small by comparison).

CEQA "directs . . . lead agenc[ies to] 'normally' use a measure of physical conditions 'at the time the notice of preparation [of an EIR] is published, or if no notice of preparation is published, at the time environmental analysis is commenced.'" *Communities For A Better Env't*, 48 Cal.4th at 327 (citing Guidelines section 15125) (second alteration in original). However, because "'[e]nvironmental conditions may vary from year to year[,] . . . in some cases it is necessary to consider conditions over a range of time periods.'" *Id.* at 327-28 (quoting *Save Our Peninsula Committee v. Monterey County Bd. of Supervisors* (2001) 87 Cal.App.4th at 125). When baseline emissions are calculated based on a range of time periods, as the District did here, that time period must generally be representative of average conditions, unless the agency can support the use of a different calculation with substantial evidence.

[1] *See* Dr. Phyllis Fox Technical Report prepared for SAFER, November 13, 2014, attached as Exhibit.

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In *Communities For a Better Env't*, the District argued against using "annual averages . . . to arrive at a baseline of daily emissions," because that calculation purportedly "fails to account for . . . the significance of peak production periods." 48 Cal. 4th at 327. The Court responded by explaining that, while "[i]n *some* circumstances, peak impacts . . . *may* be as important environmentally as average conditions[,]" an agency's discretionary decision as to how to measure "existing [pre-project] physical conditions" must be supported by "substantial evidence." *Id.* at 328 (emphasis added). "If an EIR presents alternative methodologies for determining a baseline condition, . . . CEQA requires that each alternative be supported by reasoned analysis and evidence in the record so that the decision of the agency is an informed one." *Save our Peninsula Comm.* 87 Cal.App.4th at 120.

Here, the DEIR failed to use annual averages to establish the pre-project baseline, and instead used "peak" emissions during 2002-03 for at least some Project components. As Dr. Fox points out in her technical report, such is the case for the heater B-201. *See* Fox Report at 6 (citing DEIR at B-3). The District failed to provide the necessary "reasoned analysis," however, as to why peak emissions provide a more accurate measurement for the heater B-201's pre-project existing physical conditions. Neither is there any evidence in the record, much less substantial evidence, to account for peak emissions use. Consequently, decision-makers and the public cannot determine whether peak production here is "as important environmentally as average conditions[.]" *Communities For A Better Env't*, 48 Cal. 4th at 328. Accordingly, the DEIR both artificially inflates the baseline and fails as an informational document.

The baseline is flawed and unreliable based on the additional reason that the DEIR failed completely to identify the baseline years for key Project equipment except for the heater, hydrogen and steam production, resulting in an incomplete DEIR. *See* Fox Report at 5 & 17. Moreover, where the base years (2002-03) *are* known for Project components, the District failed to provide any data that supports its selection of 2002-03 as representative of average emissions, calling the accuracy of the baseline into further question. *Id.*

Further, the DEIR's summary emissions reported for CO, NOx, VOC, SOx, and PM10 for the period of 2000 through 2013 are inapposite for baseline determination. That data, listed in Table 3.1-3, is based on *refinery-wide* emissions. DEIR, Table 3.1-3. According to Dr. Fox's technical evaluation, however, this data cannot support applying a 2002-03 time period "as valid baseline years for individual process units because the modified units/operations emit only a tiny fraction of the total Refinery emissions." Fox Report at 6. Using refinery-wide emissions data "mask[s] changes in emissions from much smaller units[,]" thus rendering the table inapplicable and insignificant as baseline support. *See id.* Accordingly, the DEIR should have provided more specific baseline information about the particular processes in the refinery which are key in determining the Project baseline, such as the variation in hydrogen needed in the refinery to produce diesel.

The baseline for the entire refinery cannot be the same as the baseline for diesel production, because refineries can and do change the proportion of different products they make according to the market price of individual products. So while the DEIR used a generally low period for overall refinery post-project emissions (when all production *including* diesel was depressed), it should have provided more specific baseline data on the *maximum potential to emit for diesel production*

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that the Project allows, including key data such as hydrogen demand used in this production. *See* Fox Report at 6-9.

Based on the foregoing, the DEIR's baseline is fatally flawed, the DEIR cannot be used to accurately determine the Project's significant impacts.

II. THE DEIR'S POST-PROJECT'S EMISSIONS ARE LEGALLY DEFICIENT AND DO NOT ADEQUATELY ANALYZE SIGNIFICANT ENVIRONMENTAL IMPACTS.

The DEIR's post-project emissions determinations are similarly inherently flawed and cannot be used to calculate accurate significant air quality effects.

One of the significant errors found by Dr. Fox in the District's determination of post-project emissions is its measurement of *annual average* emissions from 2006 though 2008, rather measuring the "*maximum potential* to emit." *See* Fox Report at 8. The maximum potential to emit is determined from either permit levels or a unit's engineering evaluation based on physical design. The maximum potential emissions metric is necessary because current emissions do not reflect the full capacity of the new equipment to operate, and Phillips can therefore increase production at will up to the physical constraints of the equipment, causing increased emissions. Not only does basic logic mandate the use of maximum potential emission to determine true Project impacts, but the 1993 SCAQMD CEQA Handbook requires use of that metric. It provides that, "[i]n determining whether or not a project exceeds these thresholds, the project emissions should be calculated . . . utilizing the highest daily emissions." 1993 SCAQMD CEQA Handbook at 6-3. The District failed to apply this standard. For instance, as Dr. Fox explains, the District estimated the increase in emissions resulting from increased hydrogen production based on *average annual emissions*, which, again, is an erroneous measure for post-project emissions. *See* Fox Report at 6-8.

Further, where the District did estimate post-project emissions based on permit limits, those limits are not substantiated by the record. *See* Fox Report at 13-15. Dr. Fox explains that her examination of a Title V Permit for the Wilmington Refinery did not corroborate the DEIR's stated emission limits. *See id.* at 13. The use of those limits must therefore be revised.

Another of the numerous deficiencies identified by Dr. Fox concerns the DEIR's use of the 2006-08 period to determine the post-project emissions. *See* Fox Report at 7. Dr. Fox points out that the District failed to state a basis for selecting 2006-08 as an appropriate time period. *Id.* Using emissions data for 2007 to make a post-project determination results in a drastic underestimation of Project emissions because demand for fuel was depressed during that year. *Id.* Specifically, the DEIR uses recession year data for hydrogen production emissions. *Id.* The time period for post-project emission determinations must also be revised.

Accordingly, the DEIR's post-project emissions are erroneous and cannot accurately determine the Project's significant effects.

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III. THE DEIR DOES NOT ADEQUATELY ANALYZE SIGNIFICANT ENVIRONMENTAL IMPACTS, AND THUS FAILS TO INCLUDE FEASIBLE MITIGATION MEASURES TO ADDRESS THESE IMPACTS.

The DEIR improperly calculated the Project's air quality impacts and therefore fails to meet the CEQA's requirements. The CEQA requires project proponents to address all of a proposed project's anticipated environmental impacts. Public Resource Code § 21100(b)(1); *see also, County of Inyo v. City of Los Angeles* (1977) 71 Cal.App. 3d 185, 199. CEQA Guidelines require that "[a]n EIR shall identify and focus on the significant environmental effects of the proposed project." In addition, agencies should not approve projects if there are feasible mitigation measures or project alternatives available to reduce or avoid the significant environmental impacts contained in the project's EIR. Public Res. Code §§ 21002, 21002.1(a).

Because, as already discussed, the DEIR improperly calculated both pre-Project baseline and post-Project emissions, the increase in emissions and resultant air quality impacts are greatly underestimated.[2] When these deficiencies (and other calculation deficiencies described below) are corrected, Project emissions are significant and must be mitigated.

Further, the District underestimates the significant impacts of the Project by failing to use the most recent significance criteria or the most accurate emissions factors for calculating emissions. As a result, though this DEIR focuses on potential NOx emissions from the Project (DEIR at 1-6), the District nevertheless significantly underestimates NOx emissions, and thereby fails to include the increased NOx emissions as significant impacts. When the DEIR's errors are corrected, emissions are shown to have a significant effect on air quality, and therefore need to be mitigated. For example, Nitrogen Oxide emissions (NOx) are at least 80 lbs/day. *See* Fox Report at 22. The District does not and cannot propose feasible mitigation measures or project alternatives to avoid these impacts. The DEIR thus fails to comply with the requirements of the CEQA that the EIR identify significant environmental impacts and mitigation measures or alternatives to reduce or avoid these impacts.

A. The DEIR Does Not Adequately Analyze Significant Environmental Impacts

The DEIR fails to adequately analyze significant impacts because it relies on out-of-date significance criteria and failed to include emissions from several sources. First, the DEIR relies on regional significance criteria for PM2.5 from 1993. Fox Report at 3-4; DEIR at 3-32 (Table 3.3-6). In 2006, however, the District revised the significance thresholds to include localized significance thresholds (LSTs) for PM2.5.[3] The LSTs are significantly lower than the threshold relied upon in

[2]

Pre-Project emissions were overestimated	Post-Project emissions were underestimated
Calculated using the maximum daily emissions in 2002-03 rather than average daily emissions.	Calculated using annual average emissions during 2006-08, rather than highest daily emissions, based on permit limits or equipment physical constraints.

[3] The LSTs can be found at: http://www.aqmd.gov/docs/default-source/ceqa/handbook/localized-significance-

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the DEIR, yet the District fails to include an analysis of whether the PM2.5 emissions will exceed the LSTs.

The DEIR notes that there are regional significance criteria for lead emissions (3 lbs/day), yet ignores potential sources of lead emissions. DEIR at 3-32 (Table 3.3-6). These sources include the heater, hydrogen production, electricity demand, and truck transport, all of which can emit lead. Fox Report at 4. Lead emissions are by their nature very important to evaluate, as lead is persistent in the environment and accumulates, and can cause severe developmental and other impacts to children and adults at low levels. What is more, in order for the DEIR to serve its purpose of informed decisionmaking and public participation, the DEIR must analyze these emissions. *See Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1355 ("the failure to include relevant information precludes informed decisionmaking and informed public participation, thereby thwarting the statutory goals of the EIR process").

The failure to include the lead emissions from these sources highlights a problem throughout the DEIR – its failure to calculate emissions from hydrogen production, energy production, flares, and other sources. This failure (along with other errors, such as flaws in the emissions factors chosen, *see* Fox Report at 8-9, 11, means that the DEIR significantly underestimates the emissions and significant impacts of NOx.

For example, hydrogen production requires support of many different refinery processes, so increased hydrogen production causes emissions increases in other refinery equipment that were not calculated, including emissions from flaring and indirect sources. *Id.* at 6-11. Indeed, flare source emissions, which are required to produce hydrogen, are missing from the emissions calculations. These emissions by themselves are major when using updated emissions factors provided by EPA, resulting in NOx emissions of over 100,000 lbs/day, grossly exceeding the 55 lb/day CEQA threshold of significance. *Id.* at 9 &11.

Startup and shutdown NOx emissions of new heater B-401 are also omitted and must be included. During these periods, heater operation would not include SCR controls, which reduce emissions by 90%. These emissions could result in an increase in NOx emissions of about 20 lbs/day, not prohibited by permit limit. When combined with other NOx emissions that were improperly left out of the DEIR, NOx emissions would be significant – 80 lbs/day – even without large NOx emissions from flaring that were also left out. *Id.* at 14.

In addition, the DEIR aggregated data from two units (89 – jet hydrotreater, and 90 – diesel hydrotreater), which can mask increased use of hydrogen in Project Unit 90, with associated increased emissions. *Id.* at 7. While the DEIR states that these are not separately reported, the refinery could nevertheless provide related data to disaggregate the impacts of these two units, as the refinery certainly has some separate data on the volumes and qualities of production of jet and diesel.

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thresholds/particulate-matter-(pm)-2.5-significance-thresholds-and-calculation-methodology/final_pm2_5methodology.pdf?sfvrsn=2, Appendix B.

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While these are a few examples of the DEIR's omissions of critical information, the technical report by Dr. Fox, incorporated here by reference as noted above, provide further details on the DEIR's underestimation of emissions or complete failure to estimate emissions for a number of chemicals (carbon monoxide and others) and emissions sources, including indirect emissions sources caused by increased electricity demand, and other indirect sources identified in the Fox Report

B. The DEIR Did Not Analyze Mitigation Measures or Alternatives to Avoid or Reduce Significant Impacts

As a result of these errors and omissions, the DEIR significantly underestimates NOx emissions. *See* Fox Report at 19. An EIR must "identify the significant effects on the environment of a project, . . . alternatives to the project, and . . . indicate the manner in which those significant effects can be mitigated or avoided." Pub. Res. Code at § 21002.1(a); *see also id.* at §§ 21002, 21002.1(b) (agency must implement all feasible measures to mitigate or avoid significant impacts). Here, because the DEIR misses the significant emissions of NOx, it does not and cannot identify feasible mitigation measures or alternatives to reduce these emissions and alleviate impacts caused by these emissions, as required by CEQA.

Beyond the potential localized impacts of PM2.5 and other pollutants that the DEIR improperly ignores, in the South Coast, minimizing NOx emissions is critical. The area is out of attainment for ozone and PM2.5. DEIR at 1-12. (In fact, the region missed the deadline to meet the 1-hour ozone standard in November 2010, despite having over two decades to attain the standard. 76 Fed. Reg. 82133 (December 30, 2011)). NOx is a precursor of both ozone and PM2.5. Reducing NOx emissions is critical to attaining those standards. In fact, the California Air Resources Board estimates that to meet the 0.08ppm 8-hour federal ozone standard by 2023, the region will need to reduce its NOx emissions by 80% from 2010 levels, and to meet the 0.075ppm 8-hour ozone standard by 2032, the region will need to reduce its NOx emissions by 90% from 2010 levels. California Air Resources Board, *Vision for Clean Air: A Framework for Air Quality and Climate Planning* (Public Review Draft, June 27, 2012) at 10.[4] It is thus critical that the DEIR correctly analyze and mitigate NOx emissions from this project in order to ensure that it does not interfere with attainment of federal standards.

IV. FAILURE TO DISCLOSE CRUDE-QUALITY IMPACTS IN PROJECT DESCRIPTION AND SIGNIFICANT IMPACTS ANALYSIS.

As described throughout this comment, the incorrect calculation methods used to determine pre- and post-project emissions have resulted in significantly underestimated project emissions, and the omission of any information disclosing the Refinery's change in crude slate falls among these errors. Nothing in the EIR discusses reasonably foreseeable, significant changes in the Refinery's crude feedstock, which will shift the quality of the crude slate currently processed at the Wilmington Refinery to an overall denser and higher sulfur-content slate.

The specific chemicals present in the type of crude processed at the Refinery directly

[4] Available at: http://www.arb.ca.gov/planning/vision/vision.htm.

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impact the emissions released during processing. According to Phillips 66 corporate statements, the company is executing plans to move "cut-price Canadian crude to its California refineries via rail, and ship."[5] This "cut price," otherwise known as "cost advantaged crude" includes diluted tars bitumen, a type of crude that is notoriously high in sulfur content, dense, and which requires high amounts of electricity and heat to refine. These characteristics implicate significant air quality impacts, including increased air emissions, as well as increased risks of hazards. Disclosure and analysis of the specific chemical composition of the baseline and projected future crude slates processed at the Refinery are, therefore, essential to determining environmental and particularly air quality impacts, as any increases in emissions may become significant when measured in relation to existing impacts from processing the Refinery's current crude slate.

These and additional concerns were raised by CBE in its October 9, 2013 Comment Letter Opposing SCAQMD's Notice of Intent to Adopt a Proposed Negative Declaration (ND) for the Phillips 66 Crude Oil Storage Capacity Project at its Carson facility ("CBE's Carson Storage Capacity Project ND Comments").[6] Those comments addressed, *inter alia*, Phillips 66's failure to disclose its corporate plans, described above, and the initial study's failure to analyze the full range of potential impacts resulting from key de-bottlenecking and control process changes, which enable the refinery to process heavy, tar sands bitumen, and Bakken crudes.

The points of opposition raised by CBE in response to the proposed ND for the Crude Oil Storage Capacity Project are relevant to the District's analysis of the DEIR under review here for two primary reasons. First, because the Carson and Wilmington facilities are connected via a shared pipeline and together form what is known as the Phillips 66 Los Angeles Refinery, operations, process changes and resulting impacts at one facility may implicate the same at the other facility. As explained in further detail in CBE's Carson Storage Capacity Project ND Comments, the project description for that project assumes a consistent, continued exchange of petroleum products between the Carson and Wilmington facilities by existing pipelines between the two facilities; by marine terminals and pipeline on the Carson end; and by rail and additional pipeline on the Wilmington end.[7] The inherent process and operational connections between the two facilities require that potential impacts from projects at one facility be fully identified and analyzed in relation to the other. To the extent Philips 66 explicitly states its intent to bring down the "cost-cut," "advantaged," or "cost advantaged" crudes by both rail and ship, the impacts of doing so must be identified and analyzed for potential impacts at both the Carson and Wilmington facilities.

Second, the ULSD project's incorporation of some of the same project components identified in the Crude Oil Storage Capacity Project ND and CBE's Comments as essential to processing denser, higher sulfur content crudes, suggests that critical impacts left undisclosed in the ND analysis for that project, are likewise left without analysis in the DEIR for the ULSD

[5] *Phillips 66 moving some Canadian crude to Calif. refineries –exec*, Feb 5, 2013, updated May 2013, last accessed November 12, 2014, available at: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx

[6] CBE's Comments Opposing SCAQMDs Adoption of the Phillips 66 Carson Plant – Crude Oil Storage Capacity Project ND, October 9, 2013, at 14 (citing ND at 2-48); Report of Julia E. May, CBE, on Phillips 66 LA Refinery Carson Plant Crude Oil Storage Capacity Project Draft ND, Comments to SCAQMD, October 9, 2013.

[7] *Id.*

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project. The Crude Oil Storage Capacity Project involves, for example, modifications to incoming feeds to the Carson Crude Unit, including temperature modifications that are necessary to process Western Canadian tar sands and Bakken crude oils, as documented in CBE's Carson Storage Capacity Project ND Comments.[8] These modifications would debottleneck the Los Angeles refinery allowing it to process these cost-"advantaged" crude oils. Yet, while they are referenced in the DEIR under review here, they are not analyzed, or mitigated.

The DEIR refers to temperature monitoring and control valve modifications at the Carson Crude Unit generally, by describing the incorporation of temperature changes at the DU-5 Crude Unit at the Carson Plant into ULSD project operations as follows:

> "The Project scope included temperature monitoring equipment and modifications to flow control valves in order to improve crude distillation operations and minimize the high sulfur portion of the distilled crude routed to Unit 90. Maintenance workers performed the minor modifications (add premanufactured thermocouples and modify existing control valves) that were required to the unit. These changes did not result in physical impacts to the environment (air emissions, noise, traffic, etc.) so the environmental evaluation in this EIR is limited to the project activities at the Wilmington Plant (CEQA Guidelines §15064(d)(1))."

DEIR at 1-10. The DEIR does not, however, proceed to analyze these temperature changes, for any potentially significant impacts, nor does it fully describe the purpose of such changes in relation to overall refinery operations.

Because the District is in possession of CBE's Comments Opposing the ND for the Crude Oil Storage Modification Project and its attachments, CBE, hereby incorporates by reference, the full record for that project, including the proposed ND, any comments received, and the application submitted to SCAQMD as relevant points of analysis regarding any and all temperature process changes involved in the ULSD, and the Crude Oil Storage Capacity Modification projects. Additional process changes and modifications identified in CBE's Comment letter opposing the ND, and include but are not limited to, any storage tank modifications involved in both projects and the potential use of such storage changes to facilitate shifts in crude oil feedstock for the Los Angeles Refinery overall, including both the Carson and Wilmington facilities.

In sum, the potential for the new ULSD DEIR to mask incorporation of aspects of the Crude Oil Storage Modification Project must be explicitly evaluated in the DEIR for the ULSD. This is necessary in order to avoid piece-mealing and/or an incomplete project description, and to evaluate the major environmental impacts associated with foreseeable changes in feedstock source, and quality.

Finally, changes in the overall quality and chemical composition of the crude slate currently processed at the Wilmington refinery also carries the risk of significant increases in the cumulative burden of air emissions and other existing environmental impacts in the area. By failing to address

[8] Report of Julia E. May, CBE, on Phillips 66 LA Refinery Carson Plant Crude Oil Storage Capacity Project Draft ND, Comments to SCAQMD, October 9, 2013.

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issues relating to these changes, the DEIR falls far short of meeting its obligation to identify, analyze, and mitigate where necessary, the direct, indirect and cumulative impacts of the project based on an accurate baseline and reasonable forecasts of future impacts of the Project. *See Laurel Heights Improvement Ass'n v. Regents of University of California* (1993) 6 Cal.4th 1112, 1123; Pub. Res. Code § 21002 (public agencies should not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects); Guidelines § 15126.4. For these, and the additional reasons expressed in this Comment, the DEIR fails to meet CEQA requirements, and fails as an informational document. *Santiago County Water District v. County of Orange* (1981) 118 Cal. App. 818, 831 (An EIR must provide sufficient information "how adverse" potential environmental impacts will be.).

V. THE DEIR IMPROPERLY CONCLUDES THAT THE PROJECT RESULTS IN NO SIGNIFICANT IMPACTS BASED SOLELY ON LOCAL SIGNIFICANCE THRESHOLDS, DESPITE EXISTING ARGUMENTS TO THE CONTRARY.

The District determined "whether or not air quality impacts from the ULSD Project are significant . . . [by] evaluat[ing] and compar[ing] [the impacts] to the" District's project-specific significant thresholds. DEIR at 3-31. The DEIR considers Project impacts significant only if the "impacts equal or exceed any of the [threshold] criteria[.]" *Id.* The District compared the net increase emissions (which are flawed, as discussed above), and compared them to the District's project specific significant thresholds. In each case, the emissions show to be significantly lower than the thresholds. The District proceeds to conclude that, because the emissions "do[] not exceed any significant thresholds[,]" "the air quality impacts associated with the operational emissions from the ULSD Project are less than significant." *Id.* at 3-40. As the courts have held, however, "the fact that a particular environmental effect meets a particular threshold cannot be used as an automatic determinant that the effect is or is not significant." *Protect The Historic Amador Waterways v. Amador Water Agency*, 116 Cal. App. 4th 1099, 1109, as modified (Apr. 9, 2004) (citing *Communities for a Better Environment v. California Resources Agenc*y (2002) 103 Cal.App.4th 98, 107).

"[T]hresholds of significance can be used only as a measure of whether a certain environmental effect 'will normally be determined to be significant' or 'normally will be determined to be less than significant' by the agency. *Id.* at 1098 (citing Guidelines, § 15064.7(a)). "In each instance, notwithstanding compliance with a pertinent threshold of significance, the agency must still consider any fair argument that a certain environmental effect may be significant." *Id.* Accordingly, a threshold of significance cannot be applied in a way that would foreclose the consideration of other substantial evidence tending to show the environmental effect to which the threshold relates might be significant." *Id.* at 1099. The District, here, however, did just that.

For all of the reasons discussed above, the District cannot simply stop at comparing the increased emissions against significance thresholds, but must rather consider all of the factors, as detailed throughout these comments and Dr. Fox's report, to determine the Project's air quality impacts.

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VI. THE DEIR DOES NOT IDENTIFY A CLEAR BASELINE AND THEREFORE FAILS AS AN INFORMATIONAL DOCUMENT.

The key inquiry in determining the adequacy of a baseline is whether the baseline "inform[s] decision makers and the public of the project's significant environmental impacts, as CEQA mandates." Pub. Res. Code §21100. Ultimately, the lack of sufficient information in several areas and the lack of crucial technical evidence make the DEIR unclear and far from a single report clearly written to inform the reader of the consequences of the Project. Without this information, the public cannot understand and participate in the decision-making process, and the District cannot fulfill its CEQA obligations. *See Laurel Heights Improvement Ass'n. v. Regents of University of California* (1988) 47 Cal.3d 376, 392.

The DEIR includes a table summarizing the *net operational* emissions emitted by the ULSD Project. *See* Table 3.3-7. Because the net emissions of the Project are the resulting difference between pre-project (baseline) and post-project (operational) emissions, the public can make sense of the net emissions only by knowing the former. However, there is nothing in the Environmental Settings, Impact, and Mitigation section of the DEIR that describe the baseline or post-project emissions.

The District calculated the baseline using pre-project emissions from the 2002-03 time period for refinery operations, which assertedly "represents the timeframe during the environmental analysis development for the ULSD Project prior to the construction and operation of the ULSD Project." DEIR at 1-10 & 3-33. The DEIR contains two tables purporting to show the 2002-03 baseline emissions, but neither actually identifies those emissions. Table 3.1-3 reports only tons per year of criteria pollutant emissions for the period of 2000 through 2013, rather than identifying average daily emissions. Further, although the DEIR states that "[d]etailed baseline and post-project information on each component of the ULSD Project is described[,]" that information does not actually follow. *See* 3-33–37. For example, the discussion in the DEIR concerning hydrogen production states that "[t]he baseline hydrogen demand in Units 89 and 90 were based on monitoring data of hydrogen use in 2002-2003 for the two units combined[,]" and proceeds to discuss only net emissions increases. *See id.* at 3-35. There is no information indicating what the baseline and post-project emissions are. *See id.* Without providing a clear comparison between pre-project "existing physical conditions" and post-project conditions, the DEIR violates Section 21100's requirement that the District adequately inform the public of the Project's significant environmental impacts. *See* Pub. Res. Code § 21100.

The purported pre- and post-project emissions are identified only in Appendix B of the DEIR. It is well-established, however, that readers of any EIR should not be forced to sift through obscure minutiae or appendices, or to rely on outside research and resources to find important components of a thorough environmental analysis. *San Joaquin Raptor Rescue Ctr. v. County of Merced* (2007) 149 Cal.App.4th 645, 649; *see also*, *California Oak Found. v. City of Santa Clarita* (2005) 133 Cal.App.4th 1219, 1239. Accordingly, the DEIR undermines CEQA's purpose of ensuring the public's understanding and participate in these decision-making processes, and fails to serve as an informational document.

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VII. THE DEIR FAILS TO ADEQUATELY ANALYZE SIGNIFICANT CUMULATIVE IMPACTS.

The DEIR contains a flawed analysis of cumulative impacts of the Project, one of CEQA's most vital requirements. *See* Pub. Res. Code § 21082 (referring to the CEQA Guidelines §§ 15130(a)(1) and 15355 for the applicable definition of cumulative impacts); *see also*, *Bozung v. Local Agency Formation Commission* (1975) 13 Cal.3d 263, 283 (holding that the cumulative impacts analysis of a project's regional impacts is a "vital provision" of CEQA).

A project has a significant cumulative effect if it has an impact that is individually limited but "cumulatively considerable." CEQA Guidelines §§ 15065(a)(3), 15130(a). "Cumulatively considerable" is defined as meaning that "the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." *Id.* at § 15065(a)(3).Cumulative impacts analysis is necessary because "environmental damage often occurs incrementally from a variety of small sources [that] appear insignificant when considered individually, but assume threatening dimensions when considered collectively with other sources with which they interact." *Communities for a Better Env't v. Cal. Res. Agency* (2002) 103 Cal.App.4th 98, 114. The DEIR fails to meet this requirement because its analysis of cumulative impacts is incomplete and ignores the applicable legal standard.

The DEIR admits that "[t]he past, present, and reasonably foreseeable future projects *would have a significant cumulative impact*." DEIR at 4-9 (emphasis added). The DEIR then concludes, however, that the "project-specific air quality impacts associated with . . . [the Poject] are not considered to be . . . cumulatively considerable[.]" *Id.* The District justifies its conclusion on the grounds that "[t]he contribution of the project to cumulative air quality is very small[,]" and because the Project's emissions purportedly fall below the District's project-specific significant thresholds. *Id.* The District's conclusion, however, turns the applicable legal standard on its head and is simply indefensible.

An EIR must "discuss cumulative impacts of a project when the project's incremental effect is *cumulatively* considerable." CEQA Guidelines § 15130(a) (emphasis added). Indeed, District must find "that [the] project may have a significant effect on the environment" if it "has possible environmental effects that are individually limited but cumulatively considerable." CEQA Guidelines § 15065(a). Here, the District found that, while limited on its own, the effects of the Project are in fact cumulatively significant, but nevertheless, and contrary to the mandate of § 15065(a), concluded that the impacts are not cumulatively significant. The District's legal reasoning would altogether discard with the requirement that an agency undertake a cumulative impacts analysis whenever it deems that a project's individual effects fall below significant thresholds or make up a "small portion" of cumulative effects. Such a proposition simply cannot stand, however, since it conflicts with the plain language of CEQA and its implementing Guidelines. The District's position is therefore untenable.

Cumulative effects "considerable" when "incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." Pub. Res. Code § 21083(b)(2). Applying this

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standard, the inescapable conclusion, as acknowledged by the DEIR, is that the incremental effects of the Project together with the past, present, and reasonably foreseeable future projects *do* have a significant cumulative effect. *See* DEIR at 4-9. The District's cumulative impacts analysis in the DEIR is therefore entirely deficient.

What is more, the DEIR fails to adequately analyze the existing cumulative impact burden of the larger geographical area. As a result, it fails to analyze and, where necessary, mitigate the full range of the Project's potential impacts in light of this burden. The Wilmington-Carson area houses five refineries, which comprises the highest concentration of refineries in California. Additionally, all of the areas surrounding the Wilmington-Carson refineries rank in the top 20% (with several areas in the top 5%) most overburdened and vulnerable areas in the State according to the most recent version of the California Environmental Protection Agency's CalEnviroScreen, version 2.0.

VIII. CONCLUSION

For the reasons stated herein, and in the additional technical reports submitted in response to the DEIR, as well as other comments incorporated by reference in this document, the DEIR fails to adequately identify, analyze and mitigate where necessary the significant impacts from this project, and therefore fails to comply with CEQA. As such, the DEIR must be revised to address its flawed analyses and re-circulated for public comment.

Sincerely,

/s/

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COMMENTS

on

Draft Environmental Impact Report

for the

Phillips 66

Ultra Low Sulfur Diesel Project

Prepared

For

SAFER

November 13, 2014

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I. INTRODUCTION

I have reviewed the Draft Environmental Impact Report (DEIR) for the Ultra Low Sulfur Diesel Project (Project or ULSD Project) at the Phillips 66 Los Angeles Refinery (Refinery).[1] This DEIR was prepared in response to a decision of the California Supreme Court[2] that found deficiencies in previously prepared CEQA documents.

My review of this DEIR indicates that it fails to cure the deficiencies found by the California Supreme Court and raises new issues. The revised DEIR fails to adequately support its emission calculations, excluding key data, assumptions, and calculations used to estimate Project emission increases. Thus, it fails as an informational document under CEQA.

Further, this DEIR improperly calculates both pre-project and post-project emissions. Pre-project emissions were calculated using the maximum daily emissions in 2002-2003 rather than average daily emissions. Post-project emissions were calculated using annual average emissions during 2006-2008, rather than "highest daily emissions", based on permit limits or physical constraints of the subject equipment.

Finally, the DEIR improperly modified certain key emission factors, without disclosing the changes. It further used superceded emission factors that significantly underestimate emissions.

These various flaws significantly understated NOx emissions. The increase in NOx emissions exceeds 80 lbs/day when these defects are cured. This exceeds the CEQA significance threshold of 55 lb/day. Thus, the increase in NOx emissions is a significant unmitigated air quality impact that was not disclosed in the DEIR.

My resume is attached as **Exhibit 1** to these comments. I have over 40 years of experience in the field of environmental engineering. I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley. I am a licensed professional engineer (chemical, environmental) in five states, including California; a Board Certified Environmental Engineer, certified in Air Pollution Control by the American Academy of Environmental Engineers; and a Qualified Environmental Professional, certified by the Institute of Professional Environmental Practice.

I have prepared comments, responses to comments and sections of EIRs for both proponents and opponents of projects on air quality, water supply, water quality, hazardous waste, public health, risk assessment, worker health and safety, odor, risk of upset, noise, land use and other areas for well over 100 CEQA documents, including for all California refineries.

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[1] Environmental Audit, Inc., Phillips 66 Los Angeles Refinery Ultra Low Sulfur Diesel Project Draft Environmental Impact Report, Prepared for South Coast Air Quality Management District, SCH No. 2004011095, September 2014.
[2] *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310.*

I was a consultant to a former owner of the subject Refinery on CEQA and other environmental issues for over a decade. I also wrote the original comments on this Project in 2004, which led to the CBE v. SCAQMD California Supreme Court decision addressed in this DEIR. Those comments are attached as **Exhibit 2.**

II. EMISSION ESTIMATING FRAMEWORK

The DEIR recalculates the increase in emissions from the Ultra Low Sulfur Diesel Project (Project or ULSD Project) at the Phillips 66 Los Angeles Refinery (Refinery) to address errors in the Project baseline found by the California Supreme Court in CBE v. SCAQMD. The purpose of this DEIR was to cure the original baseline error -- using permitted levels as the pre-project or baseline emissions. The revised DEIR introduces new errors that underestimate the increase in emissions. Further, the revised emissions are inadequately supported. When the errors and omissions described below are corrected, the Project results in significant air quality impacts due to NOx emissions.

The DEIR estimated changes in emissions from: (1) fugitive components; (2) a replacement heater; (3) storage tank 331; (4) hydrogen production; (5) electricity demand; (6) truck transport; and (7) steam demand. DEIR, Table 3.3-7 and Appx. B. The DEIR used different methods to calculate the increase in emissions from each of these sources. Most of the methods used in the DEIR underestimate emission increases and are inconsistent with standard procedures and the selected significance thresholds, which are based on peak day increases.

The increase in emissions due to a project at an existing facility is the difference between post-project (future) and pre-project (baseline) emissions, expressed as:

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

The post-project emissions are the maximum emissions that can be released as a result of the project. These are often called the maximum day or peak day emissions. If project emissions are limited by permit, the permit limits are used as the post-project emissions. In the absence of permit limits, the physical capacity of the subject equipment is used to estimate post-project emissions.

The pre-project or baseline emissions are the actual emissions as they exist at the time environmental analysis is commenced, without the project. They are typically calculated as annual average emissions in the two years preceding the start of environmental review, unless there are unusual circumstances, such as a lull or spike that occurred during that period. In that case, a much longer period of record is examined and presented in the CEQA document to support the selection of a different baseline period or averaging convention, together with a discussion of the alternate choice.

The DEIR asserts that it estimated the increase in emissions from each project component using baseline emissions from 2002-2003 and post-project emissions from April 2006 through December 2008. DEIR, p. 3-33. However, a close examination of the supporting calculations in Appendix B indicates significant variations in this general procedure were followed for the various sources. In some cases, the methods used to estimate pre-project or post-project emissions result in underestimating the Project emission increases, including for: (1) the replacement heater, (2) hydrogen production, and (3) electrical demand. The following methods were used:

Pre-Project

- Fugitives: pre-project component counts
- Heater: maximum day in 2002-2003
- Hydrogen production: 2002-2003
- Electrical demand: not stated
- Steam production: 2002-2003
- Vehicle emissions: not stated
- Tank: 0 as out of service

Post-Project

- Fugitive Emissions: as-built surveys
- Heater: Permit limits or SCAQMD default emission factors
- Hydrogen Production: 2006-2008
- Electricity Demand: new equipment design, no increase from existing sources; no year stated
- Steam production: 2006-2008
- Vehicle Emissions: 2004
- Tank 331: design capacity

The increase in emissions is compared with significance criteria. If the increase in emissions "equals or exceed" any significance criteria, air quality impacts are significant for that pollutant. DEIR, p. 3-31.

The averaging convention used in equation (1) -- daily, quarterly, monthly, or annual – depends on the significance criteria selected to evaluate impacts. The DEIR selected the South Coast Air Quality Management District's (SCAQMD's) significance criteria published in the 1993 SCAQMD CEQA Handbook. DEIR, Table 3.3-6, note (a). These criteria were subsequently updated in 2006, but the DEIR fails to cite the update.[3] This is a significant

[3] SCAQMD, Final – Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Threshold, October 2006, Available at: http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook.

omission, as the PM2.5 significance thresholds in the update are lower than the 55 lb/day threshold used in the DEIR.[4]

The SCAQMD significance criteria are expressed in pounds per day (lb/day) of nitrogen oxides (NOx: 55 lbs/day), volatile organic compounds (VOC: 55 lbs/day), particulate matter with an aerodynamic diameter less than 10 microns (PM10: 150 lbs/day), particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5: 55 lbs/day), carbon monoxide (CO: 550 lbs/day), and lead (Pb: 3 lbs/day). DEIR, Table 3.3-6.

Lead emissions were not calculated in the DEIR, even though the heater, hydrogen production, electricity demand, and truck transport emit lead. Thus, the DEIR is deficient as an informational document.

The SCAQMD CEQA Handbook explains that "[i]n determining whether or not a project exceeds these thresholds, the project emissions should be calculated…using the highest daily emissions."[5] This confirms that post-project emissions should be the highest daily or peak day emissions, not the annual average day based on an annual average in the middle of a recession, as used in the DEIR for hydrogen production.

Thus, if a permit limit or other metric is expressed as an annual average, it would not be sufficient to compare the average daily emissions, estimated by dividing the annual average emissions by 365 days per year, to the SCAQMD daily significance thresholds if operations fluctuate around the daily annual average. Rather, the maximum day emissions must be used to determine if the increase in project emissions is significant. This requires examination of several years of post-project daily emissions to select the maximum, or an engineering evaluation of the equipment to determine peak daily emissions. The DEIR fails as an informational document as none of this information is in the record.

The DEIR did not conduct a peak daily analysis, or provide any of the data required for a reviewer to perform this analysis or check the DEIR's selection. In fact, the DEIR uses different pre-project and post-project periods and averaging conventions for each emission source. These appear to have been selected to underestimate the increase in emissions due to the Project. The various ways in which Project emissions are underestimated are discussed below for three of the emission sources: (1) replacement heater; (2) hydrogen production; and (3) electricity demand.

---

[4] The PM2.5 update includes two PM2.5 significance thresholds, a regional threshold of 55 lb/day, as reported in the DEIR, and localized thresholds, reported in lookup tables as a function of location, receptor distance, and project size. 2006 SCAQMD Handbook Update, Table B-2. The DEIR's analysis ignores the localized thresholds. These thresholds indicate that the Project could result in significant localized PM2.5 impacts. To rebut this presumption, the applicant must conduct a more detailed modeling analysis. 2006 SCAQMD Handbook Update, p. 8.
[5] 1993 SCAQMD CEQA Handbook, p. 6-3.

III. GENERIC ERRORS AND OMISSIONS

A. Emissions From Downstream Supporting Processes Are Omitted

The DEIR estimated changes in emissions from: (1) new fugitive components; (2) a new replacement heater in Unit 90; (3) reactivation of existing storage tank 331; (4) increased hydrogen production; (5) electricity demand to support Unit 90; (6) truck transport; and (7) steam demand for Unit 90. DEIR, Table 3.3-7 and Appx. B. However, in these calculations, the DEIR narrowly focuses only on Unit 90 and new equipment, ignoring increases that occur at existing equipment required to support Unit 90. My previous comments discussed these omissions and are attached in **Exhibit 2.**

The Project would reduce the sulfur content of diesel from about 500 ppmw to 15 ppmw. This would require an increase in utilities to support Unit 90 as well as downstream units that support Unit 90. For example, in Unit 90, sulfur is removed from diesel by converting it to hydrogen sulfide. The hydrogen sulfide is separated from the diesel in a stripper and removed in downstream processing units. The sour gas stream is treated in an amine treatment unit to remove and recover H_2S. The H_2S stream from the amine treatment unit is fed to a sulfur recovery unit to recover elemental sulfur or manufacture sulfuric acid. Sour water is treated in a steam stripper. The removal of increased amounts of sulfur in these units requires additional steam, electricity and heat, which requires the combustion of additional fuel and releases more pollutants. The DEIR excluded these associated utility demands and related emissions from its calculations and all of the information required to independently estimate them. Thus, the DEIR fails as an informational document under CEQA.

B. Pre-Project (Baseline) Emissions

The DEIR selected 2002 to 2003 as the pre-project baseline years for the heater, hydrogen production and steam production, but does not disclose the assumed baseline years for other emission sources. DEIR, Appx. B. Thus, the DEIR is deficient as an information document.

The selection of 2002 to 2003 for the heater, steam production, and hydrogen production is unsupported. Usually, to support any given baseline, data over a much longer period of record is presented to demonstrate that the selected years are representative of actual conditions at the start of the CEQA review. The years 2002 to 2003 are the two years immediately preceding the start of CEQA review and thus are potentially a reasonable choice. However, other circumstances may be present that warrant review of a longer pre-project record. Sometimes, companies temporarily increase operations artificially to establish a higher baseline, which has the effect of reducing emission increases due to the Project. Thus, to support a selected baseline, one generally needs to supply a longer period of record, at least 10 years, to confirm routine actual operations in the baseline years.

The DEIR uses "peak" emissions during 2002 and 2003 to establish the pre-project baseline for heater B-201. DEIR, p. B-3. This is a fundamental flaw, as the SCAQMD significance criteria are based on the maximum increase. See, e.g., SCAQMD 1993, p. 6-3: "In determining whether or not a project exceeds these thresholds, the project emissions should be calculated…utilizing the highest daily emissions.." The "highest daily emissions" for the modification of an existing facility must be calculated from either the minimum or annual average pre-project daily emissions. Using the "peak" emissions in the pre-project period results in underestimating the "highest daily emissions". This error may also have been made for other emission sources. However, I cannot identify them as the DEIR does not support its assumptions, e.g., are the pre-project hydrogen and electricity demand emissions based on peak days?

The DEIR contains a table that summarizes reported emissions for CO, NOx, VOC, SOx, and PM10 for the entire refinery for the period 2000 to 2013. DEIR, Table 3.1-13. However, this is not adequate to support 2002 to 2003 as valid baseline years for individual process units because the modified units/operations emit only a tiny fraction of the total Refinery emissions. Emissions from a refinery are dominated by the fluidized catalytic cracking unit (FCCU), which emits the majority of the NOx, SOx, CO, and PM10. Any change in the operation of the FCCU (and other large emission sources) would mask changes in emissions from much smaller units such as heater 212 and unit 90. Thus, this table provides no useful information for supporting the 2002-2003 baseline.

IV. EMISSIONS ARE UNDERESTIMATED

My analysis of the emission calculations in Appendix B indicates emissions were significantly underestimated. Critical information, required to support the DEIR's emission calculations, is missing from the DEIR. Thus, the DEIR fails as an information document under CEQA. Further, incorrect methods were used to determine pre- and post-project emissions, which resulted in significant emission underestimates. When the errors and omissions are corrected, air quality impacts due to NOx emissions are significant. The increase in emissions of other pollutants may also be significant, but the DEIR does not contain sufficient information to identify and correct all of the DEIR's errors and omissions.

A. Hydrogen Production Emissions Are Underestimated

The Project requires increased amounts of hydrogen to remove increased amounts of sulfur from the feedstock to the diesel hydrotreater, Unit 90, to meet low sulfur diesel standards. DEIR, p. 3-34. The production of hydrogen generates emissions from boilers, heaters, flaring, and various indirect sources. Thus, the increased demand for hydrogen at Unit 90 increases emissions.

The DEIR estimated the increase in emissions from increased hydrogen production by subtracting average annual post-project emissions during a recession (2006-2008) from annual average pre-Project emissions in the two years prior to start of CEQA review (2002-2003). The DEIR's analysis significantly underestimates the increase in emissions from increased hydrogen demand for four reasons: (1) used wrong post-project period; (2) used wrong measure of significance; (3) used annual averages rather than maximum potential to emit; (3) improperly adjusted emission factors to exclude flaring and indirect sources of emissions; (4) used combined hydrogen demand for Units 89 and 90.

Hydrogen production emissions were calculated by multiplying the increase in annual average hydrogen demand (511 mmscf/yr)[6] by emission factors in pounds per million standard cubic feet (lb/mmscf) based on the 1998 Hydrogen Plant FEIR.[7] The increase in hydrogen demand was calculated as the difference between post-project demand (4,197.50 mmscf/yr) in 2006-2008 and pre-project demand (3,686.50 mmscf/yr) in 2002-2003. DEIR, p. B-4.

1. <u>Wrong Post-Project Period</u>

The DEIR estimated the increase in hydrogen demand based on post-project demand in 2006-2008, the first three years after startup of the Project. DEIR, p. B-4. The DEIR does not state any basis for selecting 2006 to 2008 as the post-project period. Refinery-wide emissions in Table 3.1-3 indicate that emissions in 2007 were among the lowest reported over the period 2000 to 2012 for CO (next to lowest), NOx (lowest), VOC (lowest), and PM10 (third lowest). Further, this period corresponds to a severe recession, during which fuel demand, and thus refinery emissions, would have declined. Thus, there is ample reason to suspect that the DEIR's choice underestimates hydrogen production emissions.

Further, there is no evidence in the record that this period encompasses the day on which maximum hydrogen demand could occur or what I refer to as the peak day. Refiners can adjust product yields in response to price and other market conditions by varying refinery processes and the types of crude oil that is refined. The DEIR fails to disclose the peak day hydrogen demand allowed by the design of Unit 90. This is a serious omission.

The selected post-project period corresponds to a recession, when the demand for fuels such as diesel was depressed. Thus, this period likely does not contain the peak day. Further, production of diesel has been trending up since 2008 due to significantly higher price margins for diesel relative to gasoline and growing diesel exports.[8]

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[6] mmscf/yr = million standard cubic feet per year.
[7] Environmental Audit, Inc., Air Products and Chemicals, Inc. Hydrogen Facility and Specialty Gas Facility, Final Environmental Impact Report, Prepared for the City of Carson, SCH No. 97071078, June 1998 (Hydrogen Plant FEIR).
[8] See: U.S. Becoming 'Refiner to the World' as Diesel Demand Grows, August 7, 2013, Available at: http://www.cnbc.com/id/100943620; U.S. Refinery Yield of Distillate Fuel Oil, Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MDIRYUS3&f=M and Distillate Yields at U.S. Refineries are Rising, Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=4590.

The increase in hydrogen demand facilitated by the Project should have been based on permit limits, if any. Otherwise, the design throughput of Unit 90 in barrels per calendar day, as modified by the Project, should have been used to calculate the maximum increase in emissions. This amount of hydrogen must be used to calculate peak day emissions. This key metric, design hydrogen demand for Unit 90, is essential to estimate maximum day hydrogen production emissions. It is not disclosed in the record. Thus, the DEIR fails as an informational document under CEQA.

2. Improper Measure of Significance

As discussed above, the post-project emissions should be based on the maximum potential to emit, determined from either permit limits or the physical design of Unit 90, given Project modifications. This value is not disclosed in the DEIR.

In the alternative, if neither of these limits is available and actual post-project data must thus be used, daily average hydrogen production over the relevant period of record must be provided to support the peak day choice. In this case, daily hydrogen demand data should have been provided for the period 2000 to 2013. This would allow determining whether hydrogen use during the 2006-2008 recession, when diesel demand likely declined, is representative of the peak post-project day. Without actual, measured daily hydrogen use data, it is impossible to evaluate whether the post-project emissions represent the peak day.

I cannot revise the DEIR's estimate of hydrogen demand emissions because the DEIR does not include any daily hydrogen use for the period 2000 to 2013. However, the peak day hydrogen use is certain to be much higher than the annual average daily hydrogen demand during a recession that was used to estimate emissions.

3. Improper Use of Annual Average Day To Determine Maximum Daily Emissions

The increase in hydrogen demand in the DEIR is reported as a three year average. The daily average demand was estimated by dividing the annual average demand by 365 days. Thus, the daily annual average hydrogen demand was used to estimate emission increases. The CEQA significance criteria are based on peak day emissions. Thus, emissions on the maximum or peak day must be used, not the average annual day. The ratio of the peak day to the average day can vary by factors of 2 to 10. The DEIR does not contain any daily hydrogen demand data, which is required to identify the peak day and thus fails as an informational document under CEQA.

4. Improper Adjustment of Hydrogen Production Emission Factors

The Project changed the hydrogen distribution piping to enable exclusive use of high purity hydrogen at Unit 90 and the use of lower purity hydrogen currently produced at the Refinery at other units. DEIR, p. 1-9. The Project imports this high purity hydrogen from an off-site hydrogen plant, the Air Products Hydrogen Facility in Carson. The emission calculations assume that 100% of the hydrogen is supplied by this off-site facility. DEIR, pp. 3-35, B-4.

The emission factors used to calculate the increase in emissions from increased use of hydrogen are cited to the FEIR for this Carson Hydrogen Plant, *viz*. "City of Carson, EIR for the Air Products Hydrogen Facility and Specialty Gas Facility (SCH#97071078), June 15, 1998." DEIR, p. B-4. This FEIR is called the "Hydrogen Plant FEIR" in these comments. The DEIR does not cite a specific page or table in the Hydrogen Plant FEIR.

My review of the Hydrogen Plant FEIR indicates that the emission factors used in the DEIR to estimate hydrogen emissions are not presented in the Hydrogen Plant FEIR. Rather, they must be calculated from peak day operational emissions and the design hydrogen production of 96 million standard cubic feet per day (mmscfd). Hydrogen Plant FEIR, p. 3-12 and Table 5-8. When one assembles all the relevant data and makes this calculation, one discovers that the DEIR improperly reduced emissions reported in the Hydrogen Plant FEIR by excluding most emission sources.

a. Flaring and Indirect Emissions Were Improperly Excluded from Hydrogen Production Emission Factors

Emissions from hydrogen production arise from a boiler, a reformer heater, fugitive sources (valves, pumps, flanges, etc.), flaring events, and various indirect sources, including material delivery, truck transport of CO2, and worker travel. My analysis of the Hydrogen Plant FEIR indicates that the DEIR excluded most of the NOx emissions from hydrogen production without disclosing or justifying the deletions in the DEIR.

The emission factors that the DEIR used to estimate hydrogen production emissions are based only on the Hydrogen Plant boiler and reformer heater. All other sources of emissions required to produce hydrogen -- flaring emissions and all indirect emissions -- were inexplicably excluded. The Title V Permit for the Carson Hydrogen Plant[9] does not contain any limits that would prohibit or restrict flaring. Thus, these emissions should have been included in the emission calculations. My analysis of the Carson Hydrogen Plant emissions is summarized in Table 1.

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[9] SCAQMD, Facility Permit to Operate, Air Prod & Chem Inc., 23300 S. Alameda St., Carson, CA, Facility ID: 003417, February 14, 2014 (Hydrogen Plant Title V Permit).

Table 1.
Carson Hydrogen Plant Emissions[10]

	Units	CO	VOC	NOx	SOx	PM10	PM2.5
1. DEIR Emission Factor	lb/mmscfd	**1.63**	**1.63**	**2.5**	**0.07**	**1.95**	**1.95**
2. Hydrogen Plant FEIR Emissions	lb/day	229	173	1437	10	198	198
3. Hydrogen Plant Emission Factor	lb/mmscfd	2.39	1.80	14.97	0.10	2.06	2.06
4. Boiler/Reformer Heater Emissions	lb/day	156	156	240	7	187	187
5. Boiler/Reformer Emission Factor	lb/mmscfd	**1.63**	**1.63**	**2.50**	**0.07**	**1.95**	**1.95**

Line 1 presents the emission factors used in the DEIR to estimate the increase in emissions from increased use of hydrogen. DEIR, p. B-4. Line 2 presents the emissions from producing hydrogen for the "peak day" from the Hydrogen Plant FEIR. The peak day, generally reported as the maximum potential to emit, is the correct metric to estimate post-project emissions. See Comment II. Line 3 presents the emission factors that I calculated from the Hydrogen Plant FEIR's peak day emissions and the design hydrogen production of 96 mmscfd. These emissions factors are shown in red.

A comparison of Line 1 with Line 3 (red) shows that the DEIR underestimated the emissions of all pollutants by gerrymandering the emission data that it cites. The underestimate of NOx (2.5 vs. 15 lb/mmscf) is notable. The emission factors on Line 3 (red) should have been used in the DEIR to estimate the increase in emissions from increased use of hydrogen by the Project.

The only way to reproduce the emission factors used in the DEIR, p. B-4, is to calculate them from only the boiler/reformer heater emissions. Hydrogen Plant FEIR, Table 5-8. This calculation is shown in Table 1, line 5, which exactly reproduces the emission factors used in the DEIR, shown in line 1. Thus, the DEIR has significantly underestimated the increase in emissions from the increased use of 511 mmscf/yr of hydrogen by excluding the major sources of emissions required to produce the hydrogen, including flaring emissions and all indirect emissions. CEQA Guidelines Section 15378(a) requires that reasonably foreseeable indirect impacts must be analyzed as part of the project. The revised emissions, based on the emission factors in Table 1, line 3, are presented in Table 4.

The use of the proper NOx emission factor, 15 lb/mmscfd, would increase hydrogen production NOx emissions from 3.5 lb/day (DEIR, Table 3.3-7) to 21 lb/day.[11] This increases

[10] DEIR Emission Factor from DEIR, p. B-4; (2) Hydrogen Plant FEIR Emissions from Hydrogen Plant FEIR, Table 5-8, p. 5-27; (3) Hydrogen Plant Emission Factor = Hydrogen Plant FEIR Emissions (2)/H_2 production of 96 mmscfd from Hydrogen Plant FEIR, p. 3-12; (4) Boiler/Reformer Heater Emissions from Hydrogen Plant FEIR, Table 5-8, p. 5-27; (5) Boiler/Reformer Emission Factor = Boiler/Reformer Heater Emissions/96 mmscfd.

[11] Revised hydrogen production NOx emissions = 3.5 x 14.97/2.5=20.96 lb/day.

the total Project NOx emissions from 14.06 lb/day to 32 lb/day.[12] Other underestimates in NOx emissions, discussed elsewhere in these comments, result in peak day NOx emissions much greater than the significance threshold of 55 lb/day. [13] Thus, the increase in NOx emissions due to the Project is significant. The DEIR failed to disclose and mitigate this impact.

b. Flaring Emissions Are Higher than Otherwise Disclosed

The NOx flaring emissions reported in the 1998 Hydrogen Plant FEIR were based on an emission factor that the EPA has since determined underestimates flaring emissions. The Hydrogen Plant FEIR estimated flaring emissions using a NOx emission factor of 0.036 lb/mmbtu.[14] The U.S. EPA recently revisited flaring emission factors and now recommends raising the NOx factor to 2.9 lb/mmbtu based on substantial test data.[15] If this updated NOx flaring emission factor were used to calculate hydrogen demand flaring emissions, it would increase flaring emissions from 1,437 lb/day to 115,800 lb/day. This would increase total Project operational NOx emissions from 14 lb/day to 115,814 lb/day. This exceeds the NOx significance threshold of 55 lb/day by a huge amount, indicating a highly significant, unmitigated air quality NOx impact that was not disclosed in the DEIR.

5. <u>Hydrogen Production Emission Factors Improperly Based on Combined Demand</u>

The increase in hydrogen demand due to the USLD Project was calculated for Units 89 (jet hydrotreater) and 90 (diesel hydrotreater) combined as they reportedly are not separately measured. DEIR, p. 3-35. The Project would modify Unit 90, but not Unit 89. DEIR, p. 3-35. All of the increase at these two units was attributed to Unit 90 to reportedly ensure worst-case emissions. DEIR, p. 3-35, p. B-4.

Attributing 100% of the combined annual average hydrogen demand to Unit 90 does not ensure a worse case and may underestimate peak day emissions. If the hydrogen demand of unit 89 decreased, this decrease could offset increases at Unit 90, whose hydrogen production would increase due to the Project. A decrease in hydrogen demand at unit 89 is plausible, as the demand for jet fuel could decline while the demand for diesel is projected to increase.[16] Thus, combining these two units could mask a much larger increases in hydrogen production at Unit 90 than disclosed. The DEIR should separate these two units' operation using a different metric,

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[12] Revised ULSD operational NOx emissions = 14.06 – 3.5 + 21 = 32 lb/day.

[13] Revised increase in NOx emissions (Table 3.3-7) = 19.5 (replacement heater) + 21 (hydrogen production) +24.9 (electricity demand) + 14.8 (truck transport) = **80.2 lb/day.**

[14] Emission factor used to estimate flaring emissions in the Hydrogen Plant FEIR is estimated from Appendix B, p. 10, "Ground Level Flare Flaring Emissions": 1140.5 lb/day/[(1.32 x 10^9 Btu/hr)(24 hr/day)(mmBtu/10^6 btu)] = **0.036 lb NOx/mmBtu**.

[15] U.S. EPA, Emissions Estimation Protocol for Petroleum Refineries, Draft, August 2014, Table 6-2.

[16] See: U.S. Diesel Fuel Demand to Peak in 2015 While World Demand Will Grow Through 2030, Available at: http://www.fuelsinstitute.org/news/PR102914.shtm. Short-term Energy and Winter Fuels Outlook, Available at: http://www.eia.gov/forecasts/steo/report/us_oil.cfm.

perhaps feed throughput, steam use or electricity use, which is separately measured, to assure a worst-case is analyzed.

B. Replacement Heater Emissions Are Underestimated

Heater B-201 was removed from service at Unit 90 and replaced with a new, "functionally identical" heater, B-401. NOx emissions from heater B-201 were controlled by low NOx burners, while NOx emissions from the new replacement heater B-401 are controlled by low NOx burners and selective catalytic reduction (SCR). DEIR, p. 3-34.

The DEIR explains that post-project emissions are based on the "maximum potential to emit" while pre-project emissions are based on "actual operating conditions for 2002 and 2003." DEIR, p. 3-34. However, a comparison of the emissions from these two "functionally identical" heaters (DEIR, Table 3.3-7) in Table 2 is not consistent with this explanation.

Table 2.
Comparison of Heater B-201 and B-401 Emissions (DEIR, Table 3.3-7)

	CO	VOC	NOx	SOx	PM10	PM2.5
Heater B-201	22.65	4.53	30.5	2.5	4.85	4.85
Heater B-401	6.04	5.44	4.96	4.19	5.83	5.83

This table indicates post-project (Heater B-401) emissions of VOC, PM10, and PM2.5 are consistently 20% higher than pre-project emissions (presumably in direct proportion to the assumed increase firing rate as they were estimated from emission factors expressed as lb/mmbtu), while CO and NOx emissions have both declined significantly. The NOx decline is consistent with the installation of SCR, which removes about 90% of the NOx (DEIR, p. 2-7), but the CO decline is not consistent with the project description and reveals a fundamental error in the method used to estimate Project emission increases. These anomalies are further discussed below.

1. Post-Project Emissions (Heater B-401)

The DEIR states that post-project emissions from new heater B-401 are based on the maximum potential to emit, assuming the heater operates at 34 mmBtu/hr, calculated from permit limits for SOx (0.0052 lb/mmBtu), NOx (0.21 lb/hr or 5 ppm), and CO (0.25 lb/hr or 10 ppm) and from "SCAQMD-approved emission factors" for other pollutants (VOC, PM10, PM2.5). DEIR, p. 3-34, B-3. However, the DEIR does not show the calculations.

a. Permit Limits Used To Estimate Post-Project Emissions Are Not Supported

We obtained the most recent Title V Permit from the SCAQMD for the Wilmington Refinery to verify these asserted emission limits, used to estimate post-post emissions.[17] The most recent Title V Permit for this facility was issued August 15, 2014, just prior to the release of the DEIR. This permit has not been updated to include new heater B-401. Rather, it still lists heater B-201 as the only Unit 90 charge heater.

The use of permit limits for SOx, NOx, and CO to determine post-project emissions is potentially reasonable, if supported by the Title V Permit. However, I cannot verify these limits as the SCAQMD has not updated the Refinery Title V Permit. Review of the actual permit limits is essential to evaluate their relevance for several reasons.

First, permits often contain exceptions to limits, such as during unit startups and shutdowns. These exceptions are allowed in the Refinery Title V Permit for other similar units.[18] These exceptions determine maximum daily emissions. In the case of NOx, for example, the SCR, typically designed to remove 90% of the NOx, would not operate during startups and shutdowns due to catalyst temperature limitations. Thus, NOx emissions could be substantially higher, ten times higher for a 90% efficient SCR, during startups and shutdowns. These startup/shutdown conditions would determine the maximum day for purposes of calculating maximum post-project emissions.

Second, permit limits are typically accompanied by an averaging time, such as daily, hourly, or annual average. These averaging times must be reviewed to assure that the emission increase calculated from the permit limit represents the maximum day, rather than an annual average or monthly average day.

Third, if the permit does not require adequate testing to assure permit limits are met, the permit limits cannot be used to establish maximum post-project emissions. The permit limits for heater B-201, for example, do not require any testing for NOx, PM10, or PM. Only periodic

[17] SCAQMD, Facility Permit to Operate, Phillips 66 CO/LA Refinery Wilmington PL, 1660 W Anaheim St, Wilmington, CA 90744, Facility ID 171107, August 15, 2014 (Refinery Title V Permit).

[18] See, e.g., Refinery Title V Permit, p. 3, Condition A99.1: "The 9 ppm NOx emission limit(s) shall not apply when the equipment is in startup, shutdown, or on-line fuel transfer periods (for NOx)."

stack tests are required for CO.[19] Compliance testing required for replacement heater B-401 is unknown as the Title V Permit has not yet been updated to include this change and the DEIR failed to report it. However, if compliance testing for new heater B-401 is similar to that for old heater B-201, the DEIR cannot rely on B-401 permit limits for NOx, PM10, PM2.5 or CO to estimate maximum potential to emit without requiring additional monitoring as conditions of approval, e.g., continuous emission monitoring (CEMS) for compliance with NOx and CO limits.

Thus, the permit limits used to estimate post-project emissions of NOx, CO, and SOx are unsupported. Basing post-project emissions on these limits likely underestimate the maximum daily emission increase, especially if the limits include exceptions for startups and shutdowns.

b. Permit Limits Underestimate Post-Project NOx Emissions

The post-project NOx emissions from heater B-401 were calculated assuming the heater emits 0.21 lb/hr for 24 hours (0.21x24 hr/day = 5 lb/day), based on an unsupported permit limit. DEIR, p. 3-34, B-3. However, these are controlled emissions, assuming the SCR is on line and is removing 90% of the NOx. The uncontrolled emissions would be 50 lb/day or about 2 lb/hr. During startups and shutdowns of Unit 90, the SCR is offline. Assuming the SCR is offline during a Unit 90 startup or shutdown for only 4 hours, the NOx emissions would increase from 5 lb/day to 12 lb/day. In a worst case, assuming the SCR is offline for an entire day, the NOx emissions would increase from 5 lb/day to 50 lb/day. This is sufficient to offset the entire NOx decrease of 30.5 lb/day from shutting down heater B-201 (DEIR, p. B-3), resulting in a NOx increase of 19.5 lb/day (50-30.5 = 19.5) for heater replacement. As this is a plausible scenario, not prohibited by permit, this scenario must be considered in determining the maximum post-project NOx emissions.

This revision, to address periods when the SCR is offline, coupled with others reported elsewhere in these comments, would increase Project NOx emission increases to 80 lb/day.[20] Thus, the revised increase in NOx emissions due to the Project exceeds the CEQA significance threshold of 55 lb/day. If the additional NOx from updating the flaring emission factor is included, NOx emissions would increase to 115,880 lb/day on the peak day, exceeding the threshold by a factor of 21,000. This is a highly significant, unmitigated air quality impact that was not identified or mitigated in the DEIR.

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[19] Refinery Title V Permit, Conditions for unifiner charge heater 79-B-201 at pdf 34: Conditions C1.23 (continuous monitoring of heat rate in mmbtu/hr), D232.1 (continuous monitoring of H2S as surrogate for SOx), and D328.1 (stack test for CO).

[20] Revised increase in NOx emissions as summarized in Table 4 = 19.5 (replacement heater) + 21 (hydrogen production) +24.9 (electricity demand) + 14.8 (truck transport) = **80.2 lb/day.**

c. Permit Limits Underestimate Increase In CO Emissions

Table 2 indicates that pre-project CO emissions (22.65 lb/day) are nearly four times higher than post-project CO emissions (6.04 lb/day) for a "functionally identical" heater with no CO controls. The DEIR attempts to explain this anomaly by noting that "CO emissions are also less because the SCAQMD established a reduced CO emission limit (10 ppm)…" DEIR, p. 3-34. As noted previously, the Title V Permit has not been updated so this claim cannot be verified.

However, an emission limit by itself without accompanying controls will not lower CO emissions. No CO controls are proposed for Heater B-401. Further, VOCs and CO are generally directly related to each other as both are combustion byproducts. The VOC pre-project emissions in Table 2 are less than the VOC post-project emissions. This further suggests that the very large decline in CO emissions is invalid.

The supporting emission calculations in Appendix B clarify that the pre-project emissions are based on "peak emissions during 2002 and 2003" rather than average emissions. DEIR, p. B-3. As explained in Comment II, "peak" emissions should not be used to determine "actual" pre-project emissions as the significance criteria are based on the maximum day. The maximum day cannot be determined by comparing maximum post-project emissions with maximum pre-project emissions.

The maximum day is the highest daily increase that is feasible. This should be determined relative to the pre-project average day or even the pre-project minimum day, but not the pre-project maximum day, as apparently done here. The anomalously high pre-project CO emissions of 22.65 lb/day is presumably based on the maximum day. Thus, it is not a reasonable CO baseline for the new heater and should be rejected. The maximum day CO emissions of 22.65 lb/day leads to the erroneous conclusion that the new heater would significantly reduce CO emissions relative to the old heater, which is unlikely as no CO controls are proposed.

Further, unless the Title V permit is modified to require continuous emission monitoring of CO emissions, there is no assurance that the post-project CO limit of 6.04 lb/day would be achieved. Thus, it is not a reasonable basis to establish maximum post-project emissions. I am unable to determine the correct value for either the pre-project or post-project CO emissions as the DEIR does not include daily heat rate, daily CO emission data for the pre-project period, and the actual permit condition assumed to control CO emissions. My revised CO emissions in Table 4 thus assume the same ratio of pre- to post-emissions as assumed for VOC, PM10, and PM2.5.[21]

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[21] Revised CO emissions, summarized in Table 4: (22.6 lb/day)(1.2) = 27.1 lb/day. The factor of 1.2 is the ratio of VOC post- to pre-project emissions (5.4/4.5 = 1.2).

d. Revised SCAQMD Emission Factors Underestimate PM10 and PM2.5 Emissions

My analysis of emissions data in Table 2 indicates that the DEIR used the same "SCAQMD-approved emission factors" to calculate both the pre-project and post-project VOC, PM10, and PM2.5 emissions.[22] The record contains no evidence that "SCAQMD-approved emission factors" accurately represent post-project emissions on the peak day compared to pre-project emissions for VOC, PM10, and PM2.5. The DEIR should have provided stack tests to confirm that these emission factors are fair estimates of peak day emissions.

There is reason to believe that post-project emissions of PM10 and PM2.5 are underestimated by using the same emission factors for the pre- and post-project conditions. The Project would increase peak day PM10 and PM2.5 emissions from the use of SCR to control NOx.

An SCR injects ammonia into the flue gas stream. The SCR catalyst converts some of the SO2 into sulfur trioxide (SO3). The ammonia and sulfur trioxide react downstream from the SCR to form ammonium sulfates, which are components of PM10 and PM2.5. Thus, the SCR should have resulted in an increase in the emission factors used for both PM10 and PM2.5. This increase is not reflected in the emission estimates as the same emission factor was used to calculate both pre- and post-project PM10 and PM2.5 emissions. The small increase in PM10 and PM2.5 shown in Table – is due solely to an increase in firing rate from 28 mmBtu/hr to 34 mmBtu/hr.

2. <u>Pre-Project Baseline Emissions (Heater B-201)</u>

The pre-project baseline emissions for heater B-201 were based on "peak emissions during 2002 and 2003". DEIR, p. B-3, note (1). The basis for this approach is stated as: "During 2002 and 2003, B-201 did not operate at the maximum rated capacity on a daily basis. Therefore, the emissions for the peak operating day were used to evaluate the increase in emissions associated with the ULSD Project." DEIR, p. B-3, Approach. This method of calculating pre-project emissions is wrong.

The "approach" language in the DEIR assumes that the "maximum rated capacity on a daily basis" is the proper test for baseline emissions. However, the "maximum rated capacity" of 34 mmBtu/hr is the permitted capacity, which determines the post-project peak day, not the pre-project baseline. A long line of Court of Appeal decisions holds that impacts of a proposed project are compared to "actual" conditions at the time of CEQA analysis, not the level that could have or should have been present, e.g., "the maximum rated capacity." As heater B-201 apparently did not operate at the maximum rated level during the baseline period, the maximum rated level is not the "actual" rate.

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[22] The ratio of pre-project to post-project emissions of VOCs, PM10, and PM2.5 is the same (0.84), indicating that these emissions were calculated using the same pre- and post-emission factor, varying only the firing rate. Thus, the DEIR assumed a baseline firing rate of 35 mmBtu/hr x 0.84 = 29 mmBtu/hr.

The correct baseline is "actual" average to assure an estimate of "highest daily emissions" to compare to the significance thresholds. I cannot correct this error as the DEIR does not contain any of the supporting data that was used to select the maximum pre-project daily emissions.

The significance criteria determine how both the pre-project and post-project emissions are calculated. As discussed elsewhere in these comments, the SCAQMD significance criteria used to judge Project impacts are based on peak day emissions. If the increase in emissions on the peak day equals or exceeds the significance criteria, the impact is significant. Thus, pre-project and post-project emissions must be calculated to estimate the peak day, not the average or minimum day. The peak day should be calculated as the difference between actual emissions on the average day in the pre-project period and the maximum daily emissions in the post-project period, established by either permit conditions or equipment design.

The selection of 2002 and 2003 may be reasonable (if supported by actual daily data not currently in the record) for the pre-project period, but the use of the peak daily emissions during this period is not a valid baseline. While CBE v. SCAQMD concluded that "[i]n some circumstances, peak impacts or recurring periods of resource scarcity may be as important environmentally as average conditions..", here there is no demonstration that peak impacts in the baseline are as important environmentally as any other condition.

The DEIR does not contain any of the information used to select peak daily emissions of CO, VOC, NOx, SOx, PM10, or PM2.5 during 2002 and 2003. I would expect there would be continuous emission monitoring data, reported on at least an hourly basis, for heat rate (mmBtu/hr), NOx, and perhaps CO. Some subset of this data likely was used to determine the pre-project peak daily emissions. This data is critical to evaluating the reasonableness of the selected baseline emissions. It is critical, for example, to determine whether a spike in operations just happened to occur prior to environmental review. This essential data was not provided in the DEIR nor in responses to our PRAs. Without this data, one cannot determine actual emissions prior to the project or evaluate whether the peak values are outliers, occurring only once or very few times over the two year period, or whether they are representative of annual operating conditions over the two year period. Thus, there is no support for the heater B-201 baseline emissions and no support for the claimed total emission changes due to replacing heater B-201 with heater B-401.

C. Electricity Demand Emissions Are Underestimated

The method used to calculate the increase in electrical demand is not clearly explained in the DEIR. The text of the DEIR suggests the increase in electrical demand is just that due to certain new equipment, while Appendix B suggests it is the net increase of unspecified equipment, relative to unspecified pre- and post-project conditions.

First, the DEIR asserts that it estimated the increase in emissions from the increase in electricity use based only on the horsepower (hp) rating of certain new equipment totaling 1,035 hp, as follows (DEIR, p. 3-35):

- Pumps, fans, air coolers: 835 hp
- Recycle gas compressor: 200 hp

It is unclear if all new equipment is included in this estimate as it lumps all of the pumps, fans and air coolers together. The estimate should be supported with a list of each piece of equipment and its vendor specifications, required to verify the hp ratings. There are reasons to suspect the electrical demand may be underestimated.

First, the DEIR notes that the existing recycle gas compressor was modified to "double its capacity by replacing its internals with a larger rotor." DEIR, p. 2-7. Elsewhere, when the DEIR addresses the emission calculations, it only notes "Phillips reactivated a 200 hp recycle gas compressor" (DEIR, p. 3-35), without mentioning that the capacity was doubled, suggesting the increase should have been 400 hp, rather than 200 hp.

Second, the DEIR identifies a new ULSD shipping pump, two new pumps for handling jet and diesel blendstocks, and one new pump to create separate facilities for handling jet and diesel fuel. DEIR, p. 2-8. In addition, though not mentioned, a vaporization unit (air heater and air blower) would be required to supply ammonia vapor to the SCR system. These could easily exceed 835 hp total. There is no way to determine whether all of this new equipment is included in the 835 lumped "pumps, fans, and air coolers" electrical demand as the DEIR does not list the equipment and provide vendor specifications.

These two items (835 + 200=1035) sum to a total increase in electricity demand of 1,035 hp or about 18,623 kilowatt-hours per day (kwh/day). This kwh/day increase was converted into an emission increase using SCAQMD emission factors. DEIR, p. B-5.

In the supporting emission calculation in Appendix B, the DEIR presents this information differently. There, it reports pre-project power of 640 hp and post-project power of 1,675 hp, resulting in a net increase of 1,675-640 = 1,035 hp. DEIR, p. B-5. This suggests the 1,035 hp estimate is not just "new equipment".

1. <u>Electricity Demand Is Unsupported</u>

The increase in electricity demand is not supported in the record. The DEIR does not explain how the pre-project baseline electricity demand of 640 hp was selected. It is simply stated with no support. Is it the average day demand in 2002-2003, or some other period, based on actual measurements? Or is it the peak day demand, as used to determine the baseline for heater emissions? Or is it some other metric, such as the sum of the pre-project design basis horsepower ratings of all electrical equipment in Unit 90? What equipment is present in the 640 hp lump sum estimate for pre-project demand? Without answers to these questions, it is impossible to evaluate whether reported emission increases from increased electricity demand are correctly calculated. Thus, the Project description is inadequate to support the conclusions reached in the DEIR.

The DEIR also fails to support the post-project electrical demand. It simply states the horsepower rating of groups of equipment without providing a process and instrument (P&ID) diagram or other process diagram to show how the electrical equipment fits into the overall process. It also fails to supply the vendor specification sheets for the new equipment, required to confirm the claimed horsepower rating. Thus, the DEIR fails as an information document.

2. Electricity Demand Is Underestimated

The DEIR underestimates the increase in electricity demand as it narrowly includes only the demand for select new or newly activated equipment and none of the increase in electricity use by existing equipment required to otherwise support the Project.

The Project would increase electricity demand by all electrical equipment required to operate Unit 90 itself, both new and existing, plus electrical equipment required to operate supporting equipment, such as sulfur removal and cooling water demand. This was explained in detail in my initial comments on the Project, attached here as **Exhibit 2.**

The Project was designed to reduce the sulfur content of diesel from 500 ppmw to 15 ppmw. Phillips 66 reported the "charge capacity" for desulfurization of diesel (presumably in Unit 90) at its Wilmington Refinery as 32,000 bbl/day in 2014.[23] Thus, Unit 90 would have to remove about 4,700 lb/day of additional sulfur.[24]

The removal of 4,700 lb/day of sulfur would require an increase in hydrotreating, which is partially addressed by the acknowledged changes to Unit 90. However, these changes affect other components within Unit 90 and supporting downstream units. In hydrotreating, which occurs in Unit 90, the sulfur in the feed is reacted with hydrogen in the presence of a catalyst at elevated temperature and pressure. The Title V Permit indicates sulfur is converted to hydrogen sulfide, which is separated from the product (diesel) in a stripper, recovered in the Sulfur Recovery Units, and residuals combusted in Scot Tail Gas Units.

The DEIR does not include any increase in emissions from indirect sources of electrical demand nor from cooling water, but rather only includes the increase in electrical demand due to new equipment required to support Unit 90. Thus, electrical demand emissions reported in the DEIR in Table 3.3-7 and at p. B-5 are underestimated. The DEIR also does not contain any of the information required to estimate these emissions. Thus, the DEIR is deficient as an information document under CEQA.

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[23] EIA Form 840, Available at: http://www.eia.gov/petroleum/refinerycapacity/.

[24] Sulfur in current diesel: (32,000 bbl/day)(304 lb/bbl)(500 lb-S/10^{-6} lb) = **4,864 lb-S/day**.

In my 2004 comments on this Project, I estimated 34,287 kwh/day of electricity would be required to remove an additional 7,400 lb/day of sulfur. Adjusting this to the revised estimate of 4,700 lb/day of additional sulfur removal, yields an increase in electrical demand of 21,800 kwh/day to support both direct and indirect electrical demand compared to the DEIR's estimate of 18,623 kwh/day. Thus, the emission increases reported in the DEIR for increased electrical demand are underestimated by at least 20%. The revised electrical demand emissions, based on this correction, are summarized in Table 3.

Table 3.
Revised DEIR Table 3.3-7
Electrical Demand Emissions

	CO	VOC	NOx	SOx	PM10	PM2.5
DEIR	3.7	0.2	21.3	2.2	0.7	0.7
Revised	4.3	0.2	24.9	2.6	0.8	0.8

D. Steam Production Emissions Are Underestimated

The DEIR asserts no increase in steam production emissions based on a new theory that deviates substantially from the original Project description. In the Addendum to the Negative Declaration, the SCAQMD estimated that the Project would increase NOx emissions by 420 lb/day from steam generation in boilers. These emissions were reported to arise from the steam demand of the new recycle gas compressor, reported as 119,283 lb/hr by the vendor. Exhibit 3. The DEIR continues to identify this new compressor and states its capacity would double. DEIR, p. 2-7.

However, the DEIR now claims this substantial increase in steam demand would not result in an increase in steam production and emissions as the Refinery has an "integrated steam system" that reallocates the same amount of 400 psi and 150 psi steam. DEIR, p. 3-39. As support for this new theory, the DEIR presents pre-project (2002-2003) steam demand of 147.9 Mmbtu per 1,000 bbl feed compared to post-project (2006-2008) steam demand of 147.7 Mmbtu per 1000 bbl feed. DEIR, p. 3-39.

First, the DEIR does not contain any information to support this new theory, such as material balances and process flow diagrams that show how the "integrated steam system" works. Further, it does not contain any data to support the pre- and post-project steam demands, such as daily fuel use, higher heating values, and/or steam production data over the period 2000 to 2013 and permit limits for the subject steam generation equipment. Thus, the DEIR fails as an informational document.

Second, the choice of 2006 to 2008 as the post-project period has all the problems previously discussed for hydrogen production in Comment IV.A.1. This period corresponds to a severe recession and includes the year of lowest refinery-wide emissions, thus underestimating post-project steam emissions. Therefore, the comparison of 2002-2003 steam production to 2006-2008 steam production proves nothing. The post-project emissions should be based on vendor-reported steam demand of 119,283 lb/hr for the new compressor, not actual steam production during a recession.

Third, the steam demand data is for the entire refinery, rather than the equipment modified by the Project. It combines all steam generating equipment (four boilers, gas turbine and heat recovery boiler). DEIR, p. 3-40. This lump sum data could hide increases due to the Project if temporary decreases occurred elsewhere at the Refinery. See Comment IV.A.5 on combined demand. Further, each steam source emits different amounts of pollutants per unit of steam generated. Exhibit 3. Thus, combining them and comparing only steam demand, rather than emissions, could hide emission increases due to the Project.

Finally, the DEIR proposes a mitigation measure to demonstrate that the Project does not cause steam demand to increase. DEIR, p. 3-40. This mitigation measure will not assure that the Project does not increase emissions from steam production for three reasons. First, the duration of the mitigation measures is only five years. Second, the mitigation measure is based on refinery-wide fuel use for steam production rather than Project steam production. Third, it does not report emissions, the metric of interest.

V. SUMMARY

In sum, the DEIR underestimated emissions by improperly calculating both pre-project and post-project emissions. Pre-project emissions were calculated using maximum daily emissions in 2002-2003 rather average daily emissions. Post-project emissions were calculated using annual average emissions during 2006-2008, rather than "highest daily emissions", based on permit limits or physical constraints of the subject equipment. Finally, the DEIR improperly modified certain key emission factors to exclude flaring and indirect emissions, without disclosing the changes. These various flaws significantly underestimated NOx emissions. The increase in NOx emissions, 80 lb/day, exceeds the significance threshold of 55 lb/day and is a significant, undisclosed, and unmitigated impact of the Project.

My revised emissions, based on Comments II through IV, are summarized in Table 4. The changes, relative to the DEIR (Table 3.3-7) are shown in bold. I cannot correct all of the errors in the DEIR's analysis as its calculations are largely unsupported. Thus, a failure to show a change does not indicate agreement, but rather lack of adequate information to evaluate the DEIR, which fails as an informational document.

Table 4
Revised Emissions (lb/day)

Project Component	CO	VOC	N0x	S0x	PM10	PM2.5
Fugitives	0	5.2	0	0	0	0
Replacement Heater	**27.2**	5.4	**19.5**	1.7	1.0	1.0
Hydrogen Production	**3.3**	**2.5**	**21.0**	**0.2**	**2.9**	**2.9**
Storage Tank 331	0	0.2	0	0	0	0
Electricity Demand	**4.3**	**0.2**	**24.9**	**2.6**	**0.8**	**0.8**
Truck Transport	11.6	1.6	14.8	0.1	0.3	0.3
Steam Production	>0	>0	>0	>0	>0	>0
Total	46.4	9.9	**80.2**	4.6	4.9	4.9
Sig. Threshold	550	55	55	150	150	55

Report Prepared By:

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RESPONSE TO COMMENT LETTER 2

Communities for a Better Environment, November 13, 2014

Response 2-1

This November 13, 2014 comment letter was retracted on by CBE on November 14, 2014 and a new comment letter was provided. Please see Comment Letter No. 4 for Response to Comments from CBE.