BOARD MEETING DATE: February 6, 2015 AGENDA NO. 23

PROPOSAL: Communities for a Better Environment's Request for Hearing Regarding Certification of Negative Declaration in Connection with Permitting Tank Project at Philips 66 Carson Refinery

SYNOPSIS: Communities for a Better Environment has submitted documents in which it purports to appeal the Executive Officer's approval and certification of a Negative Declaration that was done as part of the approval of SCAQMD permits for Phillips 66 to construct a new crude oil storage tank and make related changes at its Carson Refinery. This item is for the Board to consider whether to grant Communities for a Better Environment a hearing and, if necessary, to set a hearing date.

COMMITTEE: Not Applicable

RECOMMENDED ACTIONS:
1. Deny CBE's petition to set a hearing date for an appeal of the final negative declaration for the Phillips 66 Carson crude oil storage capacity project; and
2. Reject CBE's appeal of the final negative declaration for the Phillips 66 Carson crude oil storage capacity project.

Kurt R. Wiese
General Counsel

KRW:vmr

Background

On December 12, 2015, the Executive Officer—acting pursuant to Health and Safety Code section 42300(a) and SCAQMD Rule 201—approved permits for a crude-oil storage project at the Phillip 66 refinery in Carson. At the same time, the Executive Officer approved and certified a final negative declaration for the project.

The centerpiece of the Phillips 66 project is construction of a new crude-oil storage tank. The new storage tank will accept shipments of crude oil only by marine vessel. With the new storage tank, Phillips 66 will be able to accept an entire shipload of crude oil from larger marine vessels. Currently, when crude oil is delivered by larger vessels to the Carson refinery, the vessels can only offload part of the shipment because the existing tanks are too small to accept an entire load. Larger vessels currently must make two calls to offload crude oil shipments, offloading part of the shipment and then returning to offload the remainder once the earlier delivery of crude oil in the tank has been processed, and the tank has been drawn down. This aspect of the project will have an environmental benefit by reducing ship emissions.

In addition to the construction of a the crude-oil storage tank, the Phillips 66 project also involves the construction of a water-draw surge tank; increasing the permitted throughput of two smaller crude-oil storage tanks and covering them with geodesic domes; constructing new heat exchangers and a steam trap for water treatment; and installing a new electrical power substation.

Communities for a Better Environment has submitted an appeal to the Governing Board challenging the Executive Officer's approval and certification of a negative declaration for the project. In addition, CBE has submitted a petition to set a hearing date for an appeal. This action is not to consider the merits of CBE's appeal to the Governing Board or the adequacy of the CEQA document. Instead, it is for the Governing Board to decide whether to conduct an appeal proceeding, and if the Board so decides, to set a hearing date.

Legal Standard

CBE's Appeal

CBE claims that it has a right to appeal the Executive Officer's approval and certification of the negative declaration under CEQA Guidelines, 14 California Code of Regulations §15025(b)(1). See CBE's Appeal of Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Storage Capacity Project, p.2, fn.2. Section 15025(b)(1) of the CEQA Guidelines states that:

"(a)…

(b) The decision-making body of a public agency shall not delegate the following functions:

(1) Reviewing and considering a final EIR or approving a Negative Declaration prior to approving a project."

According to CBE, section 15025(b)(1) requires the Governing Board to approve and certify the CEQA document for the Phillips 66 project. CBE's position is that the Executive Officer cannot approve and certify a final CEQA document for the Phillips 66 project because the Executive Officer is not the decision maker for purposes of issuing SCAQMD permits.

There are several problems with CBE's position. First, it overlooks Health and Safety Code section 42300(a) and SCAQMD Rule 201, both of which establish that the SCAQMD's Executive Officer *is* the final decision maker for purposes of issuing air district permits. Health and Safety Code section 42300(a) states that air districts may establish a permit system requiring persons to obtain permits before constructing any article that issues air contaminants, "…from the *air pollution control officer* of the district." SCAQMD Rule 201 requires that persons obtain written permits to construct, "…from the *Executive Officer*." Since the decision maker is the Executive Officer in this case, there is no right to a hearing before the Governing Board under CEQA Guideline 15025(b)(1).

Another problem with CBE's position is that that an appeal of a decision on a negative declaration can only be made "…to an agency's *elected* decision making body, if any." Public Resources Code §21151(c). The SCAQMD Governing Board is an appointed body, not an elected body. *See* Health and Safety Code §40420; 75 Ops. Cal. Atty. Gen. 103 (1992) (SCAQMD Governing Board Members hold appointive offices). Thus, CBE does not have the right to appeal the Executive Officer's decision on the Phillips 66 negative declaration to the Governing Board.

Finally CBE's position contradicts decades of SCAQMD practice. Consistent with the authorities cited above, for decades, SCAQMD Executive Officers have approved permits to construct and have approved and certified the accompanying CEQA documents. On the rare occasions where there has been an attempt to appeal a permitting or CEQA decision to the Governing Board, the Board has declined to conduct an appeal proceeding. There is no reason for the Governing Board to treat this case differently.

CBE's Petition to Set a Hearing Date
CBE has also submitted a petition to set a hearing date for its appeal of the negative declaration for the Phillips 66 project. CBE's petition states that it was submitted pursuant to SCAQMD Rule 1201. *See* CBE Petition to Set Hearing Date, p.2. However, neither Rule 1201 nor the regulation that Rule 1201 is a part of, Regulation 12, apply to this proceeding. They do not apply because this proceeding challenges a CEQA document; it does not seek a hearing on a permit application. Regulation 12 and Rule 1201 apply to proceedings on permit applications. *See* Health and Safety Code §40509; SCAQMD Rule 1201 ("…any person may petition the SCAQMD Governing Board to hold a hearing on a permit application.") CBE has not challenged the Phillips 66 permits.

Instead, CBE has challenged the CEQA document for the Phillips 66 project. Regulation 12 and Rule 1201 do not apply to this proceeding.

Even if Regulation 12 and Rule 1201 did apply to this proceeding, CBE's petition would be untimely. Rule 1201 provides for a public hearing on a permit "application." In this case there are no longer any applications for the Phillips 66 project because the permits have all already been issued. Even if the Board decides that Regulation 12 applies to this proceeding, it should deny CBE's petition as untimely.

Proposal

1. Deny CBE's petition to set a hearing date for an appeal of the final negative declaration for the Phillips 66 Carson crude oil storage capacity project; and
2. Reject CBE's appeal of the final negative declaration for the Phillips 66 Carson crude oil storage capacity project.

Resource Impacts

None

Attachments

1. CBE's Appeal of SCAQMD's Final Negative Declaration for Phillips 66 Carson Tank Project
2. Exhibits to Appeal of Final Negative Declaration for Phillips 66 Carson Tank Project
3. CBE's Petition to Set Hearing Date for Appeal
4. Phillips 66's Opposition to Appeal
5. CBE's Notice of Intent to File CEQA Petition

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BEFORE THE GOVERNING BOARD OF THE
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

In the Matter of **The South Coast Air Quality Management District's December 12, 2014 Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project**	**APPEAL OF APPROVAL AND CERTIFICATION OF THE FINAL NEGATVIE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT**

I. INTRODUCTION

This appeal challenges the South Coast Air Quality Management District's ("District") failure to comply with the California Environmental Quality Act ("CEQA"), Public Resources Code § 21000 *et. seq.*, 14 Cal.Code Regs § 15000 *et. seq*. in its approval and certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project ("Project") on December 12, 2014. The District's approval of a Final Negative Declaration for the Project fails to comply with CEQA because there is substantial evidence in the administrative record of a fair argument that the Project may have a significant, adverse effect on the environment and human health; thereby requiring preparation of an environmental impact report ("EIR").[1]

Because the District Governing Board is the governing body of the agency, the Governing Board has a non-delegable duty under CEQA to certify a Final Negative Declaration.[2] The Governing Board has no published, formal procedures for evaluating and deciding on CEQA documents. Additionally, the Final Negative Declaration approved and certified on December 12, 2014 appears to have been considered, approved and certified solely by District staff. This process makes the District's decision to approve and certify the Final Negative Declaration unclear, and renders the approval and certification procedurally deficient.

Moreover, because the District is also the highest-elected decision-making body for the agency, CEQA requires that the Governing Board provide for an appeal of the District staff's CEQA determination.[3] Accordingly, Communities for a Better Environment ("CBE") hereby requests that the Governing Board deny certification, withdraw and re-consider the District's approval of the Final Negative Declaration for the Project in accordance with its non-delegable authority under CEQA Guidelines, §15025(b)(1), or, in the alternative, appeals the District's approval and certification of the same Final Negative Declaration pursuant to the same CEQA Guidelines section.

II. FACTUAL BACKGROUND

CBE, and its members, particularly those who reside in and around refineries located in the South Coast Air District, have long expressed their concern with refinery operations, their emissions, and potential hazards including flares and accidents that result from refinery operations. Since at least the year 2013, CBE, CBE members and allies have expressed serious concerns with industry trends to increase the transport, storage and refining of dangerous crudes from new North American, domestic and Canadian sources. These concerns have been noted in

[1] *See* CEQA Guidelines, 14 Cal. Code Regs § 15064 (f)(1) ("if a lead agency is presented with a fair argument that a project may have a significant effect on the environment, the lead agency *shall* prepare an EIR even though it may also be presented with other substantial evidence that the project will not have a significant effect." (emphasis added).

[2] CEQA Guidelines, §15025(b)(1).

[3] Cal. Health and Safety Code § 40420; CEQA Guidelines §15025(b)(1) (requiring the decision-making body to approve a negative declaration prior to approving a project); *c.f. Id.* § 15074(f) (providing for appeal of a decision by a local lead agency to adopt a Negative Declaration to the agency's highest elected decision-making body).

correspondence to the District attached hereto at Exhibit A, and have formed the basis for comments submitted to District Staff in relation to project proposals and permit approval processes including the environmental review process for the Phillips 66 Carson Project, as well as other Phillips 66 project proposals throughout the state.

On or about September 6, 2013, the District issued for public review and comment a Draft Initial Study and Negative Declaration for the Project pursuant to Public Resources Code section 21092.

The Project description contained in the Draft Negative Declaration described the project as one involving the following components: (1) installation of one new 615,000 bbl nominal capacity crude oil storage tank, which is identified as tank 2640, and which would be accompanied by a geodesic dome for fugitive emission controls; (2) increasing the permitted throughput limit of two 320,000 bbl nominal capacity existing external floating roof crude oil storage tanks, Tanks 510 and 511, from 4.562 million bbl per year to 18 million bbl per year for each tank and installing geodesic domes on each of those tanks to control fugitive emissions; (3) installation of two new, 2,100 gallons per minute (gpm) crude oil feed/transfer pumps to transfer crude oil into and out of the new tank (Tank 2640); (4) installing of one new, 14,000 bbl nominal capacity water draw surge tank (Tank 2643), including geodesic dome, pumps, and pipelines; (5) installation of three new heat exchangers and one steam trap to assist in water treatment; (6) installation of tie-ins to the manifold of the Pier "T" crude oil delivery pipeline from Berth 121; and (7) installation of one new electrical power substation.

The Draft Negative Declaration and Notice of Intent concluded that the Project components described above would not have a significant impact on the environment and therefore, no EIR would be required for the Project.

SCAQMD invited comments on the Draft Negative Declaration for a period of 30 days, and closed the comment period on October 9, 2013.

On October 9, 2013, prior to the close of the comment period, CBE submitted comments, based on, *inter alia*, the following flaws in the Draft Negative Declaration’s analyses:

1. CBE asserted in comments that the Project description was piecemealed from a larger,

company-wide project to front-end the transport, storage and refining of “advantaged” or “cost advantaged” Western Canadian tar sands, and North Dakota Bakken crudes. In support, CBE included Phillips 66 corporate and market data indicating that Phillips 66 considers “advantaged” or “cost advantaged” crudes to be comprised of Western Canadian tar sands and North Dakota Bakken crudes, and that based on a variety of publicly available data, the company intended to increase shipments of such crudes specifically to its Los Angeles refinery, including the Carson facility,

2. CBE also identified project specifications further indicating that the Project was designed to facilitate the Los Angeles Refinery’s receipt, storage and processing of “advantaged” crudes;
3. CBE pointed to substantial evidence, including reports, data and other scientific information showing why such new crude would cause significant environmental impacts including but not limited to, increased air emissions and risks of hazards as a result of sulfur corrosion from higher-sulfur content crudes; and
4. CBE highlighted the cumulatively considerable, existing burden in the area surrounding the project, specifically in the City of Carson, and in Wilmington.

In January 2014 CBE members and staff met with District staff and members of the Governing Board about another project, and asked for updates and information about the Phillips 66 Carson Project. CBE staff and members specifically asked the District to consider the health and hazards impacts that could result from increasing the amount of tar sands and Bakken crudes blended in Los Angeles refinery crude slates, noting the Phillips 66 Los Angeles refinery in particular. Between February and November 2014 CBE staff and members made additional, repeated requests for information regarding the Project from District staff and some members of the Governing Board, both individually and during public comment at regular Governing Board meetings, and for information specifically regarding the air emissions and health impacts of transporting, receiving and refining tar sands and Bakken crudes.

Since October 2013, CBE and other environmental health and justice organizations have submitted extensive comments on other projects proposed by Phillips 66 in Santa Maria, San

Luis Obispo County, and in Rodeo, Contra Costa County, as well as other non-Phillips 66 projects to transport, store and refine tar sands and Bakken crudes. In these comments, CBE, and other allied environmental health and justice organizations, advocates and technical experts, have exposed new information regarding the potential for highly dangerous fugitive and operation emissions from both process and storage equipment, and the increased risks of potentially catastrophic hazards associated with such crudes.

A relevant selection of these comments and other relevant documents are attached hereto in Exhibits.

On December 12, 2014, after over a year of reviewing and responding comments District staff published its Notice of Determination and Project approval, finalizing and certifying the same Draft Negative Declaration released on September 6, 2013 for comment, as the Final Negative Declaration for the Project.

On December 22, 2014, CBE staff received by mail, the District's notice of determination, project approval and approval of the final negative declaration. The Notice and Project approval documents indicate that the Final Negative Declaration was certified on the same day the District issued its Notice of Determination: December 12, 2014.

Despite the names of all Governing Board members being listed on the second page of the final negative declaration, the Governing Board has not approved the project and the final negative declaration for the Project is not reflected in any publicly available SCAQMD Board meeting agendas or minutes documents.[4] Thus, while the notice received by CBE indicates that the final negative declaration was certified, there is nothing contained on the record to indicate that it was considered by the Governing Board. In fact, the list of all Governing Board members affirmatively misleads the public that the Governing Board has reviewed the document, when it

[4] The only reference to the Governing Board's consideration of the Draft or Final Negative Declarations for the Project that appear to be publicly available, is found in the Governing Board Agenda packet for the December 5, 2014 regular Governing Board meeting. That agenda, and "Attachment C" to the agenda, are attached hereto at Exhibit Q. The attachment indicates only that the Governing Board reviewed a summary of the active projects for which the District is the lead agency wherein the Draft Negative Declaration for the Project was included. District's Staff's description of that status of the Draft Negative Declaration at the time of the Board meeting provides only that the Staff's consultant "is making edits to the responses and finalizing the Draft ND." (*See* Final Negative Declaration, Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project.)

has not.

In response to the comments submitted by CBE on October 9, 2013, District staff claim the following, *inter alia*: (1) CBE's characterization of project specifications indicating that the Project may be designed to facilitate the increased transport, storage and processing of tar sands or Bakken crudes is mistaken as CBE misunderstands the refinery's operations, and the purpose of the Project is merely to increase efficiency and capacity to offload and store larger crude tank deliveries made by marine vessel to the Los Angles Refinery; (2) that CBE's characterization of any increased emissions and/or significant environmental impacts including cumulative impacts is similarly misguided as CBE misunderstands the purpose of the Project; and (3) that the Phillips 66 Los Angeles Refinery has already been receiving, storing and processing Canadian crudes including tar sands crudes and tar sands crude blends since 2002, and the District has included in its response to Comments, new information to support this claim, which was not previously released or made publicly available at any time during the comment period.[5]

The District's revealing of new information at the same time in which its staff has rubber stamped a cursory environmental review document, itself requires immediate withdrawal of the District's approval of the Final Negative Declaration for the Project, and requires reconsideration of the appropriateness of a negative declaration under the circumstances. In particular, the Final Negative Declaration fails to analyze the current and post-project crude quality baseline, as required by CEQA.

In public statements made by Phillips 66 representatives and through the environmental review process for its two additional projects proposed in San Luis Obispo and Contra Costa County, Phillips 66 continues to expose additional information regarding its plans, and its execution of its plans to transport, process and refine tar sands and Bakken crudes at all of the company's California refineries. For example, in a transcript from an investor conference call from the third quarter of 2014, Phillips 66 Chairman and CEO is quoted stating that the company will "get **to 100% advantaged crude in the next year"** or so as we continue to move these

[5] *See generally*, Final Negative Declaration, Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project; and at F-46.

projects forward around infrastructure.[6] Such statements and information find further support in Project applications and related application documents including correspondence between District staff and Phillips 66 representatives, attached hereto in exhibits. All of these facts require the District to immediately withdraw the its approval of the Final Negative Declaration, as the document still fails to account for the impacts that stem from Phillips 66's change in crude slate, as further described below.

On January 2, 2014 CBE sent a letter to SCAQMD staff requesting withdrawal of its approval of the final negative declaration as a result of notice issues, some of the issues raised above, in comments, and in the District's responses to comments. After hearing no response from District staff, CBE hereby files this appeal to the Governing Board.

III. GROUNDS FOR APPEAL

CBE appeals the District's approval of the Project's Final Negative Declaration for two reasons. First, District staff does not have authority under CEQA to approve and certify a Final Negative Declaration on its own. Approving final negative declarations is a non-delegable duty of the District Governing Board.[7] Second, the District violated CEQA's mandate that an EIR be prepared when, as in this case, commenters have met the "fair argument" legal standard by presenting substantial evidence that the Project may cause significant adverse health and environmental impacts and when new, material information regarding the project has become available since the close of the comment period.[8] As such, and for the additional reasons briefly herein, and supported by the attached Exhibits we appeal the District's December 12, 2014 final determination approving and certifying the Phillips 66 Carson Project Final Negative Declaration.

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[6] Q3 2014 Transcript at p. 14, attached hereto in exhibits (emphasis added).
[7] CEQA Guidelines, §15025(b)(1).
[8] CEQA Guidelines §15162.

THE DISTRICT MUST PREPARE AN EIR FOR THIS PROJECT

1. CEQA provides a low threshold for when an agency must prepare an EIR.

CEQA must be interpreted to "afford the fullest possible protection to the environment within the reasonable scope of the statutory language."[9] CEQA requires a lead agency to assess a project's impacts on the environment.[10] Preparation of an EIR is required whenever substantial evidence in the record supports a *fair argument* that significant impacts may occur.[11] The "fair argument" standard creates a low threshold for requiring preparation of an EIR.[12]

Because issuing a Negative Declaration has a terminal effect on the environmental review process, CEQA provides that a lead agency may only issue a Negative Declaration instead of a full EIR if there is "no substantial evidence, in light of the whole record before the lead agency, that the project may have a significant effect on the environment."[13] An EIR is necessary to resolve "uncertainty created by conflicting assertions" and to "substitute some degree of factual certainty for tentative opinion and speculation."[14] An agency's decision not to require an EIR can be upheld only when there is *no credible evidence* to the contrary.[15]

2. ***The District's decision to approve and certify the Negative Declaration ignores potentially significant impacts from allowing for the increased transport, storage and processing of dangerous domestic and Canadian derived crudes--which the District admits for the first time in responses to comments have been processed in the past at the Lost Angeles Refinery.***

CBE cited throughout its comments evidence that the project is likely to have significant impacts on the environment, especially given the fact that the refinery intends to increase the

[9] *Communities for a Better Environment v. Calif. Resources Agency* (2002) 103 Cal. App. 4th 98, 110.
[10] Pub. Res. Code §§ 21002.1(a), 21061.
[11] *Ocean View Estates Homeowners Ass'n v. Montecito Water Dist.* (2004) 116 Cal.App.4th 396, 399; Pub. Res. Code § 21080(d); CEQA Guidelines § 15384(a) ("'Substantial evidence' as used in these guidelines means enough relevant information and reasonable inferences from this information that a fair argument can be made to support a conclusion, even though other conclusions might also be reached.").
[12] *Ocean View Estates*, 116 Cal.App.4th at 399; *Citizens Action to Serve Students v. Thornley* (1990) 222 Cal.App.3d 748, 754.
[13] Pub. Res. Code § 21080(c)(1).
[14] *No Oil, Inc. v. City of Los Angeles* (1975) 13 Cal.3d 68, 77, quoting *County of Inyo v. Yorty* (3d Dist. 1973) 32 Cal.App.3d 795, 814.
[15] *Sierra Club v. County of Sonoma* (1992) 6 Cal.App.4th 1307, 1318 (emphasis added).

amount of dangerous and dirty domestic crudes, and that this Project will necessarily involve offloading, storage and refining of such crudes at the Los Angeles Refinery. The District's responses to comments concerning the Phillips 66 Carson Project expose the agency's cavalier approach to the serious human health and environmental concerns raised by commenters to that project, as well as other, similar projects. In its responses, the District--for the first time--admits the refinery has been using relatively low percentages of Canadian crude, with Table F-1 showing overall Canadian crude at 9.5% over the years, with the highest percent at 21% in 2013[16] so the refinery has the potential to greatly increase use of this crude oil source.[17] The District states that Phillips 66 not only plans to bring down heavy tar sands and dangerous Bakken crudes in the foreseeable future, but it also concedes that the refinery has been processing the same crude types, without disclosure to the public for a significant amount of time.[18]

Publicly exposing this fact in the same act in which it rubber stamps its minimal review of the Project's potential impacts presents a clear dereliction of the agency's duty to protect the environment and to minimize air emissions in the South Coast.[19] Furthermore, because the District revealed this critical new information for the first time in its responses to comments, it must analyze the resulting impacts.[20] The impacts resulting from the increased transport, storage, and refining of dirty and dangerous crudes in Phillips 66's crude slate must be analyzed in an EIR.

The new information contained in the District's responses to comments also requires

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[16] *See e.g.*, Notice of Determination – Final Negative Declaration Phillips 66, Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project – SCH No. 2013091029, at Appendix F, Response 2-9, F-46.
[17] ND Appendix F, p. F-46,
[18] *See e.g*., *Id.* at F-42.
[19] *See City of Redlands v. County of San Bernardino* (2002) 96 Cal.App.4th 398, 405 (holding that an (EIR) must be prepared under CEQA whenever substantial evidence in the record supports a "fair argument that a proposed project will have a significant effect on the environment" (citations omitted).); *see also*, CEQA Guidelines §15384, and 42 U.S.C. § 7401(b)(1)-(3), (c), *supra*; *and see* Cal. Health and Safety Code § 40001(b) (District rules and regulations may, and at the request of the state board provide for the prevention and abatement of air pollution episodes which, at intervals, cause discomfort or health risks to, or damage to the property of, a significant number of persons or class of persons.).
[20] Pub. Res. Code § 15162(a)(3) (requiring an agency to prepare an EIR where new information of substantial importance shows the project will have significant impacts not discussed in a previous Negative Declaration or more severe impacts than previously discussed).

withdrawal of approval and reconsideration of the Final Negative Declaration for the Project, and requires preparation of an EIR. The District's responses to comments, specifically conceding that Phillips 66 already processes and refines Canadian crude blends including tar sands crudes and as well as domestic Bakken crudes substantiate a fair argument that the Project may cause significant environmental impacts. Moreover, this new information, coupled with Phillips 66's more recent Corporate statements cited above further indicate that there are substantial changes to the circumstances under which the Project is being undertaken, requiring a new environmental review process.[21]

2. The District cannot ignore substantial evidence weighing in favor of preparing an EIR.

Phillips 66's own stated project objectives substantiate at least a fair argument that the Project may cause significant adverse environmental impacts that were not addressed by the District in the environmental review process for the Final Negative Declaration. For example, the District has failed to analyze the potential significant increase in baseline sulfur content in the refinery due to a change in the *average* crude oil slate toward substantially increased Canadian tar sands crude oil, facilitated by the new and expanded storage tanks.[22] The Final Negative Declaration assumes that the project's increased tank storage volume and throughput is only for the purpose of offloading from ships faster and to optimize blending.[23] The District asserts that this is unrelated to and cannot cause any downstream changes in the refinery, and it appears that the District's exposure of the fact that the refinery already processes both Canadian and domestic Bakken crudes is included in responses to comments in order to support this claim.[24]

The District's conclusion, however, is incorrect, and fails to adequately address CBE's comments concerning the impacts resulting from a shift in the quality of crude received and

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[21] *See* CEQA Guidelines § 15162 (requiring preparation of subsequent environmental review documents when there are changes in circumstances surrounding a project proposal, notwithstanding approval or certification of the initial environmental review document.

[22] For the purpose of this appeal, this point is made, notwithstanding the District's claim that there will be no increased to the Refinery's throughput levels.

[23] *See* Final Negative Declaration at pp. 1-3 and 1-5 to 1-6.

[24] Final Negative Declaration Appendix F, at pp. F-42.

stored at the Carson facility.

The record shows that both the District and Phillips 66 are clear that the Project storage tanks will be used for the express purpose of bringing in larger volumes of "advantaged" crude oil from Canada and the Bakken shale, implying a change in the overall crude slate quality by volume, notwithstanding the fact that the Refinery may process some inherently lower volumes of Canadian and Bakken crudes currently and may have in the past. Phillips 66's 2012 Summary Annual Report included in CBE's comments on the Draft Negative Declaration provides a map showing the company's plans to bring increased shipments of what it calls "advantaged crudes" to the LA Refinery, specifically from Canada and from the North Dakota Bakken fields. CBE's comments also quote Phillips 66 representatives stating that the company specifically intends to increase shipments of tar sands and Bakken crudes as "advantaged crudes." There is also more in our comments on the draft ND showing where the company stated its intention to bring these "advantaged crudes" to California. Phillip's Application for Tank 2640, and related documents attached hereto in Exhibits also include emails from the District asking Phillips 66 for more information regarding the new tanks project. These emails provide further documentation of the company's intent to use the Carson facility tanks to receive and store tar sands crudes for use in the refinery's operations.

> "As I mentioned on the phone, **I am requesting additional information in support of your crude tanks applications**. Please provide the following information: • Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics." (Janice West, AQMD, January 10, 2013) . . . (emphasis added).
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> "In the attached table, there are columns for SJV[25] crude, "crude oils", Cal crude, and crude hybrid. **What is the origin of "crude oils"?** (Janice West, AQMD, Sept. 3, 2013) . . . (emphasis added).
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> "**Sorry, I meant *geographic* origin** or other identifier, (similar to California or San Joaquin Valley or Canada), just to identify that column as different and not an average of the others). . . . (Janice West, AQMD, Sept. 3, 2013) . . . (emphasis added).

[25] SJV is San Joaquin Valley – a California crude the company has used historically.

"**Our Crude buyer calls it AWB crude.** [26] **It is from Canada.**" (John W. Matthews, Phillips 66, Sept. 3, 2013) (emphasis added).[27]

Phillips 66's more recent corporate statements also re-iterate the purpose of the tanks. In Phillips 66's 2014 "fact book" description of its "midstream" West Coast operations, the company states the following: *"We are adding additional tankage at our Los Angeles Refinery to increase access to advantaged waterborne crudes."* This statement directly refutes the District's responses to comments and their reliance on the claim that CBE "incorrectly assumes that increasing crude oil storage capacity will result in a change in the quality of crude oil blend that is processed at the refinery." [28]

In response to comments the District states that "[w]hile SCAQMD staff does not dispute that crude oils have varying chemical properties and characteristics, including sulfur content, the commenter makes an unsubstantiated assumption that the proposed project will cause the type of crude oil delivered to the LARC to change, when in actuality, the proposed project would not affect the ability, nor would it have any effect on the types of crude oil feedstocks that can and will be received at the LARC."[29] Taken together these statements and correspondence point to the presence of substantial evidence that the company specifically intends to bring in a higher volume of advantaged crude oils from Canada, and that the storage tanks in the Project are indeed for the express purpose of facilitating this effort.

The AWB Canadian and other Candian tar sands crudes described above in the Application documents, moreover, are heavy, with extremely high sulfur content. At 4%, these crudes rank much higher in the presence of sulfur as compared to other crude oils that are also considered to be high in sulfur content.[30] For example, when compared to the average California crude oils historically used in the refinery, including San Joaquin Valley and other crudes, the

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[26] AWB stands for Access Western Blend, it is a heavy, highly corrosive and high sulfur diluted bitumen, or tar sands blend. *See* crude monitor description of properties, relative index and data available at: http://www.crudemonitor.ca/crude.php?acr=AWB

[27] *See* attached exhibits.

[28] *See* Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project, throughout.)

[29] *See Id*., at F-62.

[30] http://www.crudemonitor.ca/crude.php?acr=AWB; *see also* CBE's Technical comment to the Draft Negative Declaration at p. 13.

California Energy Commission found the following:

> Kern County: In 2004, oil from Kern County accounted for 77 percent of California's total onshore production and over **69 percent of the state's total oil production**. Approximately 58 percent of the crude oil has an API of 18 degrees or less. The Kern River oil field, located in the eastern San Joaquin Valley, accounts for approximately 24 percent of Kern County oil. Kern River oil is characteristically heavy and sour with an API of 13.4 degrees and a sulfur content of 1.2 percent.
>
> Los Angeles Basin: The Los Angeles Basin is a sedimentary plain extending from central Los Angeles south through the Long Beach area. The two largest fields by area in this region are the Wilmington and the Huntington Beach fields with average APIs of 17.1 and 19.4 degrees, and average sulfur contents of 1.7 and 2.0 percent, respectively. [31]

Yet, while CBE's comments to the Draft Negative Declaration identified the need for baseline crude slate data including sulfur content at the refinery as necessary to determine the potential overall increase in sulfur content due to the Project, the District failed to do so.

CBE's comments point out that "The ND should have identified baseline crude slates and sulfur content data at the Phillips 66 Los Angeles refinery complex, in addition to the percent sulfur of the unconventional crudes which can potentially be processed due to the Project changes discussed, and volumes of the baselines and crude changes."[32] The Final Negative Declaration, however, states that "The Draft ND does not include a baseline or future changes in crude oil type refined by the LARC because the proposed project will not change, enlarge, or otherwise impact the types and/or quantities of crude oil that LARC currently and will continue to refine." [33] The Final Negative Declaration bases this assertion on its claim that the distillation unit or "crude" unit limits the refinery operation, and without increasing the crude oil there, nothing downstream could change.[34] This statement cannot be true, because crude oil volume limits at the distillation unit do not limit the percent of sulfur in the crude. Downstream of the

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[31] California Crude Oil Production and Imports, California Energy Commission, APRIL 2006, CEC-600-2006-006, available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF
[32] CBE JMay Draft Negative Declaration Comments at p. 14**.**
[33] Final ND at p. F-62
[34] *See Id*.

distillation unit inside the refinery, it is the capacity of the sulfur processing units such as the hydrotreaters and sulfur recovery units that limit how much sulfur can be processed.[35]

The Final Negative Declaration fails to provide any baseline for sulfur processing such as the hydrotreater and sulfur recovery units and instead, it merely provides the range of sulfur that can be processed -- 1 to 3%. But, within the refinery's design range, a baseline can fluctuate over years, and the introduction of extremely high sulfur Canadian tar sands crude oil can increase that overall sulfur processing level, which can result in large increases in the amount of extremely toxic and corrosive sulfur compounds processed in the refinery. Thus, the Final Negative Declaration failed entirely to evaluate the potential for a significant increase of sulfur, as compared to the baseline, due to the Project.

The Final Negative Declaration notes that because there is a small range of sulfur that the refinery is designed to process, even if very high sulfur crude is introduced, it can will be mixed with lower sulfur crude so that the average level of sulfur goes down to the designed range that the refinery can process. The District states:

> "The commenter's opinions do not take into account the processing of a crude oil blend, and thus do not reflect the operations at the Refinery. At p. F-40
>
> "For instance, if the crude oil to be purchased by the LARC has a sulfur content higher than what can be processed by the equipment, LARC must blend it with a crude oil that has a lower sulfur content, so that the sulfur content of the overall blend falls within the proper specifications. The blend of crude oil that is processed at the LARC contains sulfur between the narrow range of one to three percent based on the processing constraints of the Refinery equipment. In the event that there is no low sulfur crude oil available on-site or for purchase to blend with the higher sulfur content crude oil, the LARC will not purchase the high sulfur content crude oil because it cannot be processed without blending. This process of purchasing and blending crude oils has been in practice at LARC for many years and

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[35] *See generally*, Appendix 3 to Chevron Modernization Project, at Exhibit (X), available at: http://chevronmodernization.com/wp-content/uploads/2014/03/Appendix_3_Overview.pdf and the Norwegian University of Science and Technology, available at: http://www.diva-portal.org/smash/get/diva2:649648/FULLTEXT01.pdf and in attached exhibits.

> will not change as a result of the proposed project. For these reasons, the proposed project will not change the types of crude oil processed by the LARC and will not require any modifications to any crude oil refining equipment at the LARC."[36]

Again, the District mischaracterizes CBE's analysis. CBE did account for the range of sulfur in the overall blend processed at the refinery and the District response fails to include any information relevant to establishing an actual sulfur baseline in the refinery. As described above and in more detail in CBE's comments to the Draft Negative Declaration, the question of sulfur baseline is not about whether the refinery can stay within its designed general range of the percent sulfur in individual crude oils processed, it is total baseline that the refinery *has* been operating at over the last few years, and whether the Project will cause an increase in the *total mass* of sulfur, and the overall refinery *average* sulfur percent in the crude oil, and whether the Project will increase those values within the design range. The design range at the refinery is not the basis for a CEQA evaluation, the actual conditions are.[37]

The potential for a significantly increased sulfur percent in the crude oil processed by the refinery due to the Project also may imply higher volumes of hazardous hydrogen sulfide ("H2S") in the refinery, increased danger of corrosion, and increased accident risks, as discussed in CBE's comments on the Draft Negative Declaration. These concerns and potential significant impacts were dismissed by the District on the basis that there was no change to the *types* of crude oils processed as described above, but since the information above shows that there is substantial information providing a fair argument that the refinery plans for the crude oil tanks to facilitate the introduction of "advantaged crudes" including Canadian tar sands crude oils, the Final Negative Declaration's conclusion is incorrect, and it cannot avoid the need for providing a full review and analysis of the potential for increased hazardous sulfur compounds in the refinery that are hazardous to human health and increase accident risk.

H2S is present in sour crude oil, and is also formed in the refinery from the presence of sulfur in the crude oil. More sulfur in the crude oil could mean more H2S in the refinery. While,

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[36] *See* Final Negative Declaration at p. F-44.
[37] *Communities For A Better Environment v. South Coast Air Quality Management District*, 48 Cal.4th 310, 324.

there are also many other acutely hazardous and corrosive sulfur compounds that are formed because of this, H2S remains a large source, and provides another example of what must be evaluated in accounting for the potential environmental impacts of a change in crude slate at the Los Angeles refinery.

CBE discussed the corrosive and accident hazards from H2S in CBE's Draft Negative Declaration comments, and there is a broad range of materials on this subject available. The District is well aware of this but refused to address issues related to the increase in H2S because it erroneously concluded there is no nexus between the crude oil tanks and the high sulfur crude plans of the company.

A study by the Norwegian University of Science and Technology explains in detail, the history of H2S chemistry in oil refineries.[38] The report summarizes many points about hazardous sulfur chemistry due to sour crude oil as follows:

> "The sulfur compounds in crude oils and natural gas generally exist in the form of free sulfur, hydrogen sulfide, thiols, sulfides, disulfides, and thiophenes. These compounds can cause considerable technical, environmental, economic, and safety challenges in all segments of petroleum industry, from upstream, through midstream to downstream. . . .
>
> The major corrosion problems in oil and gas processing facilities are not caused by hydrocarbons but by various inorganic compounds, such as water, hydrogen sulfide, hydrofluoric acid, and caustic. There are two essential sources of these conglomerates: feed-stock contaminants and process chemicals, including solvents, neutralizers, and catalysts (Nenry & Scott, 1994)."[39]

The 2014 EIR for the Chevron Richmond Refinery Modernization Project also describes this hydrotreating sulfur removal process that is present in refineries, and describes how these impurities can interfere with refinery processes. For example, Section 3.2.2 of Appendix 3 to that document states:[40]

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[38] Production and processing of sour crude and natural gas - challenges due to increasing stringent regulations, Norwegian University of Science and Technology, 2013, http://www.diva-portal.org/smash/get/diva2:649648/FULLTEXT01.pdf
[39] *Id*.
[40] Chevron Refinery Modernization Project EIR, March 2014, Appendix 3, Overview of Oil Refining Process, Chevron Modernization Project, 2013, http://chevronmodernization.com/wp-

> "Another important natural characteristic of crude oil is that different types of crude oil have differing amounts of sulfur content. Sulfur occurs naturally in crude oil, but sulfur content is restricted by federal and State air quality laws in refined products (e.g., there are standards limiting the amount of sulfur that can be present in refined products like gasoline). To meet these regulatory restrictions on sulfur content in refined products, sulfur is removed from the various fractions of crude oil during the refining process. [emphasis added] …
>
> When an oil has less sulfur, it is referred to as being "sweet." Crudes with more sulfur are referred to as being "sour." Although there is no regulatory threshold of sulfur content for dividing sweet crude oils from sour crude oils, oils with less than 0.5% sulfur content are generally referred to as "sweet." …
>
> Most sulfur present in crude oil is bonded within hydrocarbon molecules, although some is present as hydrogen sulfide (H2S) gas . This is different from "elemental" or pure sulfur (a yellow crystalline substance when at room temperature), which is a usable product. During the refining process, the sulfur atom is removed from the hydrocarbon molecule. **This process is called "hydrotreating"** because it includes the use of hydrogen. The hydrocarbon fractions are combined with hydrogen in the presence of a catalyst and elevated temperatures and pressures. The catalyst, temperature, and pressure separate the sulfur from the hydrocarbon molecule and the sulfur combines with the available hydrogen to produce a gas called hydrogen sulfide (H2S). This hydrogen sulfide gas is then treated, as explained below, to create "elemental" sulfur, which is sold as a product by Chevron. The Modernization Project includes several components to allow Chevron to remove more sulfur from the Facility's feedstocks and thereby refine higher sulfur crude oil and gas oil in the future."

Section 3.4.2 of the same document further provides:

> "Hydrocarbons separated in the crude unit distillation process and SDA unit contain naturally occurring sulfur and other natural impurities such as nitrogen and metals. One of the key later steps in the refinery process involves chemical reaction processes that include a "catalyst" – a material that promotes or speeds up chemical reactions to produce either a finished product or another interim material to be processed further, such as in the Cracking step. These impurities can interfere with the cracking processes.

content/uploads/2014/03/Appendix_3_Overview.pdf

An example of the kinds of accidents and releases that can occur in sulfur processing units was listed in a Contra Costa County Northern California website publication, in a summary of refinery accidents. The H2S release described there occurred during a hydrotreater upset:

> "An upset occurred in the straight run hydrotreater unit in the light oil processing area. Subsequently, fires occurred in the vacuum flasher heater furnace and crude unit heater furnace. Hydrocarbons, H2S, and smoke released offsite. Level 3 under CWS, sirens activated."[41]

An added example of the range of potential impacts from the increased presence of H2S is contained in the Agency for Toxic Substance and Disease Registry, (ATSDR) H2S Fact Sheet. That fact sheet states that:

> *"Just a few breaths of air containing high levels of hydrogen sulfide gas can cause death. Lower, longer-term exposure can cause eye irritation, headache, and fatigue."*[42]

While CBE does not dispute that Phillips 66 can buy a range of crude oils, there is also no disputing that the company explicitly plans to use the Project tanks to facilitate a significant increase in receiving, storing and processing "advantaged crude" oils, and specifically tar sands and Bakken crudes, as has been made clear repeatedly by its own representatives. It is also well known and documented on the record including the exhibits attached hereto, that heavy, high sulfur Canadian crude oils and Bakken crudes carry serious environmental and human health implications.[43] In addition to the procedural and other substantive flaws contained in the District's approval and certification of the Final Negative Declaration for the Project, the Final Negative Declaration fails to evaluate the baseline and fails to account for increased sulfur processing in the refinery due to the potential major increase in high sulfur crude oil. The Final

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[41] Contra Costa County – including Equilon refinery hydtrotreater accident, July 18, 2001, http://cchealth.org/hazmat/accident-history.php

[42] ATSDR, 2006, Division of Toxicology and Environmental Medicine ToxFAQs, http://www.atsdr.cdc.gov/tfacts114.pdf

[43] These two crudes are those which have been identified by Phillips 66 as explicitly included in the company's current definition of "advantaged" or "cost advantaged" crudes, as they are relatively less expensive than other crudes and can greatly increase Phillips 66's profit margin. While these two crude types may cause distinct impacts, both indisputably cause significant, detrimental impacts as a result of their chemical composition and blend with diluents as further described in the attached exhibits including the expert reports from Dr. Phyllis Fox, submitted for the purpose of analyzing impacts from similar projects elsewhere in the state. *See* Exhibit U, included in attached Exhibits.

Negative Declaration thereby ignores the critical need to evaluate the potential significant impacts due to increased hazardous sulfur materials in the refinery and dismisses the possibility that the refinery's current baseline sulfur content could increase. By this omission the Final Negative Declaration omits a necessary analysis of substantial evidence supporting a fair argument that the Project has the potential to cause significant environmental impacts, due to the potential to greatly increase Canadian tar sands crude oil as described above, and as further described in CBE's comments to the Draft Negative declaration. The District also appears to assume that because N. Dakota Bakken crude oil has been used at the refinery previously it was not necessary to evaluate environmental impacts caused by significant increases in the use Bakken crude oil that will be facilitated by the Project. As previously discussed, Phillips 66 specifically stated that the new tankage as for the purpose of bringing in "advantaged crude" oils. Phillips identified both Canadian crude and N. Dakota Bakken crude oil as the two advantaged crudes it is seeking to bring to the refinery. CBE provided information in the comments on the Draft ND on the problems of Bakken crude oils, which are more volatile and can increase accident risk in refineries.

Furthermore, the Department of Transportation has published safety alerts for all forms of transport of Bakken crude oil (not just rail), so the ship transport proposed in the Project is also vulnerable to this increased danger due to the volatility of this crude oil.[44] Baselines of the refinery crude oil in general are missing and an evaluation of the impacts of the increases in Bakken crude oil in transportation, and in the refinery are also missing, because the District stated there is no nexus between the company's advantaged crude plans and the new tanks. Phillips 66 statements, however, clearly warrant a full evaluation of these potential impacts.

Other characteristics of the "advantaged" crudes, or specifically the AWB crudes identified by Phillips 66 in correspondence to the Distrcit, such as its vapor pressure or flammability, may also differ in significant ways from the crudes processed in the Los Angeles Refinery's current crude slate. These other constituents and properties are not a function of the

[44] The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, January 2, 2014, http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_111F295A99DD05D9B698AE8968F7C1742DC70000/filename/1_2_14%20Rail_Safety_Alert.pdf.

API gravity or the sulfur content and are present independent of them. Thus to the extent the District relies on its responses to comments to refute the need to analyze the impacts from these new, distinctly sourced crudes, the District is incorrect.

The vapor pressure of crude determines to a large extent the amount of reactive organic compound (ROG) and Toxic Air Contaminant (TAC) emissions that are released when crude is transported, stored, and refined. Thus, a crude slate may even have identical sulfur content and weight, but would still result in dramatically different ROG and TAC emissions.[45] Similarly, the nature of the chemical bonds in crude determines the amount of energy and hydrogen that must be supplied to refine it. Thus, a crude slate may have identical sulfur and weight, but a different mix of chemicals that would affect the amount of energy and hydrogen required to convert it into refined products.[46]

These differences—in both chemical and physical characteristics other than API gravity and sulfur content— fluctuate independent of sulfur content and API gravity and will result in significant impacts that have not been considered by the District, and are absent from the District's responses to comments, and the Final Negative Declaration analyses.   Just some of these impacts include, for example, significant increases in ROG emissions, contributing to existing violations of ozone ambient air quality standards; significant increases in TAC emissions, resulting in significant health impacts in an already over-burdened local setting as described in more detail below; significant increases in malodorous sulfur compounds, resulting in significant odor impacts; significant increases in combustion emissions, contributing to existing violations of ambient air quality standards; and significant increases in flammability, thus increasing the potential for more dangerous accidents involving storage and process equipment

Moreover, as explained in response to similar project proposals, the above crude characteristics also contribute to train derailments or spills on-site.[47] And, the Final Negative

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[45] *See* Exhibit U, Dr. Fox report to Valero Crude By Rail Project EIR – Benicia.
[46] *Id*.
[47] *Id*.

Declaration and the District's responses to CBE comments fail to respond to CBE comments raising these concerns. For example, the District stated in the Final ND that a new condition will be set so that the Project tanks will not receive crude oil brought in by rail. Because the project tanks represent an extremely large new source of crude oil storage and throughput (over 50 million barrels per year in throughput), this condition does preclude the Project from having a significant potential to allow an increase in transport by rail. Indeed, the extent of increase in the overall throughput capacity involved in the project, appears to show that the Project will free up other existing storage tank space in the refinery. Since the refinery is not taking a permit requirement that precludes crude by rail offloading to *all* refinery tanks, the Project also has the potential to also allow an increase in crude offloading by rail in other parts of the refinery, in addition to the crude offloading by ship to these Project tanks. Consequently, the potential impacts from rail still need to be evaluated.

3. The District's decision to approve and certify the Negative Declaration ignores cumulative impacts from other projects and environmental justice concerns.

Currently there are 3 refinery projects being proposed in Wilmington and the adjacent City of Carson, as well as additional project-related permit applications at various stages of review by the District. All 3 projects directly impact many of CBE's members and other residents living *directly on the fenceline* of the refineries at which they are being proposed.

These 3 projects include:

1) The Project at issue in this appeal;

2) The Phillips 66 Wilmington Ultra Low Sulfur Diesel Project, for which the District issued a Draft EIR on September 26, 2014; and

3) The Tesoro-BP Refinery Integration Project, for which the District issued a Notice of Preparation of a Draft Environmental Impact Report on September 9, 2014 (and for which the District is also reviewing two Title V permit revisions and renewals--for the Tesoro Marine Terminal 2 and the Tesoro Hynes Terminal in Long Beach).

Wilmington and the cities of Carson and Long Beach rank among the State's top most pollution-burdened and vulnerable areas.[48] Residents of these communities live with the day-to-day impacts of various forms of heavy industry, oil extraction and refining operations, port and other goods-movement and transport activities, including significant levels of air pollution caused by diesel truck and railroad transport.[49] As such, these residents rely heavily on the oversight of agencies like the District to ensure that permitting and project approval decisions regarding additional, highly polluting industrial projects are made wisely, with careful attention to the true range of environmental and health impacts resulting from each individual project alone, and in the context of existing cumulatively considerable burdens.[50]

Despite the existing burden on this area, the District is conducting an impermissibly superficial level of environmental review for projects directly impacting some of the region's most vulnerable neighborhoods. While this problem is in large part a result of inaccurate and often misleading project descriptions contained in the applications submitted by refinery operators, the District is responsible for ensuring that CEQA and other air quality and human health protective requirements are met before it moves forward in issuing or approving any permits or other project-related approvals, including approvals of environmental review documents and permit renewals or revisions.[51]

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[48] Wilmington, Carson and parts of Long Beach 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. (*See* http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?&extent={"xmin":-13166567.802417224,"ymin":4001409.3038827637,"xmax":13157213.82108084,"ymax":4005584.676552836,"spatialReference":{"wkid":102100}}&appid=a4a95185c71f4817bf03aeae25923695 (last accessed, Dec. 23, 2014).

[49] *See Id*.

[50] *See, Laurel Heights Improvement Assn. v. Regents of Univ. of California* (1988) 47 Cal.3d 376, at 394 (holding that the significant cumulative effects of a project must be considered in an EIR, and specifying that such required cumulative effects should encompass "past, present, and reasonably anticipated future projects.); *see also*, CEQA Guidelines, § 15064 (h)(1) (also requiring preparation of an EIR, where cumulative impacts are considerable, and providing that "[w]hen assessing whether a cumulative effect requires an EIR, the lead agency shall consider whether the cumulative impact is significant and … An EIR must be prepared if [a] Project's incremental effect, though individually limited, is cumulatively considerable[,]" meaning that "incremental effects of an individual project are significant when viewed in connection with the effects of past projects … other current projects, and … probable future projects"), and §15355 ("'Cumulative impacts' refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts"); *see also*, Clean Air Act, Declaration of Purpose, at 42 U.S.C. § 7401(b)(1)-(3), (c)(providing that the purpose of the Act is to enhance the quality of the Nation's air resources so as to promote the public health and welfare; and to encourage and assist the development and operation of regional air pollution prevention and control programs to do the same.).

[51] *See* Cal. Pub. Res Code § 21082.2(a) (requiring the lead agency to determine whether a project may have a significant effect on the environment based on substantial evidence in light of the whole record.); *see also Citizens*

4. The District has no process for appealing a staff's decision on a negative declaration.

Counsel for CBE has extensively reviewed the District Rules, website and other materials. There are no procedures for appealing staff decisions on CEQA documents for projects where the District is the lead agency. Also, the Final Negative Declaration included no procedures for appealing the decision. Given the vital import of this project and the information provided on the processing of more dangerous crude oil at this facility, the public and the Governing Board members must have a robust review process. Accordingly, the District should withdrawl its staff approval, adopt a procedure for processing appeals of this sort through an official process, and then process this appeal according to these duly adopted protocols. If the District decides to process the appeal in an ad hoc manner, we respectfully request that CBE be provided at least 30 minutes to present to the Governing Board. Moreover, the public should be provided the opportunity to comment on this item at a duly noticed Governing Board meeting.

Assoc. For Sensible Development of Bishop Area v. County of Inyo (1985) 172 Cal.App.3d 151("The lead agency must consider the whole of an action, not simply its constituent parts, when determining whether it will have a significant environmental effect."); and *see* CEQA Guidelines § 5041(setting forth the Lead Agency's Authority to mitigate negative environmental impacts, and providing that "A lead agency for a project has authority to require feasible changes in any or all activities involved in the project in order to substantially lessen or avoid significant effects on the Environment.").

III. CONCLUSION

For these reasons, and for the additional reasons expressed in CBE's comments on the above listed projects, as well as the additional, attached correspondence and exhibits we appeal the District's certification of the Negative Declaration and we urgently request that Governing Board take immediate steps to withdraw the December 12, 2014 Notice of Determination, approval and certification of the Final Negative Declaration for the Phillips 66 Carson Project.

Dated: January 9, 2015

Respectfully submitted,

/ s

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Attorneys for Petitioner
COMMUNITIES FOR A BETTER ENVIRONMENT

List of Exhibits in Support of CBE Appeal of SCAQMD Dec. 12, 2014 Notice of Determination for the Phillips 66 Carson Crude Oil Storage Capacity Project – SCH No. 2103091029

**Please note that exhibits I and P have been stricken as duplicative, and exhibit X has been added from the previous list submitted to the Board Clerk; the Declaration accompanies CBE's appeal.*

Exhibit A	1_2_14 Rail_Safety_Alert Bakken Crude
Exhibit B	Chevron Richmond Refinery Modernization Appendix_3_overview of refineries
Exhibit C	Major Accidents at Chemical and Refinery Plants Contra Costa County Report.
Exhibit D	Norwegian Science and Tech on Sour Crude processing problems
Exhibit E	H2S tfacts114 ATSDR
Exhibit F	CEC-600-2006-006 California Crude Oil Production and Imports
Exhibit G	Alaska North Slope Crude production graph USEIA
Exhibit H	AWB Crude CrudeMonitor.ca - Canada
~~*Exhibit I~~	~~P66 Transcript Q3 2014 10292014 Conference Call Earnings and plans~~
Exhibit J	Q32014InvestorUpdatePSX P66
Exhibit K	After the Oil Rush – ANS. Report
Exhibit L	2014-fact-book_v001_e5w4rc P66
Exhibit M	Application Crude Storage Tank Project docs - Carson Facility
Exhibit N	Letter to Los Angeles City Council and SCAQMD Board member Joe Buscaino and Dr. Wallerstein, January 2013
Exhibit O	SCAQMD Crude Quality – Health Letter, April 2013
~~*Exhibit P~~	~~Crude Storage Tank Project Permit Documents~~
Exhibit Q	2014-dec5-SCAQMD Board Meeting Agenda
Exhibit R	SCAQMD Crude Quality – Health Letter
Exhibit S	JMay CBE Comments Tesoro storage tank ND final
Exhibit T	Karras Exp Rpt Rodeo (LP12–2073)
Exhibit U	Dr. Fox Comments to Valero Crude By Rail Project, Benicia, September 9, 2014
Exhibit V	Dr. Fox Comments to Revised DEIR for the Phillips 66 Rail Spur Extension and Crude Unloading Rack Project 11-24-14
Exhibit W	CBE Comment to Revised DEIR for Phillips 66 Rail Spur Extension and Crude Unloading Rack Project
*Exhibit X	Julia E May Declaration in Support of CBE's Appeal of the SCAQMD's Notice of Determination, approval and certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project, Jan. 9, 2015

The Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue, SE
Washington, DC 20590
www.phmsa.dot.gov

Safety Alert -- January 2, 2014

Preliminary Guidance from OPERATION CLASSIFICATION

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

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

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

As part of ongoing investigative efforts, PHMSA and FRA initiated "Operation Classification," a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have been properly classified and describe the hazardous materials. Preliminary testing has focused on the classification and packing group assignments that have been selected and certified by offerors of crude oil. These tests measure some of the inherent chemical properties of the crude oil collected. Nonetheless, the agencies have found it necessary to expand the scope of their testing to measure other factors that would affect the proper characterization and classification of the materials. PHMSA expects to have final test results in the near future for the gas content, corrosivity, toxicity, flammability and certain other characteristics of the Bakken crude oil, which should more clearly inform the proper characterization of the material.

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

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

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

APPENDIX 3

Overview of Oil Refining Process

APPENDIX 3
OVERVIEW OF OIL REFINING PROCESS

This appendix provides a high-level, non-project specific description of the refining process as it generally occurs at the Chevron Richmond Refinery (Facility or Project site).

The refining process begins when *crude oils* or *externally sourced (purchased) gas oils* are delivered to the Facility as raw materials or feedstocks. These feedstocks are then refined in five main process steps:[1]

- *Distillation* occurs when crude oil is separated by "distilling" into various components, called "crude oil fractions;"
- *Treatment* occurs when crude oil fractions are "treated" to remove sulfur and other natural impurities;
- *Cracking* occurs when molecules in the heavier crude oil fractions are divided by *cracking* these larger molecules into smaller molecular forms that can become transportation petroleum products;
- *Reshaping* (also called "reforming") occurs when these molecules are "shaped" to meet the specifications for various kinds of products (e.g., octane levels in gasoline); and
- *Blending* occurs in the final product production process, when multiple hydrocarbon fractions are blended to meet the specifications for particular products (e.g., higher octane versus lower octane gasolines). *Blending* occurs

[1] While these five major steps in the refining process are described as discrete steps, not all hydrocarbon molecules in the refining process go through each of these steps, and some of these refining process steps are actually repeated in later refining steps. For example, the first step in the process, *Distillation*, describes the process of applying heat to crude oil to separate it into "fractions," or separate streams of hydrocarbon molecules that boil at different temperature ranges. The fractions are then piped on to different refinery processing steps to produce different products. While the major distillation process occurs as the first step in the refining process at the crude unit (described in the *Distillation* step below), smaller distillation units also operate at several later stages in the refinery process. For example, the hydrotreating process (described in the *Treatment* step below) results in some cracking (described in the *Cracking* step below), and the cracked hydrocarbon output then is run through a fractionator (a type of distillation unit) to again separate this output into fractions as needed for the next processing steps.

when different products are piped into tanks and typically does not involve mechanical mixing.

The refining process as a whole is depicted in Figure A3-1, *Facility Process Diagram*. A description of the feedstocks processed by the Facility is provided below, followed by a description of each of these major processes.

3.1 FEEDSTOCKS

Crude oil is the Facility's primary "feedstock," which is the raw material used to make refined petroleum products. A partially refined crude oil fraction called "gas oil" is also received by the Facility and is purchased from external sources (i.e., other refineries). Crude oil and gas oil are described below.

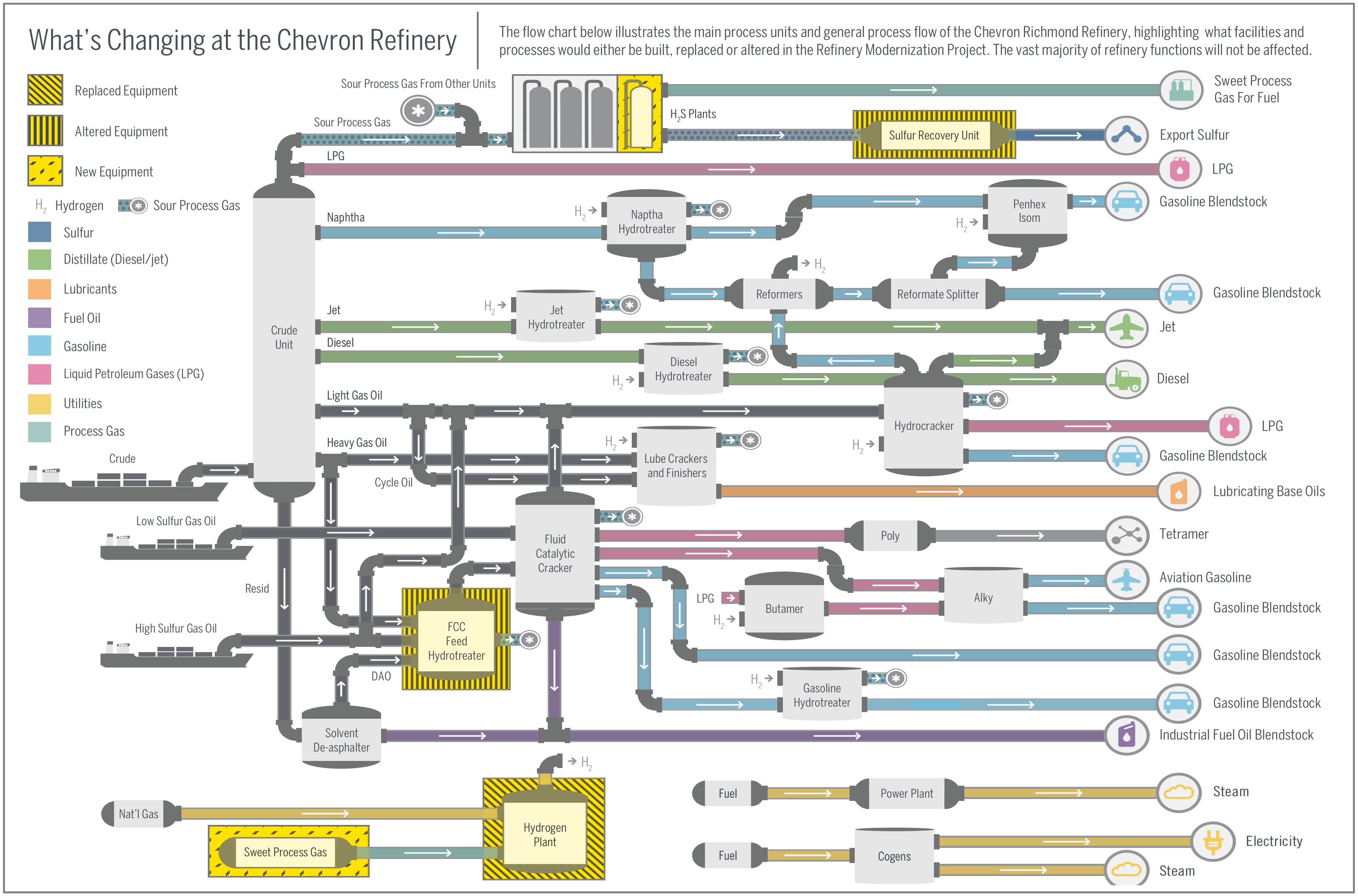
3.2 IMPORTANT CHARACTERISTICS OF CRUDE OIL

Crude oil is found deep beneath the earth's surface in natural underground reservoirs. Crude oil is believed to have been formed from a mixture of mud and very small plants and animals (algae and zooplankton) that lived in ancient seas and oceans millions of years ago. Crude oil was created from this mix through a combination of temperature, pressure, and time.

Crude oil is recovered primarily from oil extraction wells, and it is often temporarily stored near extraction areas before being transported (primarily by pipelines and ships) to refineries for processing. Unlike many other refineries in the United States, the Facility is not connected to crude oil supplies through pipelines. Instead, the Facility receives crude oil via tankers and barges that discharge at the Project site over the Long Wharf. Crude oil is stored in tanks at the Project site before being processed in the Facility.

Crude oil is not a single chemical compound. Instead, crude oil is a mixture of different chemical compounds, the vast majority of which include a combination of hydrogen and carbon atoms, and are thus called "hydrocarbons." Other atoms, including nitrogen and sulfur atoms, can also be part of hydrocarbon molecules. Crude oil hydrocarbons may also contain small amounts of metals. Crude oil also typically includes small amounts of non-hydrocarbon contaminants, such as sediment, salt, and water.

The different hydrocarbon compounds in crude oil have different boiling points (the temperature at which liquids "boil"). Heating crude oil and condensing the heated vapors causes it to be physically separated into different streams of hydrocarbons (called "fractions") through a simple distillation process (described further below).



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Source: Chevron (T39r2)

Figure A3-1
Chevron Refinery Modernization Project EIR
Facility Process Diagram

One of the hydrocarbon fractions produced in the Facility's refining process is "gas oil," which is produced during the distillation process and various other processes. In addition to producing gas oil from crude oil feedstocks, Chevron imports surplus gas oil from other refineries. The Facility imports gas oil because it contains equipment that can refine more gas oil than what can be produced economically from its crude oil feedstock. In other words, the crude unit, the solvent de-asphalting unit (SDA unit, described below), and other process units that produce gas oil produce a smaller amount than later steps in the refinery processes can refine due to that equipment's greater capacity. Because a refinery's "efficiency" (also discussed in greater detail below) is directly linked to maximizing utilization of refinery equipment, Chevron imports purchased gas oil to efficiently utilize available Facility capacity.

3.2.1 Density or "Gravity" of Crude

"Density" is the amount of mass contained in a certain volume. The density of a crude oil is determined by the average weight (or "gravity") of its component molecules. "Heavy" crude oil is denser than "light" crude oil because the hydrocarbon molecules in heavy crude oil are larger and have more carbon atoms than those in light crude oil.[2] Atoms in a larger molecule are tightly bound together and take up less space than the same number of atoms spread out across multiple smaller molecules. Thus the atoms in heavy crude oil are more tightly packed together, taking up less space (volume) and making heavy crude oil denser than light crude oil.

Less dense (or "light") crudes generally have more light hydrocarbons, and light hydrocarbons are the constituents of higher-value refinery products such as gasoline, jet fuel, and diesel. Similarly, the denser ("heavier") crudes generally contain more of lower-value products like gas oil, tar, and bunker fuel commonly used in shipping.

When a refinery processes light crudes, higher-value products can be produced in fewer steps. For example, a light crude may only need to be "distilled" (the first step in the refinery process, described below) to produce large amounts of gasoline *blendstocks*. In contrast, a heavy crude may need to go through all of the refinery processes explained below (*Distillation*, *Treatment*, *Cracking*, and

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[2] Heavy crude oil can also be denser than light crude oil because a higher proportion of the hydrocarbon molecules are in a denser form. (This characteristic is identified by the percentage of naphthenes in the crude.) Hydrocarbon molecules that are highly naphthenic can have molecules with the same number of carbon atoms, but those atoms are shaped like a circle rather than a straight chain. The circular structure is more dense than the straight chains.

Reshaping) to produce the same amount of gasoline or other light products. It should be noted that the *very* light hydrocarbons, at the other end of the gravity range, also have limited value. The ultimate light hydrocarbon is methane gas (CH_4), which is the primary component of natural gas. It can be quite a bit less valuable than even crude oil because natural gas is generally widely available. Therefore, the price paid for a "condensate" (a very light combination of hydrocarbons), can be less than a crude oil with significant mid-range hydrocarbon molecules.

The density or gravity of crude oil is important to the refining process in several ways. As mentioned above, when the mixture of compounds in crude oil is heated, lighter hydrocarbon compounds will begin to vaporize (turn into gas), and heavier compounds will not. As the temperature within this initial crude processing step is increased, heavier hydrocarbons will begin to vaporize.[3] This physical characteristic of crude oil is key to the first step in the refining process: *Distillation*, in which crude oil (which has been desalted as described below) is heated in a furnace and sent to a large steel column to separate out the different hydrocarbons.

Different hydrocarbons boil at different temperature ranges and are grouped together in "fractions" based on these temperature ranges. The typical boiling temperatures of different fractions are shown in Figure A3-2, *Typical Boiling Temperatures (Cut Points) for Different Hydrocarbon Fractions*. Larger molecules contain more carbon atoms, are generally denser, and have a higher boiling point. Conversely, compounds with a lower carbon count are less dense and boil at a lower temperature.

For example, "gas oil" is the term used to describe the fraction of crude oil that is heavier than common refined products like gasoline, diesel, and kerosene or jet fuels—but lighter (less dense) than the heaviest fractions, which are called "residue" or "residuum." Petroleum scientists devised a unique name for measuring the density, or weight, of a given hydrocarbon compound, called "American Petroleum Institute (API) gravity." API gravity describes the density of a crude oil compared to the density of water. The lower the API gravity, the heavier the crude.[4] The API gravity can be used to categorize crude as "heavy, intermediate, or light" as discussed in Section 4.0.3 of the *Chapter 4, Introduction to Chapter and Methodology*. Definitions for "light" and "heavy" crude oils are based

[3] This is different from water—a single chemical compound of two hydrogen atoms and one oxygen atom, or H_2O—which would eventually all boil away into steam at the constant temperature of 212°F at normal pressures.

[4] For comparison, water has an API gravity of 10 degrees. Generally, hydrocarbons with an API gravity above 10 degrees are lighter than water and will float.

on their specific gravity[5] or API gravity.[6] The following are generally accepted definitions for the crude oil gravities (CEC, 2006):

- **Heavy Crude.** Crude oils with API gravity of 18 degrees or less are characterized as heavy. The oil is viscous and resistant to flow, and tends to have a lower proportion of volatile components.
- **Intermediate Crude.** Crude oils with an API greater than 18 and less than 36 degrees are referred to as intermediate.
- **Light Crude.** Crude oils with an API gravity of 36 degrees or greater are referred to as light. Light crude oil produces a higher percentage of lighter, higher-priced premium products.[7]

3.2.2 Sulfur Content in Crude Oil

Another important natural characteristic of crude oil is that different types of crude oil have differing amounts of sulfur content. Sulfur occurs naturally in crude oil, but sulfur content is restricted by federal and State air quality laws in refined products (e.g., there are standards limiting the amount of sulfur that can be present in refined products like gasoline). To meet these regulatory restrictions on sulfur content in refined products, sulfur is removed from the various fractions of crude oil during the refining process.

When an oil has less sulfur, it is referred to as being "sweet." Crudes with more sulfur are referred to as being "sour." Although there is no regulatory threshold of sulfur content for dividing sweet crude oils from sour crude oils, oils with less than 0.5% sulfur content are generally referred to as "sweet."

Most sulfur present in crude oil is bonded within hydrocarbon molecules, although some is present as hydrogen sulfide (H_2S) gas . This is different from "elemental" or pure sulfur (a yellow crystalline substance when at room temperature), which is a usable product. During the refining process, the sulfur atom is removed from the hydrocarbon molecule. This process is called

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[5] The specific gravity equals the weight of the compound divided by weight of an equal volume of water.

[6] The API gravity, measured in degrees (°), is defined as equal to (141.5 divided by specific gravity)—131.5. As a result, the higher the API gravity, the lighter the compound. Note that water has an API gravity of 10°, so any hydrocarbon crude with an API gravity greater than 10° is less-dense (lighter) than water.

[7] These API breakpoint values are not applied universally. Other petroleum industry sources use varying breakpoints for heavy and light crude oils. The term "intermediate" is also used interchangeably with the term "medium" when referring to mid-range gravity crudes.

"hydrotreating" because it includes the use of hydrogen. The hydrocarbon fractions are combined with hydrogen in the presence of a catalyst and elevated temperatures and pressures. The catalyst, temperature, and pressure separate the sulfur from the hydrocarbon molecule and the sulfur combines with the available hydrogen to produce a gas called hydrogen sulfide (H_2S). This hydrogen sulfide gas is then treated, as explained below, to create "elemental" sulfur, which is sold as a product by Chevron. The Modernization Project includes several components to allow Chevron to remove more sulfur from the Facility's feedstocks and thereby refine higher sulfur crude oil and gas oil in the future.

3.3 CUTTER AND BLENDSTOCKS

In addition to feedstocks imported by the Facility for processing into transportation fuels and base oils, the Facility imports a small amount of blendstocks to be used in making final products that leave the Facility. The Facility imports two main types of blendstocks, a fuel oil blendstock called "cutter" and light product blendstocks, both of which are imported over the Long Wharf. Once on-site, blendstocks are not processed by the Facility, but rather serve as one of the components when mixing other Facility-produced blendstocks into finished products.

Cutter is used by the Facility to lower the viscosity of fuel oil product. The Facility has several process units that create material that can be used as cutter (e.g., cycle oil) and the Facility can always produce sufficient quantities to meet the Facility's overall cutter demand. As a result, cutter import is unrelated to refinery utilization. Nevertheless, there are times, such as when another facility has a surplus of cutter, in which the Facility may import material from other facilities (including other Chevron facilities) to be used as cutter instead of using internal sources.

Similarly, light product blendstocks can be imported, dependent on market conditions, into the Facility to supplement the various blendstocks or products that are produced by the Facility process units. These blendstocks (e.g., iso-octane) are used in the blending of finished products such as gasoline, but again are not used as feed to the Facility process units.

3.4 OVERVIEW OF THE REFINING PROCESS

3.4.1 Distillation: Separating the Fractions of Crude Oil with Heat

3.4.1.1 Crude Oil is First Pre-Heated and Treated to Remove Contaminants

Before crude oil goes through the first major step of the refining process, *Distillation,* it is preheated and treated to remove contaminants. First, the crude oil is delivered on ships, pumped into holding tanks, and then pumped from those tanks to the crude unit. En route, the crude oil is heated in a series of "heat exchangers," where heat from steam or already-heated product is transferred to the incoming cooler crude oil feedstock. (See below for a description of heat exchangers.)

Crude oil typically contains a small percentage of water and salts dissolved in the water. Because the salts are considered contaminants, after the pre-heating process the heated crude oil is next sent to a "desalter," where these contaminants are removed. This protects the downstream equipment from potential plugging and corrosion mechanisms that can be associated with salts in crude oils.

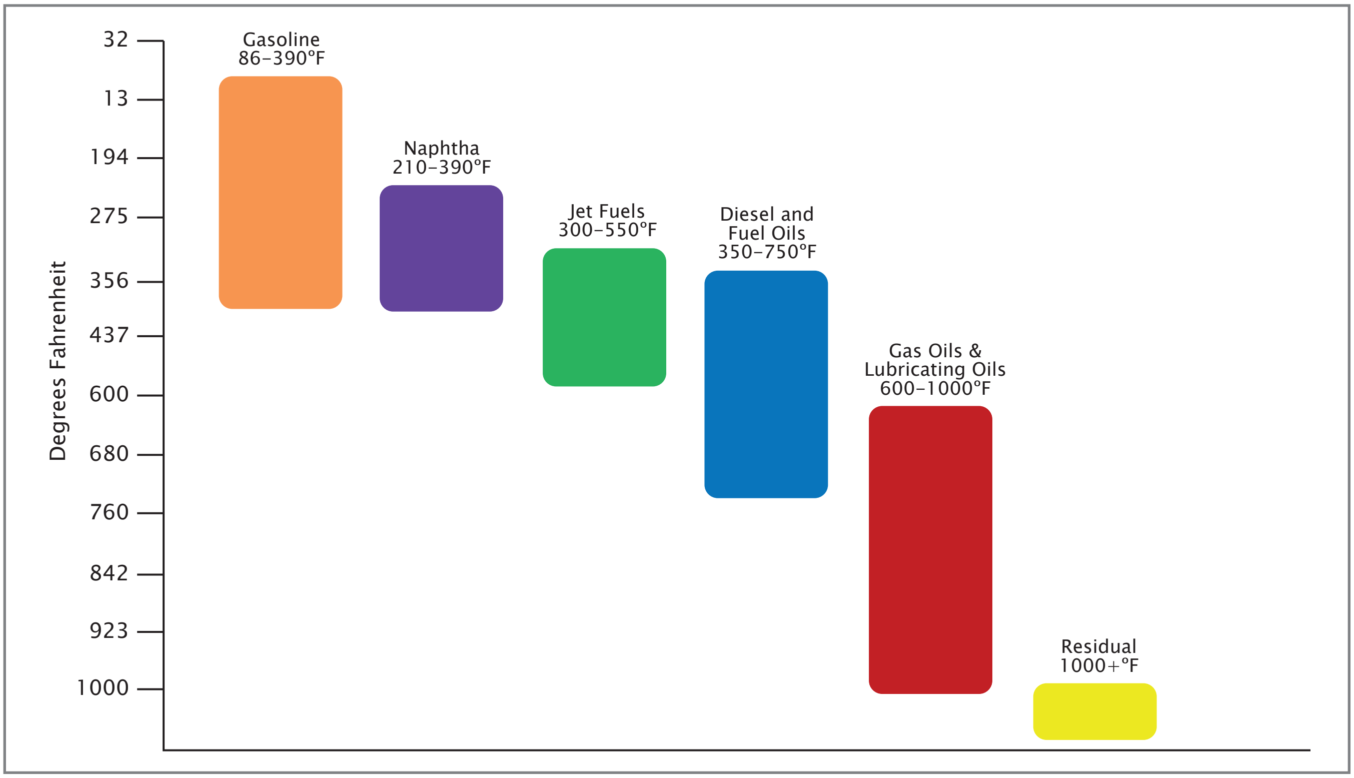
A desalter is a large cylindrical vessel laid horizontally. The desalter removes contaminants from crude oil by first emulsifying (mixing together) the crude oil with wash water to promote thorough contact of the water and oil. The salts dissolve in this water phase. After the oil has been washed and mixed as an emulsion of oil and water, electrostatic fields are used to break the emulsion, separating the crude oil and water again (Johnson, 2014). The mixture of contaminants and water that has been separated from the crude oil is pumped into a wastewater treatment plant as described below.

Next, the crude oil is further pre-heated in heat exchangers and charged to a pre-flash tower. Light ends are flashed off (rapidly heated), and bypass the furnace. By pre-heating the feedstock and flashing off light ends, the process unit furnaces do not have to work as hard to heat the feedstock, saving energy. The remaining crude oil passes through a furnace where it is heated to a temperature of approximately 700°F. At this temperature, typically about half of the crude oil changes from liquid to vapor (see *Figure A3-3, Flow Diagram from Wharf to Crude Unit*). This combination of liquid and vapor is then ready for *Distillation*, the first major step in the refining process, described below.

3.4.1.2 The Primary Distillation Process Occurs in the Crude Unit

Distillation is the process of using heat to separate crude oil into different hydrocarbon streams by boiling point (called "cut points"). These separated "fractions" of crude oil are sent on to different parts of the Facility for further processing. Crude oil *distillation* occurs in the Facility's crude unit. The lighter compounds such as butane, gasoline, jet fuel, and diesel "boil off" (vaporize) at lower temperatures, and as the temperature increases, the heavier compounds such as gas oil vaporize last. The material that does not vaporize is referred to as "residuum."

A typical distillation schematic in Figure A3-4, *Distillation Schematic*, shows the separation of crude oil into fractions, from lighter at the top to heavier at the bottom. Figure A3-5, *Distillation Curve,* provides a typical distillation curve,



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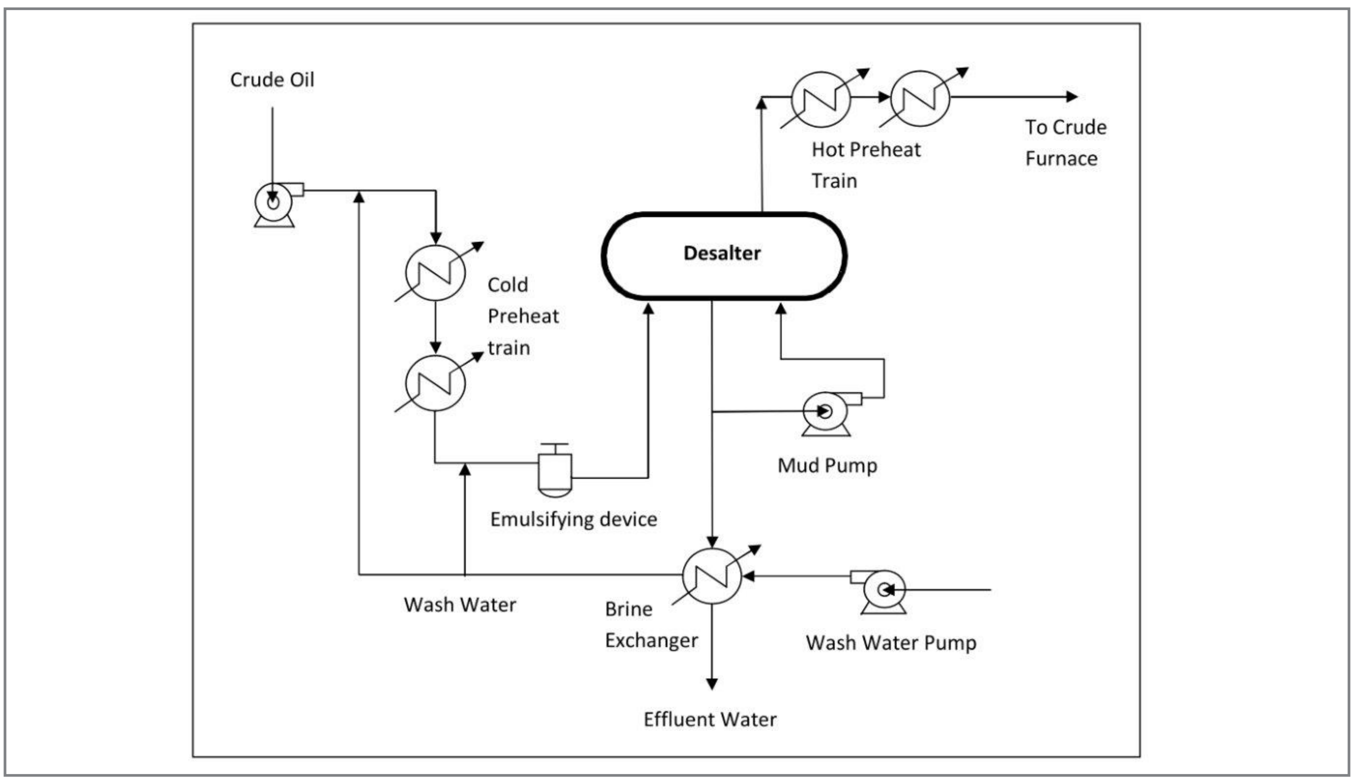
Source: Turner, Mason & Company, 2011

Figure A3-2
Chevron Refinery Modernization Project EIR
Typical Boiling Temperatures (Cut Points) for Different Hydrocarbon Fractions



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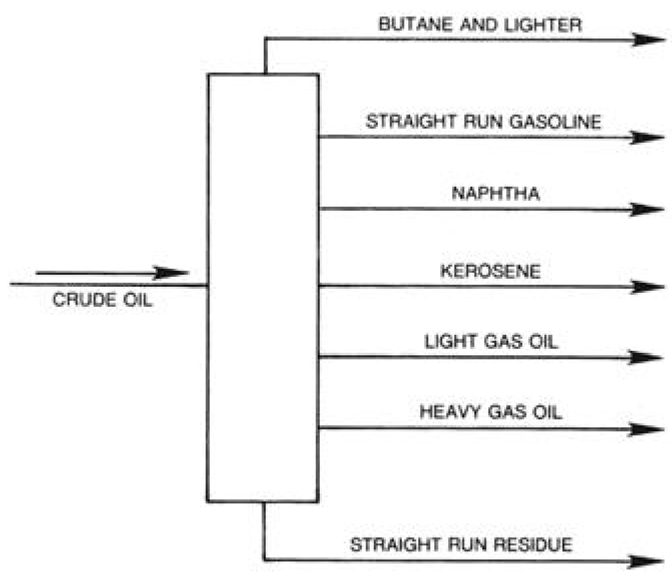
Source: Enggcyclopedia, 2014

Figure A3-3
Chevron Refinery Modernization Project EIR
Typical Flow Diagram from Wharf to Crude Unit (Including Desalter, Heat Exchangers, Pipes)



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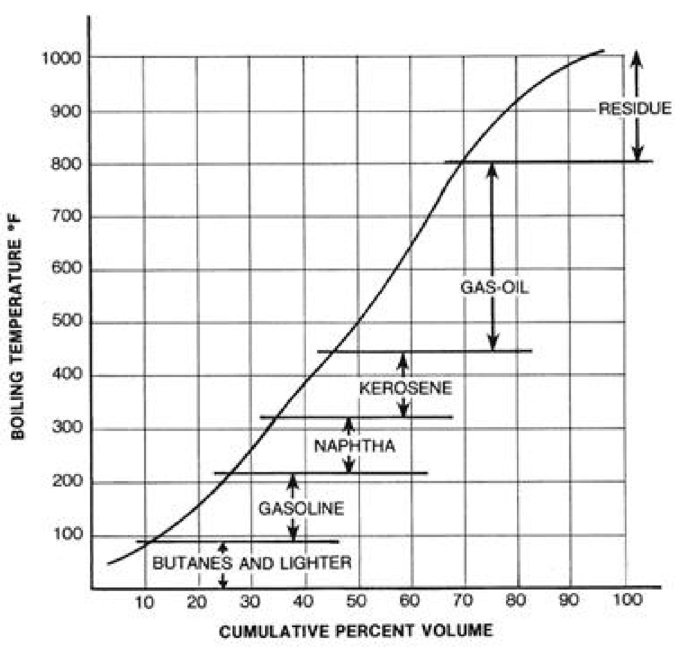
Source: Petroleum Refining in Nontechnical Language, 2008

Figure A3-4
Chevron Refinery Modernization Project EIR
Distillation Schematic



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Source: Petroleum Refining in Nontechnical Language, 2008

Figure A3-5
Chevron Refinery Modernization Project EIR
Distillation Curve

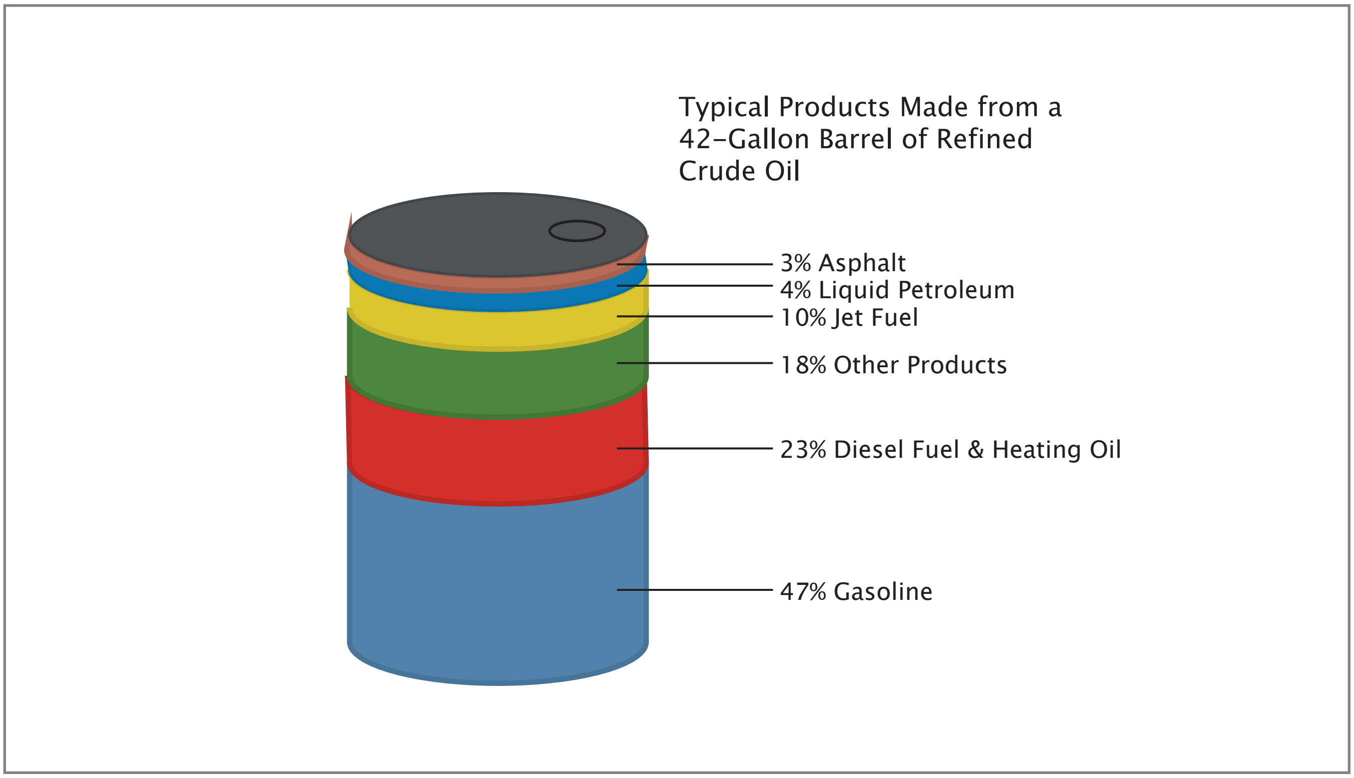
showing volume and boiling temperatures (or "cut points") for the various fractions of crude oil.

Crude oil fractions in the higher boiling point range require more complex equipment to process into transportation fuels and base oils that are in highest demand in the market. Crude oil fractions with lower boiling points still require further processing to meet finished product specifications, but typically require less complex refining. Figure A3-6, *Breakdown of a Typical Crude Oil Distillation Yield*, shows a typical breakdown of the composition of a barrel of crude oil according to the United States Energy Information Administration (EIA). Although this distillation process separates significant quantities of the lower boiling point fractions such as gasoline, by further refining the higher boiling point fractions, such as gas oils, more of the crude oil can be converted to desirable transportation fuels and base oils.

The crude unit is comprised of several pieces of equipment, as depicted in Figure A3-7, *Crude Unit Overview,* each of which is discussed below. The first distillation column in the crude unit at the Facility is the "atmospheric distillation column," which is named "atmospheric" because the pressure in the unit is similar to the outside atmosphere. It operates on the physical principle of temperature to separate different hydrocarbon fractions and send them to different parts of the Facility for further processing. This is possible because, as discussed above, the different groups of hydrocarbon compounds or "fractions" found in crude oil have different boiling points.

Within the column, the vaporized hydrocarbons rise and the liquid hydrocarbons fall in a column consisting of perforated trays located at 24- to 30-inch intervals. The vapors rise through the perforations in the trays and bubble up through the liquids. As the vapors bubble up through the trays of liquid, some of the heavier (denser) hydrocarbons in the vapor condense (turn back into liquid) and collect on the trays. At several levels on the column, there are "side cuts" that drain liquid forms of hydrocarbons – with lighter products drawn off from the upper parts of the column and heavier liquids drawn from the trays closer to the bottom. Figure A3-8 below, *Distillation Column: Crude Oil Separation by Heat into Fractions* shows a typical separation of crude oil into these fractions, along with general boiling points of these fractions. Each fraction is then sent to different areas of the Facility for further processing.

As shown in the distillation curve in Figure A3-5 above, not all of the hydrocarbon fractions would have vaporized even at the highest temperatures reached in the atmospheric distillation column.



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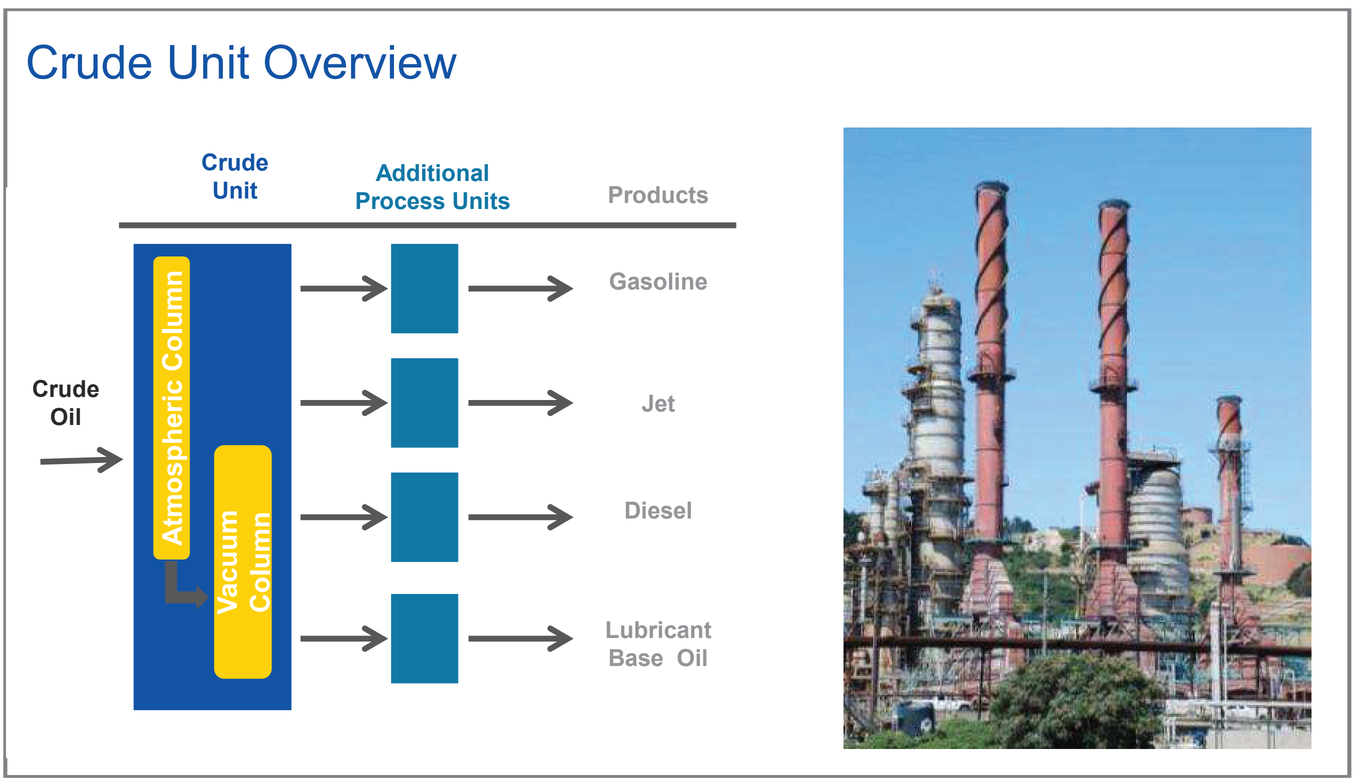
Source: U.S. Department of Energy, 2014

Figure A3-6
Chevron Refinery Modernization Project EIR
Breakdown of a Typical Crude Oil Distillation Yield



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Source: Chevron, 2012

Figure A3-7
Chevron Refinery Modernization Project EIR
Distillation Column: Crude Oil Separation by Heat into Fractions

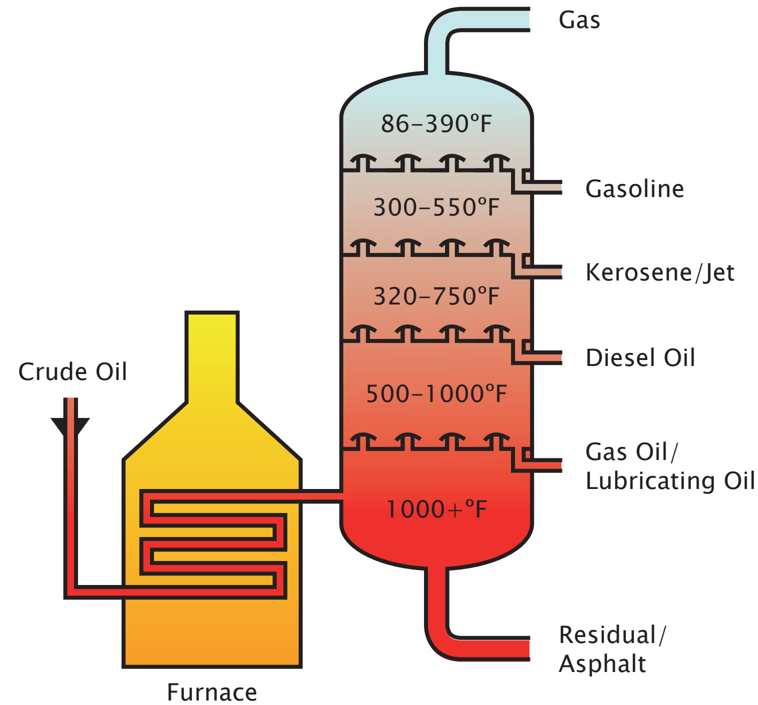
A different process, called "vacuum distillation," is used to help distill these heavier fractions by creating a vacuum condition, which is a pressure below atmospheric pressure. This decreased pressure allows the heavier fractions to boil at lower temperatures (just like water boils at a lower temperature in "thin air" that can be found at high mountain elevations) and be converted to vapor and separated.

At the Facility, this vacuum distillation process for separating the heaviest crude fractions is handled at a second distillation column, called the vacuum distillation column (see Figure A3-9, *Vacuum Distillation Process*), which is also part of the crude unit. The vacuum column construction is slightly different from the atmospheric column to minimize pressure loss in the column. The column includes several sections filled with "packing" material, sheets of metal or ceramic rings to allow the gas and liquid in the column to contact each other. There are trays in the column where light and heavy vacuum gas oil are drawn off. The bottoms from the column are residuum and are fed to the SDA unit (described below) to further separate the gas oil from the residuum.

The heaviest fraction from the vacuum distillation column, the residuum, goes through one more *separation* step before moving on to other processes. To remove the remaining gas oil from the residuum, the Facility uses an SDA unit. The SDA unit uses solvent to chemically dissolve the remaining gas oil molecules in the residuum. The gas oil and solvent mixture is sent to a column that operates at lower pressure. At the lower pressure, the gas oil separates from the solvent. The solvent is reused and the gas oil molecules are sent for further processing in the Facility's fluid catalytic cracker feed hydrotreater (FCC FHT) and fluid catalytic cracker unit (described below). The portion that is not absorbed by the solvent leaves the SDA unit as heavy residuum and leaves the Facility as a fuel oil blendstock product. The solvent is recycled back to the SDA process, where it is reused.

3.4.2 Treatment: Removing Sulfur and Other Natural Impurities

Hydrocarbons separated in the crude unit distillation process and SDA unit contain naturally occurring sulfur and other natural impurities such as nitrogen and metals. One of the key later steps in the refinery process involves chemical reaction processes that include a "catalyst" – a material that promotes or speeds up chemical reactions to produce either a finished product or another interim material to be processed further, such as in the *Cracking* step. These impurities can interfere with the *cracking* processes. In addition, they also reduce the quality and performance of finished transportation products and without sufficient removal may not comply with finished fuel regulatory standards such as Ultra Low Sulfur Diesel and California's stringent "clean fuel" gasoline standards.



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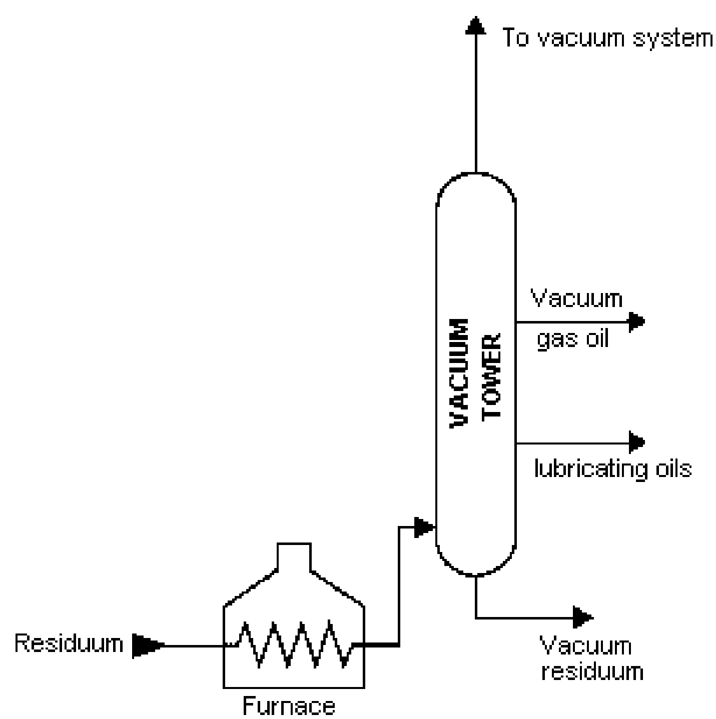
Source: Turner, Mason & Company, 2011

Figure A3-8
Chevron Refinery Modernization Project EIR
Distillation Column: Crude Oil Separation by Heat into Fractions



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Source: Set Laboratories, Inc., 2014

Figure A3-9
Chevron Refinery Modernization Project EIR
Vacuum Distillation Process

The purpose of the *Treatment* step is to largely remove non-hydrocarbon components like sulfur, metals, and nitrogen. *Treatment* primarily occurs when the separated hydrocarbon fractions are sent to "hydrotreaters." The Facility currently operates five hydrotreaters. Each hydrotreater processes different fractions of the crude oil. The diesel hydrotreater (DHT) treats diesel from the crude unit, the jet hydrotreater (JHT) treats jet fuel from the crude unit, and the gasoline hydrotreater (GHT) treats a gasoline product from the fluid catalytic cracker unit, a unit described in *Section 3.4.8* below. These three hydrotreaters—the GHT, DHT, and JHT—are "finishing" units that produce material used in fuel blending for finished products (see *Section 3.4.12* below).

The other two hydrotreaters, the naphtha hydrotreater and the fluid catalytic cracker feed hydrotreater (FCC FHT), primarily function as pre-treaters for petroleum fractions to be used as feeds to other units at the Facility for further processing before turning into finished products. The naphtha hydrotreater treats naphtha, a lighter-end fraction of crude oil distilled and routed from the crude unit to the naphtha hydrotreater. The FCC FHT treats gas oil from the crude unit and gas oil that is purchased from other refineries. The FCC FHT is labeled "FCC feed hydrotreater" because the gas oil it treats is primarily fed into the next unit in the process, called the fluid catalytic cracker, or FCC unit, which is involved in another step in the process, described below in *Section 3.4.8*. See hydrotreaters labeled in Figure A3-1, *Facility Process Diagram.*

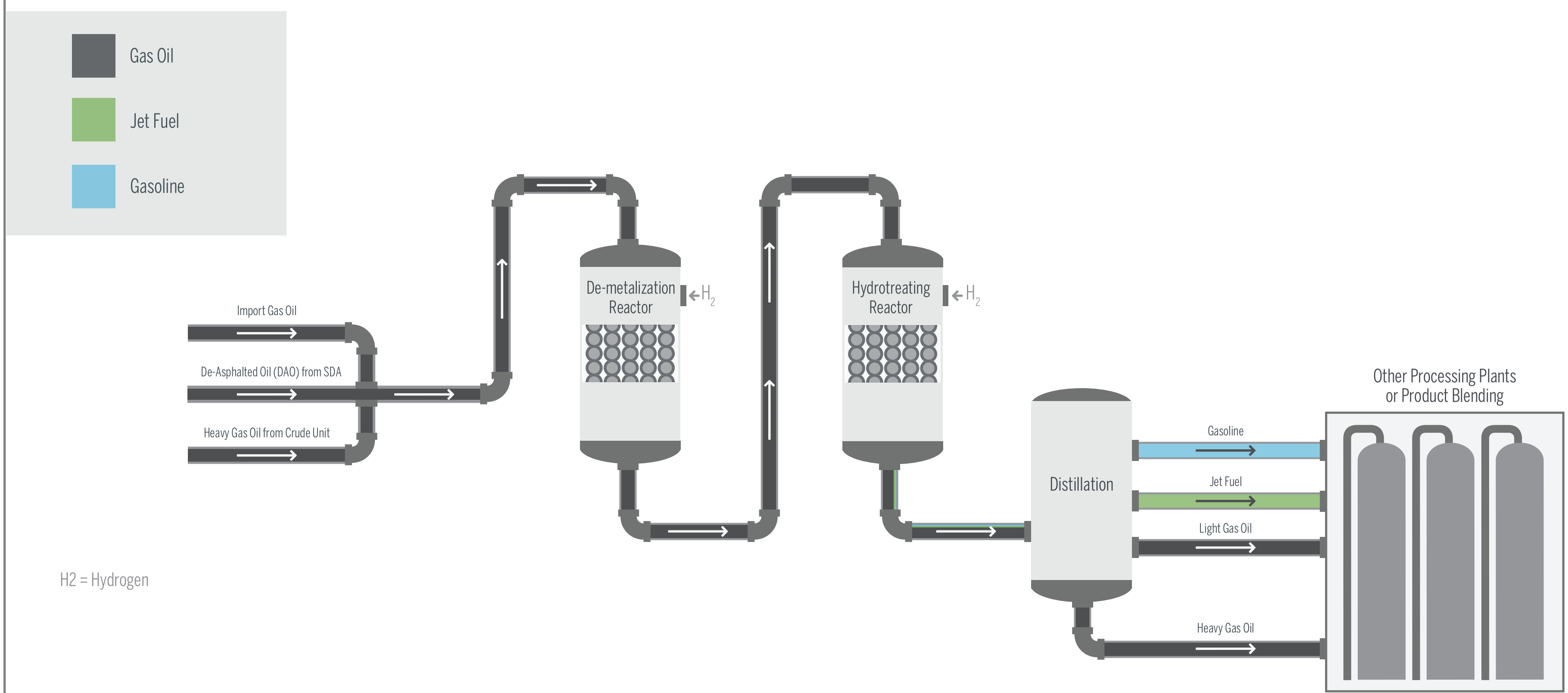
3.4.3 Hydrotreating Removes Sulfur by Reacting Sulfur with Hydrogen to Create Hydrogen Sulfide

In the hydrotreating process, a hydrocarbon stream is fed through a furnace and the hot hydrocarbon and hydrogen gas are charged to a pressurized reactor that contains a catalyst, usually in a pellet form. The combination of catalyst, temperature, pressure, time, and hydrogen causes a chemical reaction in which the sulfur atoms on the hydrocarbon molecule are removed and hydrogen replaces them on the hydrocarbon molecule. The sulfur reacts with the free hydrogen to produce H_2S.

The hydrotreating process requires an excess amount of hydrogen to be present to ensure the greatest removal of the sulfur and nitrogen. Rather than allow the valuable excess hydrogen to be sent to the fuel gas system and burned as a refinery fuel, the excess hydrogen gas from the hydrotreaters is removed in a hydrogen separator and recycled to the process. The output from the reactor is charged to a fractionator to remove the light ends (which now include a combination of usable hydrocarbons, hydrogen, and H_2S). The hydrotreating process is depicted in Figure A3-10, *FCC Feed Hydrotreating Process*.

The FCC Feed Hydrotreating Process

The FCC Feed Hydrotreater (FCC FHT) is designed to remove metals as well as denitrify and desulfurize gas oils prior to being processed by the FCC unit.
Some incidental "cracking" occurs during the hydrotreating process, creating a relatively small amount of lighter products such as gasoline blendstocks and jet fuel.



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Source: Chevron (T39r2)

Figure A3-10
Chevron Refinery Modernization Project EIR
FCC Feed Hydrotreating Process

As shown in the hydrotreating figure, the hydrotreating process relies on hydrogen. As discussed further below, hydrogen comes from four sources at the Facility. It is manufactured at the existing hydrogen plant, it is produced at the reformers, it is recycled when the unreacted hydrogen is recovered from the hydrotreating processes in the Facility, and it is also recovered from process gas through pressure swing adsorption (PSA).

The hydrotreating process occurring in the FCC FHT processing unit also results in some minor incidental cracking, where a catalytic reaction in the presence of hydrogen breaks heavier, longer chain hydrocarbons into lighter, shorter chains like gasoline and jet fuel ("light ends"). This hydrocracking (breaking longer hydrocarbon molecules into smaller ones in the presence of catalyst, temperature, pressure, and hydrogen) is a byproduct of the hydrotreating process. This same cracking phenomenon occurs in all of the hydrotreaters but is less pronounced in the lower pressure hydrotreaters including the NHT, GHT, JHT, and DHT. This "cracking" process is explained further in the next section, since *Cracking* is another major step in the refining process.

3.4.4 Hydrotreating Removes Nitrogen by Creating Ammonia

Similarly, nitrogen atoms on the hydrocarbon molecules are replaced by hydrogen in a chemical reaction, and the nitrogen reacts with free hydrogen to produce ammonia (NH_3).

Hydrocarbon outputs from the various units are frequently steam-stripped (i.e., contacted with steam) or water-washed (contacted with water). The condensed water from steam injected into the processes and water from the water washing process absorb ammonia and some H_2S that were produced in the various units. This water/ammonia/H_2S mixture is charged to a vessel and some of the water is boiled off, yielding concentrated "sour water." The ammonia and H_2S in the concentrated sour water are removed in sour water strippers that heat the sour water and separate the H_2S and ammonia from the water. The water from the sour water stripper is reused or sent to the water treatment facility. The H_2S stream is sent to the sulfur recovery unit. The ammonia is captured and stored for sale or used in the Facility.[8]

[8] Ammonia can be used for removing NOx from furnace stacks in a process called selective catalytic reduction, among other applications..

3.4.5 Amine Treatment Units Remove the Hydrogen Sulfide from Usable Hydrocarbons

As noted above, the *Treatment* step in the refining process also creates byproducts including H_2S that must also be managed. At the Facility, the H_2S gas created by the hydrotreaters is routed to a unit called an "H_2S absorber," which contains a solvent—diethanolamine (DEA)—designed to absorb the H_2S molecules and separate them from hydrogen and hydrocarbon gas streams. DEA liquid is mixed with the hydrogen sulfide rich gas in the H_2S absorber.

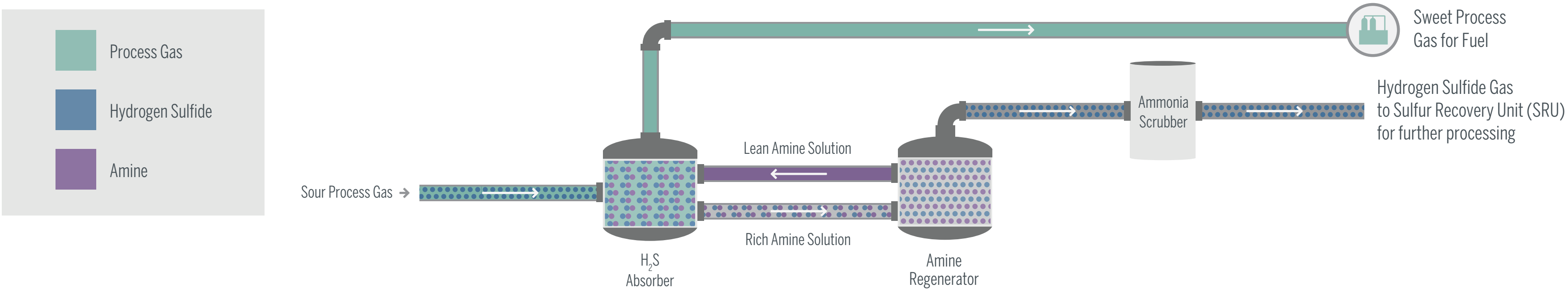
The H_2S absorber produces a liquid consisting of a mixture of H_2S and DEA, which is then piped to an "amine regenerator." The amine regenerator is a vessel where a lower pressure plus heat added by a steam reboiler "flashes" off the H_2S. In the amine regenerator, the H_2S is stripped from the DEA. The DEA is recycled to be used again, and the H_2S gas (no longer containing hydrogen, hydrocarbons, or DEA) is then sent to a sulfur recovery unit, as described below (see Figure A3-11, *Amine Treatment Process)*.

3.4.6 Sulfur Recovery Units Convert Hydrogen Sulfide H_2S Gas into Usable Elemental Sulfur

The separated H_2S stream is sent from the amine regenerator to one of three sulfur recovery units, where it is turned into elemental sulfur, using a process known as the "claus process" as depicted in Figure A3-12, *Sulfur Recovery Process*, below. Some H_2S is burned or oxidized in a furnace, creating sulfur dioxide (SO_2) from the H_2S ($H_2S + ½O_2 = SO_2 + H_2O$). The SO_2 produced further reacts with the unreacted H_2S to produce elemental sulfur ($H_2S + ½SO_2 = ½S + H_2O$). The second step, which produces the elemental sulfur, occurs partially in the reactor furnace and partially in the catalytic reactors. The gases that exit the reactor furnace are routed to a heat exchanger where the elemental sulfur produced in the burner/furnace is condensed and sent to storage. The heat exchanger produces steam for use in the Facility. The gases from the heat exchanger are sent to a vessel that contains a catalyst to continue the conversion of the H_2S to elemental sulfur. The process at the Facility has two conversion stages to produce the majority of the elemental sulfur. The process gas that still contains unconverted H_2S is routed to the equipment called the Wellman-Lord tail gas recovery units, where remaining H_2S is oxidized to SO_2 and returned to the catalytic reactors for further conversion to elemental sulfur. The elemental sulfur that is produced is stored in a tank in a liquid form. It is shipped out of the Facility as a salable product in liquid form by truck.

Amine Treatment Process

An amine solution treats process gases containing hydrogen sulfide (sour gases) generated in the Facility's processing units. The treated gas is used within the Facility as a fuel source and the removed hydrogen sulfide is further treated into an elemental sulfur product.



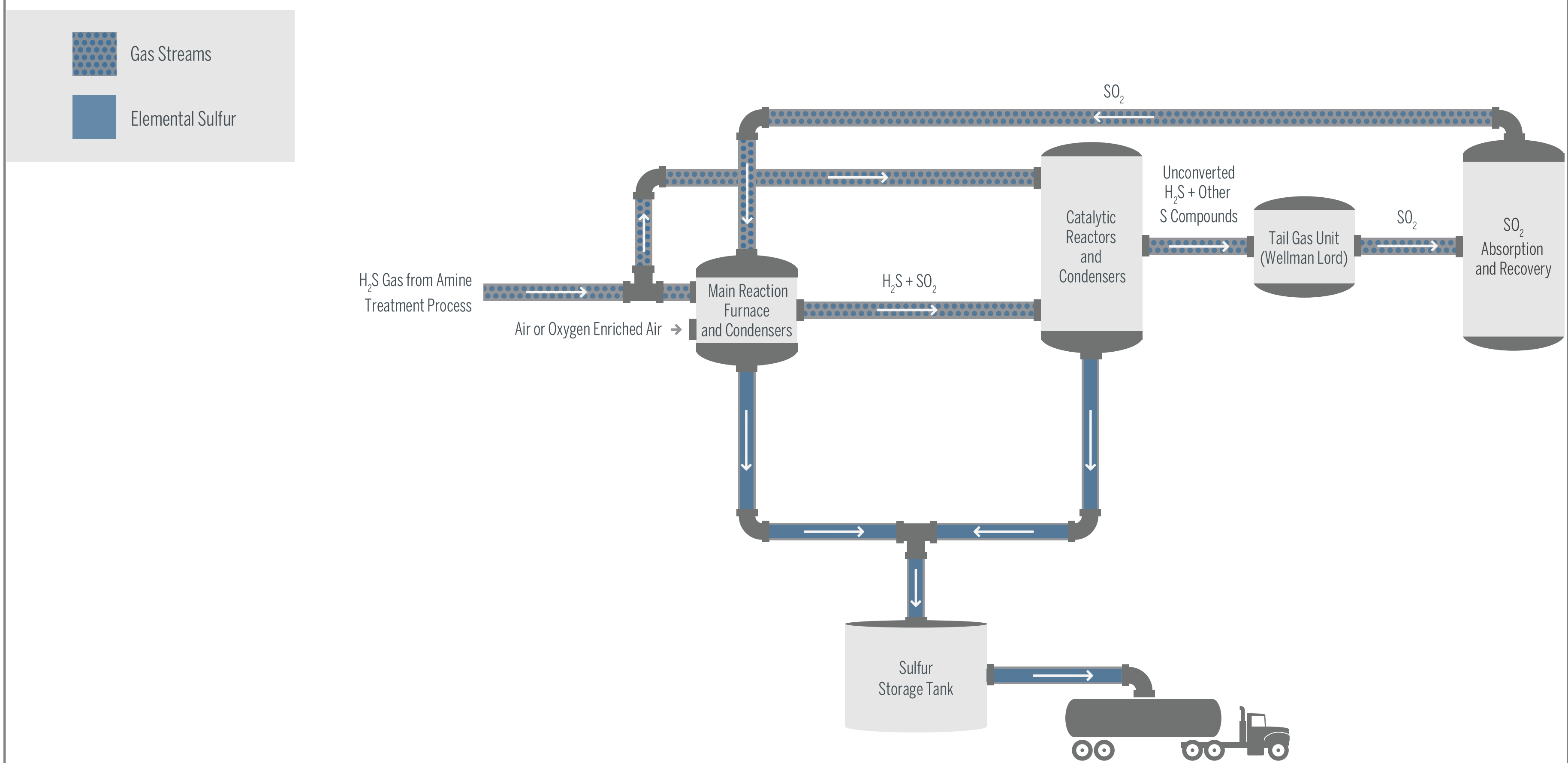
03.04.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B_Refinery 101\Draft\CVRN Figure A3-11.pdf

Source: Chevron (T39r2)

Figure A3-11
Chevron Refinery Modernization Project EIR
Amine Treatment Process

Sulfur Recovery Unit

The Sulfur Recovery Unit (SRU) recovers elemental sulfur from gas containing hydrogen sulfide. The elemental sulfur leaves the refinery as a salable product.



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Source: Chevron (T39r)

Figure A3–12
Chevron Refinery Modernization Project EIR
Sulfur Recovery Process

3.4.7 Conversion: "Cracking" Remaining Heavy Hydrocarbon Molecules into Light Hydrocarbons

After hydrotreating to remove natural impurities including sulfur, many of the crude oil fractions processed by the Facility are suitable for *Blending* prior to sale as products (e.g., gasoline, diesel, jet fuel), or are ready to be blended into specialty products (e.g., lubricating base oils).

However, gas oil fractions must undergo an additional refining process—thermally or chemically "cracking" the long chains of hydrocarbon molecules that comprise these hydrocarbon fractions—to produce gasoline, diesel, and other high-demand petroleum products.

The Facility uses two types of "cracking" technology: catalytic cracking and hydrocracking.

3.4.8 Catalytic Cracking

The Facility's fluid catalytic cracking unit is the fluid catalytic cracker. Catalytic cracking, or "cat cracking," involves heating gas oil fractions to temperatures of around 1,000°F when exposed to a "catalyst" at relatively low pressures (20 to 30 pounds per square inch [psi]) to "crack" the long chain hydrocarbon molecules into shorter chains, and thereby produce lighter hydrocarbons like gasoline. When the long-chain molecules of heated gas oil come into contact with the surface of the catalyst in this chamber, the molecular chains "crack" and become multiple, shorter-chained, lighter hydrocarbon molecules (see Figure A3-13, *Fluid Catalytic Cracking Process*).

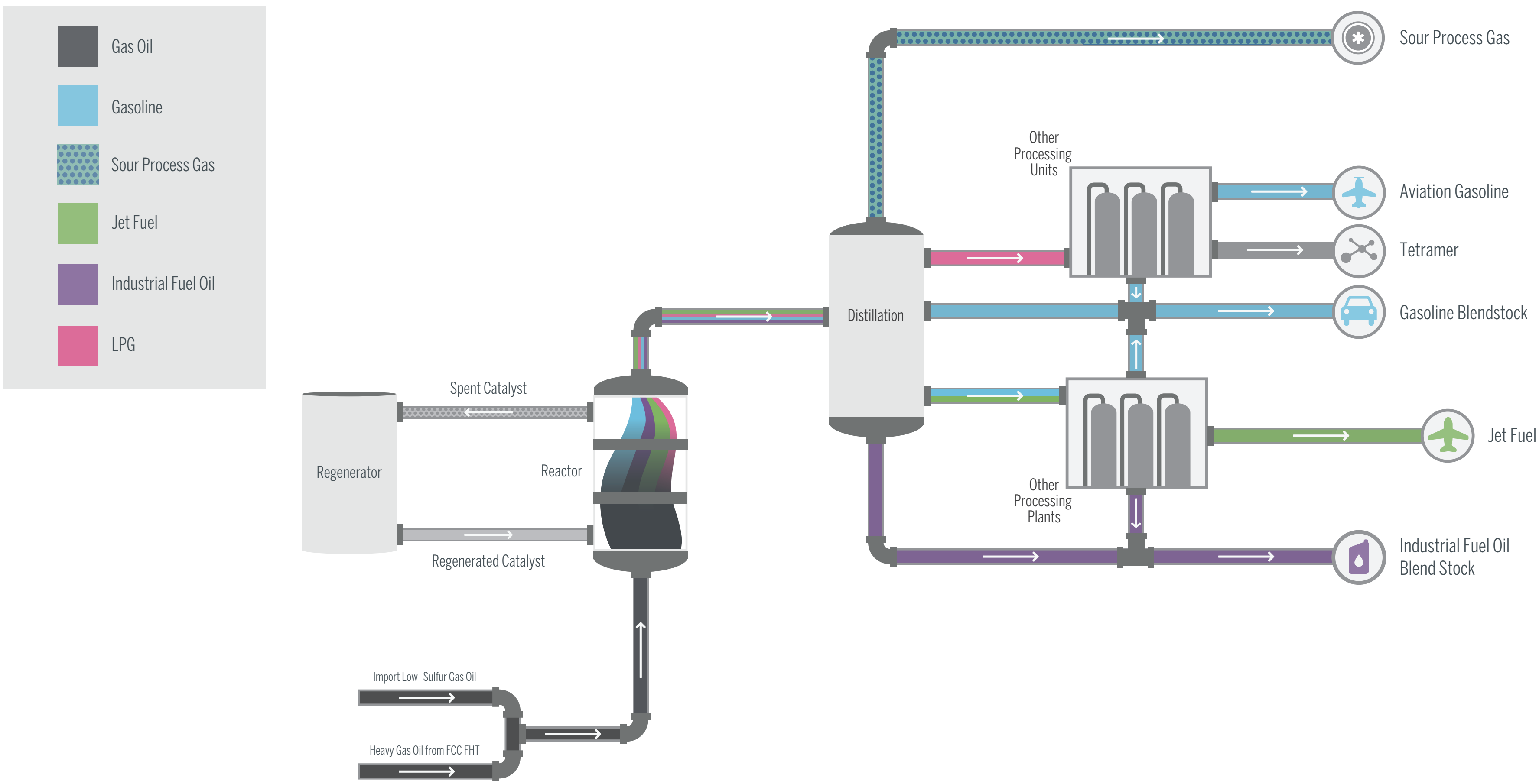
The catalyst in the fluid catalytic cracker itself is a chemical compound with the appearance of a very fine powder. Although it comes into contact with the gas oil, the catalyst remains chemically unchanged and can be used again and again. The Facility's catalytic cracker is called a "fluid catalytic cracker" because the reaction takes place in a vessel where the catalyst particles behave like a liquid.

As the hydrocarbons crack, some of the carbon atoms from the cracked hydrocarbons deposit on the surface of the catalyst, which reduces the catalyst's ability to promote chemical reactions. (This deposit of carbon is often called "coking".) To regenerate the catalyst, air is mixed with the catalyst in a heated environment, and a chemical reaction – the oxidation of coke (essentially burning) – takes place that removes the coke from the catalyst and allows it to be reused.

The fluid catalytic cracker unit receives gas oil from (1) the hydrotreatment process described above, which removes sulfur and other natural impurities; and (2) imported

Fluid Catalytic Cracking Process

The Fluid Catalytic Cracker (FCC) Unit uses catalyst, which moves "fluidly" with the feedstock, to convert larger gas oil molecules into gasoline and other smaller hydrocarbons.



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Source: Chevron (T39r2)

Figure A3-13
Chevron Refinery Modernization Project EIR
Fluid Catalytic Cracking Process

purchased gas oil to the extent that it is already low in sulfur and thus does not require hydrotreatment.

3.4.9 Hydrocracking (TKN Isomax Unit)

The second method of cracking used at the Facility, *hydrocracking*, involves chemical reactions between hydrogen gas and hydrocarbons in the presence of a catalyst, and occurs in a vessel operated at very high pressures on the order of 1,000 to 3,000 psi. The Facility's hydrocracker is called a “TKN Isomax.” Hydrocracking converts gas oil into lighter hydrocarbon fractions. Unlike cat cracking, hydrocracking does not produce significant coke because it adds hydrogen atoms to the cracked molecules instead of releasing carbon atoms. (Hydrogen is used in the TKN Isomax unit in this cracking process and is an example of a refinery process where hydrogen is used in a manner that is unrelated to sulfur.) See Figure A3-14, *The Hydrocracker Process.*

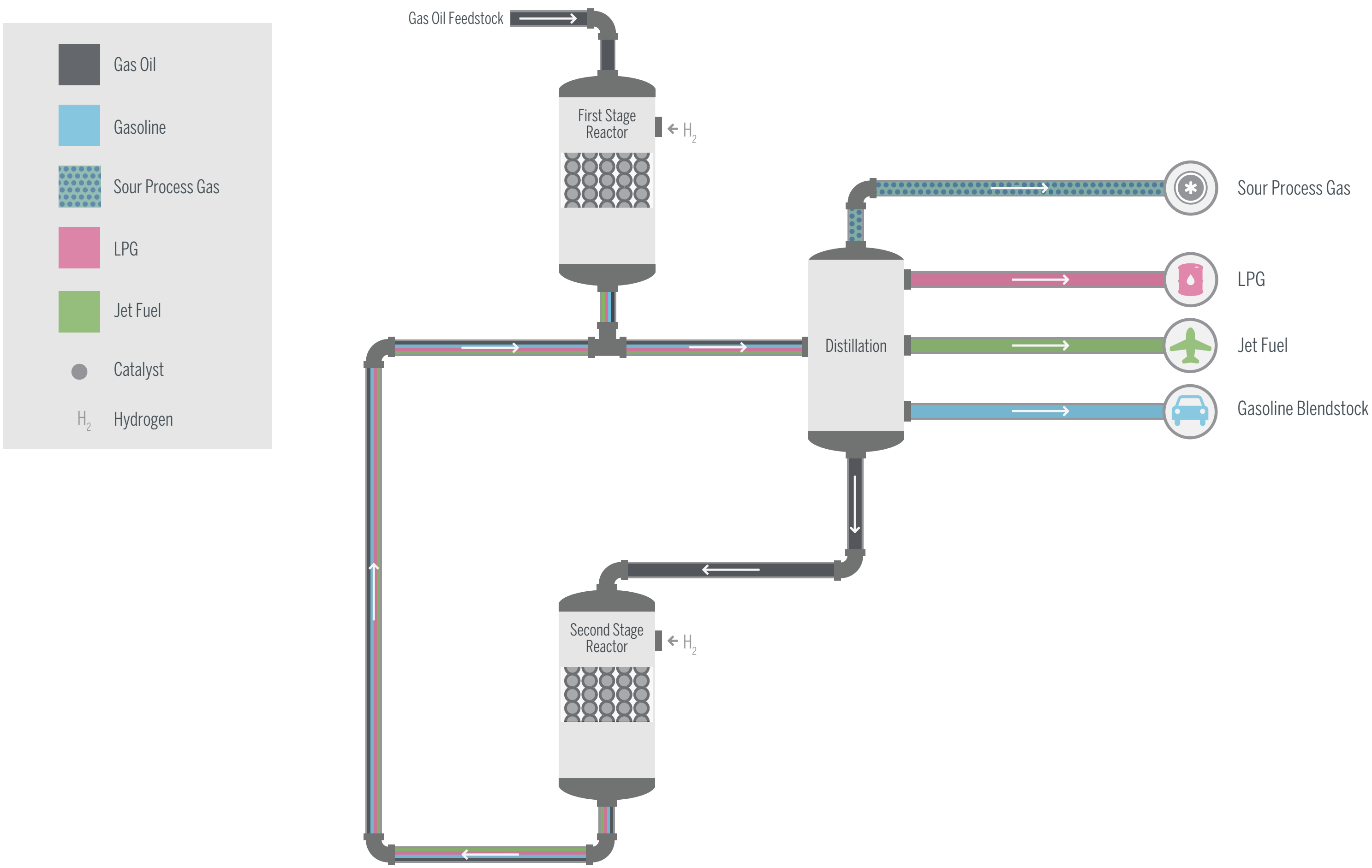
The hydrocracking in the Facility's TKN Isomax unit is a two-stage process that removes impurities from gas oil in the first stage and then “cracks” the gas oil in the second stage. The first stage is called the TKN (Taylor Katalytic DeNitrification). The second stage is called the Isomax. The name of the combined TKN Isomax is typically shortened to just “TKN” because essentially all of the material fed to the TKN is subsequently fed to the Isomax. The TKN unit receives the lighter gas oils produced by the crude unit and treats it to remove impurities, similar to the FCC FHT, which treats the heavier gas oils. The treated gas oil flows from the TKN to the Isomax where the gas oil is cracked into gasoline, jet fuel, and diesel.

The TKN *Treatment* stage removes impurities in a similar fashion as the hydrotreaters. Catalyst, temperature, pressure, and time remove the impurities and hydrogen reacts with sulfur, nitrogen, and hydrogen-deficient hydrocarbons producing H_2S gas and ammonia. As with hydrotreaters, the H_2S produced by the TKN is absorbed in a H_2S absorber by a DEA solvent for further treatment and recovery of elemental sulfur product through the amine regenerators and ultimately the sulfur recovery units. The TKN unit operates at temperatures and pressures that allow the sulfur and nitrogen in the gas oil feed to be converted to H_2S and ammonia for eventual recovery as either salable sulfur or ammonia product.

In the hydrocracking (Isomax) stage, a catalytic reaction in the presence of hydrogen cracks the bigger gas oil molecules into smaller gasoline, jet fuel, and diesel molecules. Since both units use hydrogen, there is some incidental cracking in the TKN and there is some incidental removal of impurities in the Isomax.

The Hydrocracker Process

A Hydrocracker unit uses hydrogen and catalyst to convert ("crack") larger hydrocarbon molecules into jet fuel, gasoline and other smaller hydrocarbons.



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Source: Chevron (T39r2)

Figure A3-14
Chevron Refinery Modernization Project EIR
The Hydrocracker Process

Neither catalytic cracking nor hydrocracking creates or destroys hydrogen, carbon, nor any other atom. As larger hydrocarbon molecules are broken, they create larger numbers of smaller molecules. Those smaller molecules have the same molecular weight as the sum of the initial larger molecule plus the very light hydrogen gas, but the smaller molecules collectively take up more space (or volume) than the initial, larger, more dense molecule from which they were created. This expansion of volume through the hydrocracking process is called "processing gain" and it results in production (by volume) of slightly more hydrocarbon lighter end products than the volume of gas oil introduced to hydrocracker units. U.S. refinery processing gain averaged about 6.2% from 1996 through 2010. In 2012, about 44.98 gallons of refined products were produced for every 42 gallon barrel of oil input into U.S. refineries.

3.4.10 Reforming: Increasing Octane Levels in Gasoline

Reforming is a process primarily designed to increase the "octane" of gasoline. Octane is a characteristic of gasoline related to the tendency to "self-ignite" under pressure.[9] Engines are rated based on their ability to run lower- or higher-octane gasolines. High-performance engines generally need higher-octane gasoline. If the octane level in the gasoline is not suitable for the engine, premature ignition of the gasoline occurs in the cylinder—a condition known as "engine knock" because of the knocking sound that is made when the gasoline ignites too early in the engine's compression stroke. Octane ratings in commercial gasoline range from about 85 anti-knock index (AKI) in regular gasoline in high altitudes like Denver, Colorado, to over 100 for aviation gasoline.

Severe knock causes severe engine damage, such as broken connecting rods, melted pistons, and melted or broken valves and other components. An octane rating is a measure of how likely a gasoline or liquid petroleum fuel is to self-ignite. The higher the number, the less likely an engine is to pre-ignite and suffer damage. California allows a range of octane levels at the pump (87, 89, and 91), and buyers can choose the octane level that is appropriate for their car and budget. Higher octane ratings are typically recommended for higher-performance engines, and higher octane levels also cost more per gallon at the retail level than lower octane levels.

The "reforming" process in the Facility takes hydrocarbons that are in the naphtha weight range but have low octane and changes their molecular structure into higher-octane gasoline molecules. The reforming process involves reshaping because the naphtha has the same number of carbon atoms before and after this

[9] Octane is also a name for some hydrocarbons that include eight carbon atoms.

part of the refinery process, but the molecules are "reshaped" into higher-octane gasoline molecules. This reshaping of molecules also releases hydrogen, which is then used in other Facility processes as part of the Facility's overall hydrogen supply.

The Facility has two catalytic reformer process units (#4 and #5 Rheniformer), each of which consists of four separate catalytic reactors. As with other refinery processes using catalysts, each of these reactors consists of a chamber containing the catalyst material, operated at controlled temperature and pressure levels. Naphtha from the naphtha hydrotreater (which removed sulfur from this naphtha hydrocarbon fraction) is fed through each reactor chamber in series. The feed is treated with perchloroethylene, a chemical that provides chloride atoms to control reforming catalyst activity.

The products of reforming are light gases and a high-octane gasoline component typically called reformate. Hydrogen gas, a by-product generated in this process, is recovered and used in other Facility processes. The light ends produced at the reformer are used in gasoline blending (normal butane), alkylation unit (iso-butane), liquefied petroleum gas (propane) or refinery fuel gas (methane or CH_4). The reformers at the Facility are "semi-regenerative," which means that they accumulate coke as hydrocarbons are passed over them and a small amount of cracking occurs. This coke must be burned off periodically, which is called "regeneration." The frequency of the regeneration depends on the octane level achieved for the reformate. Higher octane results in more frequent regeneration. Typical regeneration cycles are every 6 to 24 months and regeneration only takes a few days, unless significant other work is required on the unit.

3.4.11 Specialty Operations: Lubricating Base Oil Production Process

The Facility is also a major national producer of industrial lubricant base oils. This requires a specialty process consisting of gas oil hydrocracking. Gas oil from the crude unit is routed to the lube unit crackers. These are similar in operation to the FCC FHT, but instead of producing a primary output of gas oil for use in the fluid catalytic cracker, they produce material used as input to the lube hydrofinishers. The lube hydrofinishers also use hydrogen to treat this material and ultimately produce a base oil that is the primary building block in producing lubrication oil with the desired physical properties such as viscosity and density.

The base oil production process includes sulfur removal from the feed. The sulfur removal process is the same as the other hydrotreating units. Lighter ends that include H_2S produced in the lube crackers are directed to a H_2S absorber to remove the H_2S by absorption in DEA. The H_2S rich DEA is regenerated in an amine regenerator and the H_2S is changed to elemental sulfur in the sulfur recovery unit.

3.4.12 Blending and Final Product Production Process

The Facility processes produce hydrocarbon fractions that are products ready for shipment, and it also produces hydrocarbon fractions that require blending with other hydrocarbon fractions before being ready for shipment as products. *Blending* typically occurs when hydrocarbon fractions are piped to a tank in specific quantities until required product specifications are achieved. All of the Facility's hydrocarbon products are produced either by one or more of the refinery process steps described above, or by blending hydrocarbons produced by one of the refinery process steps described above. How much of any particular product is produced varies based on market factors, but the Facility has consistently served as a primary supplier of gasoline, jet fuel, and base oils in the region.

3.5 OTHER REFINING PROCESS OPERATIONS

The Facility also includes other major equipment and activities that are integral to Refinery Operations but not technically part of the Facility's process for producing products. Other major categories of Refinery Operations described in this section include the Facility's hydrogen plant, furnaces, flaring system, power plant, wastewater treatment plants, and storage tanks.

3.5.1 Hydrogen Plant

As described above, hydrogen plays a critical role in the refinery process steps described above, including in the catalytic processes for removing sulfur in the *Treatment* processes, breaking bonds and forming new bonds in the *Cracking* processes, and the production of lubricant base oils. Hydrogen gas is produced on-site in an existing hydrogen plant as well as from the *Reshaping* process.

3.5.2 Hydrogen Manufacturing Technology

The current hydrogen plant produces hydrogen from a process known as "steam reforming." The chemistry of the existing plant is relatively simple. Water (H_2O) is combined with methane (CH_4, the primary component of natural gas) which, through a chemical reaction, produces hydrogen, carbon dioxide (CO_2), and carbon monoxide (CO). This steam reforming reaction is typically carried out using a nickel catalyst, which is packed into tubes of a reforming furnace.

In the mid-1980s, PSA generally replaced the older technology (Meyers, 2004). As explained further below, the primary difference between the two processes is that the final product from the steam reforming process described in the prior paragraph (about 94% pure hydrogen) goes through an additional step in the newer technology in which it is sent to PSA vessel units, where the hydrogen is selectively absorbed at high pressure, leaving the impurities like CO_2 behind. The absorption mixture is depressured, and very pure (99%) hydrogen is all that is left. The impurities and some hydrogen left in the PSA units are burned in the furnace to provide heat for the reaction.

3.5.3 Furnaces, Burners, Heat Exchangers and Thermal Oxidizers

Heating devices provide heat to various liquid or gas streams such as water, process streams (e.g., crude oil), or air. In general, these heating devices are referred to as “furnaces.” Sometimes, heating devices are given special names based on the stream being heated. For example, a heating device that boils water is commonly referred to as a “boiler.” A heating device that provides heat to non-water liquid streams is sometimes also referred to as a “process heater.” However, the general operation and the emissions associated with each are similar in concept.

These heating devices all include burner assemblies. The burners are where fuel (i.e., natural gas or refinery fuel gas) is combusted with oxygen to form a flame and hot combustion gases. (This is a larger scale version of the burners that one would find on a natural gas kitchen stove.) There are different ways a hydrocarbon stream may be heated during the refining process, depending on the configuration of the heating device and the technology of the refining process that the heating device serves. For example, a hydrocarbon stream being heated may pass through tubes that are surrounded by the hot combustion gas. In this case, the heat from the hot combustion gas transfers through the tube, increasing the temperature of the hydrocarbon stream within the tube. The flame component of the heating device may also be near the hydrocarbon stream, which would directly transfer additional radiant heat to the stream through the tubes.

In certain process units, burners are used to directly combust a refinery process stream (i.e., the material being processed through the Facility unit comes into direct contact with the flame from the burner) instead of using burners just as heaters. This occurs, for example, when hydrogen sulfide gas is combusted as part of the sulfur recovery unit process in the *Treatment* process for sulfur removal.

In addition, some burners are designed to combust volatile organic compounds (VOCs) in exhaust streams or fugitive emissions, converting the VOCs into CO_2 and water. Such devices are called thermal oxidizers. Thermal oxidizers are used, for example, to control VOC emissions from pumps and compressor seals at the Facility.

The combustion process for all heaters produces air emissions. The pollutants produced depend on the chemical composition of the fuel and combustion air and can include criteria air pollutants, toxic air contaminants, and greenhouse gases. The design of the device can influence the extent to which air emissions are generated. For example, low-NO_x burners are designed to reduce NO_x formation by controlling fuel and air mixing. Air emissions from burners are described in *Section 4.3, Air Quality*, and *Section 4.8, Greenhouse Gases*.

The combustion gas from a heating device typically remains hot even after transferring heat to the material being refined in the part of the refinery process served by the heating device. This combustion gas can be released as exhaust through a flue stack (subject to required air pollutant controls), or an "economizer" can be used to recover heat from the exhaust gas that would otherwise be released into the atmosphere. The recovered heat can be reused in the refining process to pre-heat a process stream or combustion air, which then results in lower fuel consumption because less fuel is used to bring the stream or combustion air up to operating temperature. An economizer is essentially a "heat exchanger" (described below) that reduces fuel consumption from the same device from which it derives its waste heat. The waste heat from the combustion gas could also be used to heat other streams derived from other units in a conventional heat exchanger.

A "heat exchanger" is a piece of equipment whereby a hotter process stream transfers heat to a cooler process stream. The two process streams do not come into direct contact with each other (i.e., they are not mixed). Rather, they are generally separated by a metal wall that conducts the heat from one stream to another. Heat exchangers are designed such that the surface area of the wall separating the two streams is maximized in order to maximize the amount of heat transferred. There are no emissions associated with heat exchangers because there is no combustion occurring. For example, the hot gases that exit the sulfur recovery unit enter into a heat exchanger where it transfers heat to a stream of water, converting the water to steam.

3.5.4 Flares

A refinery moves raw materials through a network of pipes and processing equipment. As described above, many of the refining processes involve using pressure and/or heat to change hydrocarbons and transporting heated or pressurized hydrocarbons through the different parts of a refinery. Flare systems are designed to provide for the safe disposal of hydrocarbons that are either automatically vented or manually drawn from process units at refineries. Hydrocarbons must be controlled in a safe and effective manner in the event of an operational upset. Flare systems gather vented gases and combust them to prevent releases of hydrocarbons directly into the atmosphere.

Flaring plays a critical safety role in refinery operations. A “flare” is usually a tall stack equipped with burner equipment that is designed to ignite hydrocarbon gas when it leaves the flare. This flare technology is designed to very quickly and very efficiently consume hydrocarbon gas (similar to a gas stove), with minimal air pollution. The primary function of the flaring system is to relieve pressure to prevent units from overpressure. Flares are primarily used for burning off flammable gas released by a “relief gas header” during either unplanned pressuring of refinery equipment, or during startups and shutdowns. A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. At the Facility, these are typically referred to as “relief gas headers,” since the system, which is generally at near-atmospheric pressure conditions, receives gases “relieved” from higher pressure operations within the unit.

The primary function of the relief gas header is safety. It provides the process unit with a readily available and controlled means of releasing gases to prevent over-pressurization of equipment (routing them to controlled locations for destruction by combustion). It also provides a controlled outlet for any excess vapor flow, nearly all of which is flammable and can be sent to a flare to be burned off, making it an essential safety feature of every refinery. Each relief gas header has connections for equipment depressurization and purging related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices and other safety control valves to handle upsets, malfunctions, and emergency releases.

The Bay Area Air Quality Management District (BAAQMD) has been a global leader in regulating the use of flares. Flaring is not required to operate a refinery's process units during normal operation, and the need for flaring at the Facility has been substantially reduced over time.

The Facility has identified situations or activities likely to cause flaring, including releasing gases to prevent equipment from becoming over pressured, as described below in more detail. Releases of relief gas to the flare result from an imbalance between the quantity of vent gas produced by the Facility and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds), and utilized as fuel gas. Situations that can lead to flaring can be grouped together based on similarity of cause. At the Facility, flares are used for three primary purposes:

- **Process unit startups and shutdowns and planned maintenance.** To prepare an individual equipment item or a block of refinery equipment for maintenance, it is necessary to isolate it from active operations and clear it of process fluids. Examples include unit shutdowns, working on equipment and/or relief systems, catalyst change, plant leak repairs, and compressor maintenance or repairs. In order to avoid flaring, there must be a balance between producing and consuming fuel gas units. When either a block of equipment or an individual equipment item is removed from service, if it either produces relief gases or consumes fuel gases, then the balance of the fuel gas system is changed and adjustments are necessary to bring the system back into balance. If the net change in gas production or consumption is large and the adjustments in the rate at which gas is produced or consumed by other units cannot be made quickly enough, then flaring results.

- **Upset/malfunction.** An imbalance in the flare gas system can also result from upsets or equipment malfunctions that either increase the volume of flare gas produced or decrease the ability of the fuel gas handling system to accommodate it. Examples include relief valves lifting, pressure relief valve malfunction, equipment overpressure, loss of a utility system, and loss of air fins or condensers.
- **Emergency relief.** Pursuant to BAAQMD Regulation 12, Rule 12, Section 201, an emergency "is a condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility."

To address these situations, the Facility currently operates two flare gas systems, complete with flare gas recovery systems, one covering the "north yard" of the Facility and the other covering the "south yard."

The operation of the Facility's flare systems is governed by its flare management plan (FMP) submitted pursuant to the requirements of BAAQMD Regulation 12, Rule 12 (Reg. 12-12). The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Flaring is prohibited unless it is consistent with an approved FMP. Each refinery is required to submit a FMP annual update. The FMP defines a series of measures intended to reduce flaring to the extent that is feasible without compromising safety and necessary refinery operations and practices. It is the Facility's policy that flare events would only occur within the scope of Reg. 12-12, and it would adjust the operation of process units or implement corrective action to prevent flaring in accordance with the regulation.

3.5.5 Power and Steam Generation, Including Boilers

The Facility is designed to generate on-site most of the power it needs to operate. During the baseline period of 2008-2010, the Facility imported an annual average of only 2 megawatts (MW) of electricity, compared to a total annual average of approximately 115 MW of electricity used by the Facility.

Electric power is generated at the Facility by two gas turbines, one steam turbine generator, and the fluid catalytic cracker power recovery system. The gas turbines generate electricity through the combustion of fuel which moves the blades of a turbine, providing mechanical power to operate the electric generator.

A steam turbine generator creates electricity when higher pressure steam is reduced to lower pressure steam, resulting in mechanical power to operate the electric generator. Steam is produced by two heat recovery steam generators at the co-generation unit as well as five fired boilers in the "No. 1 Power Plant."[10] (The combination of the gas turbines, the heat recovery steam generators, and the duct burners comprise the co-generation facility.)

Steam is also generated by process units throughout the Facility. For example, steam is generated in a heat exchanger that takes in hot gases from the sulfur recovery unit, transfers the heat to a water stream, and converts that water to steam. In addition to being used to generate electricity in the steam turbine generator, steam is also piped throughout the Facility and is injected into various processing equipment to be used for heating in the refining process (similar to radiator heat in a house) or for direct contact with hydrocarbons during the refining process.

The Facility uses approximately 2.5 million pounds of steam per hour. However, the boilers in the No. 1 Power Plant generate only about 10% of that amount; the remaining steam is produced by refinery processes.

3.5.6 Cooling Towers

Process streams require cooling that is usually provided by water in a heat exchanger. Water that picks up heat in the process is sent to a cooling tower where the water is dispersed into thin streams through which air is passed. The

[10] The five boilers are called the "No. 1 Power Plant" because the unit was built in the 1930s and used to generate electricity. However, "power plant" is a misnomer as the unit today consists of boilers only and generates only steam, not electricity.

air evaporates a small amount of the water and the evaporation cools down the water, which is then pumped back to the heat exchanger again for reuse.

3.5.7 Water Use and Treatment

The refining process results in industrial wastewater that is treated in a wastewater treatment facility. The Facility's process wastewater and most of the stormwater runoff is collected and managed in the Facility's existing industrial wastewater treatment system that is regulated by the RWQCB.

3.5.8 Storage Tanks

The Facility currently operates approximately 160 aboveground storage tanks (including pressurized spheres) containing raw materials, feedstocks, intermediate material, and final products. There is a number of small/axillary tanks located throughout the Project site that are not part of the primary Refinery Operations processes.

Most tanks store raw feedstocks (crude oil and gas oil), intermediate stocks, or finished products (gasoline, diesel, jet fuel, etc.). These tanks are located in areas of the Facility known as the Refinery Process and Tank Farm areas (see *Figure 3-2* in *Chapter 3, Project Description*). Furthermore, some tanks store chemicals that are involved in Refinery Operations but are neither feedstocks nor product, such as perchloroethylene used in the reforming process.

The tanks range in capacity from under 1,000 barrels to over 650,000 barrels. Over long periods of time (e.g., annually) the average amount of material stored in tanks is approximately constant, but the quantity of material flowing through the tanks on any given day increases or decreases as the feedstock tanks are emptied into the Facility (or product is produced by the Facility feed rate and production volumes change).

3.5.9 Pipelines, Valves, Pumps, and Flanges

The Facility has a complex network of pipelines, and the pipelines have process components that each result in small emissions of hydrocarbons from the seals in the process components. These process components include approximately 5,000 miles of pipe, 105,000 valves (including pressure relief devices), 1,400 pumps and compressors, and 400,000 connectors such as flanges (which are used to connect two lengths of pipe).

3.6 REFERENCES—APPENDIX 3

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CONTRA COSTA
HEALTH SERVICES

Major Accidents at Chemical/Refinery Plants

in Contra Costa County

Company Date Accident Occurred	Accident Description	Onsite Impact	Offsite Impact
Chevron August 6, 2012	# 4 Crude Unit Fire. An 8" line from the atmospheric distillation column with hot diesel like material leaked and caught fire.	5 Chevron emergency responders were treated for minor burns, and received first aid.	More than 15,000 people sought medical attention.
Phillips 66 June 15, 2012	A sour water tank (T-294) was overpressured resulting in a split in the top seam of the fixed roof tank. Vapors left the tank through the opening until it could be sealed. Chemicals involved included H_2S, other sulfur	Atmospheric tank T-294 was overpressured resulting in a rupture along approximately 20 feet of the top seam of the roof. The rupture allowed vapors from the tank to exit into the surrounding area. H_2S was	Strong sulfur odors were detected by Hazmat IR personnel on Friday in areas from I-80 and the surrounding communities. The highest readings were approximately 1 ppm (as H_2S) on I-80, which is a few hundred feet from the storage tank. Readings from 5-20 pp

	compounds, natural gas, light hydroca	one of the chemicals detected onsite although ma	
Tesoro Golden Eagle Refinery December 9, 2010	Partial Power outage due to damage at substation led to excess flaring and some unit shut down. CWS 2 activated at 10:31. CCHMP monitored the surrounding area and no hazardous substance was detected. Incident downgraded to CWS 0 at 13:18.	Plant-wide partial power due to fire and later explosion at Switching Station #7.	Significant flaring due to loss of power to mulitple units.
Tesoro Golden Eagle Refinery November 10, 2010	Power outage from 3rd party power and steam supplier led to excess flaring and refinery-wide shutdown, very dark smoky plume. At 16:14, CWS 2 and at 16:45 upgraded to CWS 3. CCHMP monitored the surrounding area and took air samples. No	Complete refinery shutdown, and a grass fire around the flare.	Visible smoke and reports of burnt grass smell in N. Concord.

	hazardous substance was detected.		
ConocoPhillips October 22, 2010	Third party (Air Liquide) hydrogen plant tripped resulting in elevated pressue in the Refinery's fuel gas system, and decreases in available hydrogen and steam to the Refinery. One turbine at the Refinery power plant immediately tripped further reducing a	Overpressured fuel gas system resulted in flaring. Loss of steam and hydrogen resulted in a slow down of some units. Power plant turbined tripped off resulted in smokey flare and further slow down of select operations. No equipment damage was reported.	The BAAQMD received a number of complaints of visible smoke and odor in the area. No contaminants were found in community air samples taken by Refinery personnel. No activity was seen on the Refinery's fenceline monitor.
Tesoro Golden Eagle Refinery October 10, 2010	At 12:20, fire on Tank 650 (foul water), contractor was replacing seal. Tank has a 3′ diesel to layer for odor control. One Contractor treated for smake inhalation, released same day. No odor reported. All clear at 16:10.	Emergency Operation Center was activated. No reportable quantities of hazardous compounds were exceeded.	visible smoke plume, but air monitoring by Tesoro industrial hygiene yielded non-detect levels.
Reactions	A brass valve was	The loss of	Toluene went

	Reactions Products May 5, 2008	A brass valve was removed from a bottom of a storage tank partially filled with toluene. The removal looked ot be a theft of the valve over a weekend when no one was at the facility. Over 3,000 gallons of toluene was released. The spill went offsite into a ditch that run through the wetlands between Parchester Village and the Bay. The release was found on Monday morning and the US Coast Guard responded and requested that a shelter-in-place be called. The Parchester siren was sounded and information went out over the media to notify the residents of the shelter-in-place.When Health Services Hazardous Materials Response Team arrived onsite	The loss of over 3,000 gallons of toluene.	Toluene went offsite into the wetlands. The toluene was in a ditch that runs along the border of Parchester Village. Toluene odors were noticeable in the Parchester Village. Siren was sounded and the residents of Parchester Village were requested to shelter-in-place.

		arrived onsite and took measurements of the amount of toluene in the air, the shelter-in-place was lifted. Health Hazardous Materials Programs is classifying this incident as a Community Warning System Level II and a Major Chemical Accident or Release Severity Level II, because if the toluene ignited the damage and consequences of the incident would be major.		
	Calpine Los Moedanos Energy Center May 24, 2007	While overseeing the unloading of a bulk delivery of corrosion inhibitor, approximately 300 gallons of Nalco Trasar 3DT177 (phosphoric acid) was inadvertently unloaded into a storage tank containing about 378 gallons of 12.5% Sodium Hypochlorite	The incident resulted in a chlorine gas release in which the Field Operator and two other plant employees were exposed to. The three plant employees inhaled chlorine gas resulting in throat irritation and	Shelter-in-place was declared for the area north of the Los Medanos Energy Center for about an hour. No offsite complaints were received. CCHS Hazardous Materials Response Team conducted air monitoring outside of the affected building with the highest level of chlorine at 0.15 ppm. Air sampling conducted at

		solution. The chemical reaction of the two products resulted in a chlorine gas release in which the Field Operator and two other plant employees were exposed to. The three employees were transported via ambulance to the Mt. Diablo Medical Center for observation. Time of injury was reported to be 8:30 a.m.	minor chest pains. Three plant employees transported to Mt. Diablo Medical Center for observation. Symptoms identified as moderate throat irritation for all three employees and one of the employees complained of tightness in the chest. The emergency response team (consisting of local fire, police, paramedics, and the County HAZMAT team) isolated plant entry and perimeter access, removed non-essential personnel off-site, and notified neighboring plants. The facility flushed the neutralized	various locations of the plant perimeter indicated non-detect.

		contaminated tank contents to the cooling tower and ventilated affected building.	
ConocoPhillips March 18, 2007	Sulphur plant shutdown due to electrical failure. XS sulfur to flare.	Haze in flare plume.	No complaints were received from the community.
Chevron Richmond Refinery January 15, 2007	"At 5:33 Chevron upgrades incident to Level 3 and sent message that there was a fire at the #4 Crude unit. Initial notification was 5:23 for a Level 2. Operators were in the process of shutting down the plant in preparation for scheduled maintenance. - Information About the Chevron January 15 Fire	Fire near Vacuum column bottoms pump. One employee was treated for minor burns and released to return to work on the same day. Another employee received on-site treatment for minor skin irritation.	Sirens were sounded and TENS Zone 3 & 4 was activated. Unknown amount of hydrocarbons was combusted, resulting in a release of sulfur dioxide. Air monitoring did not indicate adverse air quality impacts.
General Chemical - Richmond June 23, 2006	The main turbine tripped and the shutdown interlock on the combustion air blower did not work correctly, so the blower pressured up the upstream side of the system which is normally under a vacuum.	The plant shut down.	Four Chevron employees were exposed. No other public appears to be affected. Wind at the time of the release was blowing towards Chevron.
ConocoPhillips May 1, 2006	Cogeneration Turbine "C" trippped off. The electrical systems powered from the	Some units shutdown	Smokey Flare for about 10 to 15 minutes

		generator lost power resulting in the shutdown of some units including the wet gas recovery compressor which is believed to have resulted in liquid to the flare system which caused the flare gas recovery compressor to shutdown which resulted in the flaring event. The steam system slumped due to the loss of the "C" turbine which resulted in lower that desired steam to the flare tip resulting in some incomplete combustion or a "smokey" flare.		
	Shell Oil Products U.S Martinez Refinery March 26, 2006	At 4:15pm, on Sunday 3/26/06, Shell Martinez Refinery reported via the Community Warning System a release of sulfur dioxide gas from the stack of Sulfur Recovery Plant #3 (SRU#3). Community Warning System sirens were sounded. Shell identified the release as a Shelter-in-Place because a visible plume was seen drifting across Shell Avenue and facility personnel at the time believed the plume could pose a health	Shutdown SRU#3 briefly to assess for damage, found none, then returned to normal operation. Refinery officials did not report any injuries associated with this event. Refinery officials did not report any visible external damage to equipment. There may have been elevated temperatures in one of the catalyst beds that resulted in producing sulfur	Visible plume released from SRU#3 stack. Level 3 called with sirens and TENS activated. Pluming stopped in 15 minutes. Following the notification, Hazardous Materials Program staff responded to the incident within ten minutes by assessing the area around the refinery. Hand held monitoring equipment did not detect any sulfur dioxide or hydrogen sulfide. A slight sulfur dioxide odor was detected at Shell Avenue and Marina Vista. Feed to the process was shut off which quickly

	hazard. . TENS zones 3 and 2 were activated.Visible pluming stopped within 15 minutes. Shell Avenue was closed for 25 minutes. Shell downgraded the event to a CWS Level 0 within 40 minutes after the event started.	dioxide gas. CCHS Hazardous Materials did not receive word of any injuries or offsite impacts associated with this release.	stopped the visible pluming.
Tesoro Golden Eagle Refinery March 24, 2006	Fire at #2 HDS at the F-20 furnace outlet piping at 15:38 hrs. Operations personnel shut down unit and activatd fire monitors on the unit.	Flange failure led to fire and unit shut down	No community complaints were received by BAAQMD
Shell Oil Products U.S Martinez Refinery November 8, 2005	At the FCC Unit, a 1 to 2 foot diameter slurry filter was taken off line to clean the filter. While the maintenance team was in the process of placing the/a clean filter back in the filter unit or housing, they noticed a small leak through the block valve, which quickly became big, and one person was not able to vacate fast enough, the material jet was approximately 200 feet in the air. The event started on 11/8/05 at about 8:24 pm. It was downgraded to a level 0 at about 2:54 am on 11/9/05. The event took 30	One contractor was sent to San Pablo Medical Center with 1st, 2nd, and 3rd degree burns on head on arm. No fire occurred. Some flaring occurred, Oil and catalyst slurry spray residue coated neighboring equipment and took days to clean up.	Oil/catalyst slurry mist coated vehicles and pavement southwest of the refinery. No offsite injuries reported. Approximately 150 gallons of total material was estimated to travel offsite. No hydrocarbon or H2S was observed in facility air samples. Some flaring occurred and resulted in estimates of 62.6 lbs SO2 and 0.9 lbs Nox from the flare system. Oil droplets were observed on cars and pavement southwest of the refinery.Approximately 3000 insurance claims from community members have been filed as of the 30-day report

	The event took so long to get under control because the liquid was hot, about 700F at 80 psig. 150 barrels of material was released and comprised of cat cracked slurry oil (heavy, dark oil) and lighter flushing oil (diesel type). Slurry oil comprised about 1% of total material.		report.
Tesoro Golden Eagle Refinery October 26, 2005	Partial power outage at the refinery around midnight and early morning hours, resulted in upset and flaring at the Chem Plant.	Power outage lead to ammonia recovery unit shutdown to reduce acid gas load to sulfur plant.	A plume from chemical plant stack was visible from off-site and potentially contained Sulfur Dioxide. Odor patrol from Tesoro was in the Clyde area and reported no odor impact. Ground Level Monitors did not detect any sulfur dioxide or hydrogen sulfide.
Tesoro Golden Eagle Refinery August 24, 2005	Lube oil fire from mini blower near the main blower at FCCU.	3665 pounds of lube oil est. to be combusted in the fire. No injuries.	Heavy smoke, one odor complaint from Bay Point.
General Chemical-Richmond July 26, 2005	A flow meter on a feed to the oleum stripper in the CP Plant developed a leak. The facility estimates that between 2 and 18 pounds of slfur trioxide were released.	The CP plant was shut down. The oleum flow was stopped within 3 minutes and the liberation of sulfur trioxide within 15 to 20 minutes.	Initially a level 1 called into agencies. A level 2 was called at the close of the event.
Tesoro Golden Eagle Refinery January 12, 2005	Visible emissions of steam and coke dust from No. 5 Boiler Stack due to	Boiler was shutdown.	Tesoro received 2 complaints from the community for the visible emission. Odor

January 12, 2005	Boiler Stack due to tube failure.		visible emission. Odor patrol indicated theat there were no odors in the surrounding communities (Concord, Vine Hill, Benicia Bridge, and Martinez areas)
ConocoPhillips October 31, 2004	Plant 19, F-1 flare gas knockout drum line 14 inch flange was opened while process gases were flowing, instead of another flare line flange that emptied and suppose to be opened.	Release of process gases and plant emergency called.	Hydrogen sulfide and reduced sulfur compounds were released that caused strong odors downwind. Complaints about strong odors came from as fay away as Bay Point. Sirens were sounded and the residents of Crockett and Rodeo were asked to shelter-in-place.
Tesoro Golden Eagle Refinery October 30, 2004	No 5 boiler pluming during start-up of the coker unit after the turnaround.	Operational upset during coker start-up and ultimate shutdown.	Visible black plume, signigicant pluming of coke dust. Tesoro rec'd one complaint, BAAQMD rec'd five compliants.
Tesoro Golden Eagle Refinery October 14, 2004	Fire at a naphtha transfer pump at 2:45 A.M. At 5:30, the fire is no longer visible and at 6:27 CCHS declares the incident to be "all clear."	Fire response personnel were able to isolate tank from the pump.	Visible black plume, no odor complaints received by BAAQMD or CCHS. IH detected no chemicals of concern off-site.
Tesoro Golden Eagle Refinery September 16, 2004	Explosion and fire within Tank 745 at 12:03 A.M. The Tank contains sulfuric acid and a floating layer of alkylate. Fire was out at 6:56. CO2 was introduced to tank at 6:42.	Sulfuric acid recycling unit was shutdown.	50' to 100' flames, smoke plume straight up, no odor complaints received by BAAQMD or CCHS, one odor report received by Tesoro. IH detected no chemicals of concern off-site.
Tesoro Golden Eagle Refinery	#5 boiler developed an internal water	#5 boiler shutdown, coker	Visible black plume containing coke dust.

July 4, 2004	leak at app.1:42 p.m. and coker flue gas was then diverted directly to the stack.	and crude rate reduced.	
General Chemical Bay Point Works April 3, 2004	Fire at a storage hangar near packaging building. The fire involved several pallets of chemicals (hydrogen peroxide-30%, nitric acid-69%, ammonium hydroxide-29%, misc. etchants), cased in one-gallon bottles, several 55-gallon drums and 8-pallets of empty bottles.	Facility was evacuated.	A plume of smoke was visible for 1-2 hours. Community advisory notice was distributed but not shelter-in-place.
Tesoro Golden Eagle Refinery March 2, 2004	Odor complaints were received at the Golden Eagle Refinery and recognized in the Vine Hill area the evening of March 1. The refinery receive additional odor complaints on March 2. Hundreds of odor complaints were received from Bay Point, Pittsuburg, Concord, Pleasant Hill, Walnut Creek, Alamo, Danville, San Ramon, Dublin, and Pleasant. The odors seemed to have originated from the Golden Eagle Refinery. Tesoro was unable to locate the source of the odors. The odors could have	No noticeable impact onsite.	Hundreds of odor complaints throughout Central and parts of East County from the north part of the County into Alameda County. The odors were consistent with reduced sulfur compounds. CCHS received information that people were feeling ill from the odors and at least case where a person past out.

	originated from some of the areas doing special operations. Tesoro shut down the operations and odors were no longer noticeable.		
Tesoro Golden Eagle Refinery February 20, 2004	Due to problems that occurred at the Foster Wheeler Cogeneration Facility, electrical power was lost at the Golden Eagle Refinery. The refinery shut down and depressured to the flare. This caused incomplete combustion of the flare and large amount of black smoke.	The refinery shut down due to the lack of power and sent large quantaties of hydrocarbons to the flares.	The flare smoking caused concerns to the community. The smoke in most part was going straight up with some smoke drifting over North Concord.
Chevron Richmond Technology Center September 16, 2003	Fire at the Tank field (Oronite Drum loading) at 12:41 p.m. While discharging gasoline from a tank truck to 55 gallon drums via a manifold system an ignition occurred in a partially filled drum. Flames quickly spread to the tops of adjacent drums and eventually caused the breach of several drums. It is reported that the Operator and Truck Driver activated the shutdown systems as they evacuated the area.	Heat blistered paint on one 60,000 gallon tank in the nearby tank farm area. $150,000 of product loss (400 gal) and equipment damage.	Black smoke until the fire was extinguished by CFD.
Chevron	North Isomax	Shutdown N	Odor complaint, 26

Chevron August 9, 2003	North Isomax plant hydrogen recycle compressor, K600 unexpectedly shut down resulted in flaring activity with visible smoke.	Shutdown N. Isomax.	Odor complaint, 20 persons sought medical attention at Richmond Kaiser.
Tesoro June 8, 2003	The #5 Boiler developed an internal water leak sufficient to compromise good boiler water level contro. #5 Boiler fuel (waste heat from coker) was then diverted directly to the stack, and #5 Boiler was shutdown. When this occurs coke fines go out the stack. Coke fines continued to go out of the stack from 2200 6/8 to 0600 hours 6/10. It is estimated that 3.4 tons of coke fines went to atmosphere.	The refinery is at reduced production, until the #5 boiler is brought back online or temporary boilers can come online.	Coke fines were sent to the atmosphere. Complaints of rotten egg and burnt match spells were received.
Shell Martinez Refinery January 11, 2003	The Flexicoker Unit had a small fire starting about 3pm on 1/11/03. The fire may have involved gas oil or a heavy oil stream. One of the Safety Supervisors thought the smoke was traveling off-site so the bumped it to a level 3, including sirens and a scroll across the TV. Wayne was told that the scroll did not work so well since it blacked out the	Small fire, smoke.	Smoke potentially traveling offsite. Level 3. Sirens sounded. TV warning message scrolled.

	football game, instead of just scrolling. Paul Andrews responded by telephone and was interviewed by the press. Wayne said that Paul informed the press that Shell conservatively went to a level 3. Shell started their incident investigation, including the RCA over the weekend. Art Kinney is leading the investigation.		
General Chemical-Richmond September 26, 2002	SO3 release from CP unit, control valve problem, prompting Level 2.	Unit shutdown.	Plume toward Chevron.
Phillips (now ConocoPhillips) Rodeo, CA July 10, 2002	The steam boilers were tripped off, which led to a loss of steam for the refinery. The refinery was shutdown immediately with much of the offgas going to the flares. The flares were overwhelmed and created a lot of smoke and decreased the overall efficiency of the flares.	The refinery lost steam and had an emergency shutdown.	Smoke, partial burned hydrocarbons, and sulfur compounds impacted the communities downwind. Tormey and Crockett were asked to shelter-in-place. Sirens and the CAN were activated.
Shell Martinez, CA April 23, 2002	Sulfur Recovery Unit #3 was being shut down on the morning of 4/23/02 to address concerns about	Shutdown SRU#3 pending outcome of investigation and completion of RCA.	Smoke released. Level 3 was called with sirens activated. CCHS identified that visible smoke plume stayed elevated and

		SO_2 stack emissions, which were approaching the BAAQMD 250 ppm/hr limit. SRU#3 converts acid gas consisting of SO_2 and H_2S to elemental sulfur in a catalytic reactor utilizing the "Claus" process. The SRU#3 vent gas is routed through a Shell Claus Offgas Treatment (SCOT) plant for additional treatment. The SCOT-3 vent gas is routed through a catalytic oxidizer to convert remaining H_2S to SO_2. By 11am all acid gas feed had been removed from SRU#3. Approximately an hour later, at 12:15 p.m. the catalytic oxidizer experienced a temperature excursion (most likely resulting from burning sulfur), which led to a plume from the SCOT-3 stack by 12:30 p.m. At 12:30 p.m., Shell called the incident a Level 1. At 12:35am, the Shell IC upgraded the incident to a CWS Level 3 and sounded sirens. Steam and nitrogen were used to cool the catalytic oxidizer. CCHS field observations identified black	dissipated quickly. Event was over very quickly.

	identified black plume, which dissipated very quickly and no plume was visible after about 10 or 15 minutes. Shell secured the unit at 12:57 p.m. CCHS called the official "All Clear" at 1:21 p.m.		
Loctite Bay Point Pittsburg, CA February 21, 2002	Considerable smoke was released from a 55-gallon drum containing intermediate adhesive product (epoxy resin). The smoke was caused by an exothermic runaway reaction (Monkey) that occurred due to addition of excessive hardener to the drum.	Drum moved from manufacturing area to outside.	Smoke released. Level 3 was called with sirens activated. People living downwind were asked to shelter-in-place.
Chevron Richmond, CA January 31, 2002	Release of sulfur dioxide from the #3 SRU plant. A high vapor/liquid flow condition was created by the Isomax #4 H2S plant when a normal heat exchanger backwash was being performed, which caused an interlock plant shutdown at #3 SRU. The momentary release occurred while restarting the plant.(Level 3 initiated by CCHS.)	Shutdown Isomax and the #3 SRU.	A few calls were reported to the facility expressing concern or inquiring as to the activity taking place. People in Richmond were asked to shelter-in-place.
Ultramar	Release of sulfur	Shutdown their	No measurable

(now Tesoro) Martinez, CA January 26, 2002	trioxide from the acid plant was released. A malfunction of the sonic meter system to measure concentration of 99% H2SO4. The acid became super saturated with sulfur trioxide, and the sulfur trioxide was released out of the stack.	acid operations.	quantities of sulfur trioxide or sulfur dioxide were measured offsite. Sirens and CAN was activated. People in Clyde and North Concord were asked to shelter-in-place.
General Chemical Richmond, CA November 29, 2001	The 99.5% sulfuric acid concentration was super saturated, which caused a release of sulfur trioxide.	The plant was starting up. Shut down the plant.	Sulfur trioxide and sulfur dioxide went offsite and a Level 3 was called. Sirens were activated. People from the communities downwind were asked to shelter-in-place.
Equilon (Now Shell) Martinez, CA October 17, 2001	Cat cracker release of soot, catalyst, and hydrocarbons during another catalytic cracking unit upset (same unit as 10/14, 2001 incident). More than 50,000 lbs hydrocarbons emitted.	Cat cracker unit shutdown to do a full investigation. Unit was down for 2 months.	Mostly hydrocarbons were released. A Level 3 was called with sirens and CAN being activated. The people in the community downwind were asked to shelter-in-place. Interstate 680 was shutdown for most of the duration of the release. Numerous calls from community.
Equilon (Now Shell) Martinez, CA October 14, 2001	Cat cracker release of soot, catalyst, and hydrocarbons during catalytic cracking unit upset. More than 5,000 lbs hydrocarbons emitted.	Cat cracker was starting up and had to discontinue the startup.	Soot dusted the Martinez area that is north of the refinery. Odors were smelled over a mile north of the refinery. Level 3 was called with sirens being sounded. CAN was not used, since the incident was over before CAN could be used.
Equilon (Now Shell) Martinez, CA	An upset occurred in the straight run hydrotreater unit	Unit upset resulting in unit shutdown. One	Smoke and hydrocarbons released. Level 3 was called with

Martinez, CA July 18, 2001	hydrotreater unit in the light oil processing area. Subsequently, fires occurred in the vacuum flasher heater furnace and crude unit heater furnace. Hydrocarbons, H2S, and smoke released offsite. Level 3 under CWS, sirens activated.	shutdown. One MRC emergency responder slightly injured when a fire truck fitting struck his leg.	Level 3 was called with sirens activated.
General Chemical Richmond, CA May 1, 2001	Truck hit a power line and GCC lost power. A release of sulfur dioxide occurred when the decomposition chamber went positive.	The plant shutdown and had problems when starting up. Another release occurred.	Sulfur dioxide went offsite and a Level 3 was called. Sirens and CAN were activated. People were asked to shelter-in-place downwind of the plant.
MBA Polymers Richmond, CA October 26, 2000	MBA Polymer recycles plastics from computer components. They cut the plastics and fines are collected in a vent system. The dust from the cutting operation is believed to have found an ignition point and a dust explosion and a fire occurred.	One worker was killed and four others injured. The initial concern was a fire, since there is very little hazardous materials handled at the site. The concern was that the by-products of the fire was toxic and when the wind shifted and was going in the direction of a residential area sirens were sounded and telephone calls were made. One employee was killed and there was major impact to the building.	Because smoke was impacting the community. Sirens and telephone calls were made after the wind shifted and there was a concern that the smoke was going into the neighborhood.

Tosco (now Tesoro) Avon, CA June 6, 2000	A fire at the coker unit. Naphtha was released from the flushing oil tank and caught on fire.	The #5 Boiler was shutdown. Two contractors had minor injuries.	Smoke from the fire was visible offsite. With the #5 boiler offline, particulates were released into the air from the stack.
Tosco (now Tesoro) Avon, CA March 22, 2000	A fire occurred at the alkylation unit. A contractor was welding in the alkylation unit with a fire watch spraying down any errant sparks. The firewater caught on fire because flammable hydrocarbons backed into the fire waterline.	Two contractors were injured.	None.
Tosco (now ConocoPhillips) Rodeo, CA February 7, 2000	Catacarb leak and hydrogen fire at the unicracking unit. The fire lasted approximately 10 minutes. Localized corrosion caused a pipe to fail and dumped the Catacarb from the unit and then hydrogen was released and ignited.	Unit shutdown loss of the supply of Catacarb.	Smoke visible offsite.
Tosco (now ConocoPhillips) Rodeo, CA January 15, 2000	Flaring from the MP-30 ground flare for approximately 2 hours. The low level point in the header caused the flaring.	Unit shutdown.	Black smoke visible offsite.
Tosco (now ConocoPhillips) Rodeo, CA December 16, 1999	Overpressure of the flare header system where the MP-30 ground flare was used. There was a low point in the flare header that	Unit shutdown.	Black smoke that could be seen as far away as Emeryville. People in Rodeo were asked to shelter-in-place.

	accumulated liquids.		
Chevron Richmond, CA March 25, 1999	Isomax fire that required the sounding of sirens. A valve stem blew out that caused a release of hydrocarbons and hydrogen sulfide that ignited, resulting in a major fire.	Shutdown a major part of the refinery - two people slightly injured fighting the fire.	Smoke was visible over much of the North Bay Area - Disruption in traffic - Sirens sounded, people were asked to shelter-in-place.
Tosco (now (now Tesoro) Avon, CA February 23, 1999	50 crude unit flash fire killing 4 people and seriously injuring another.	The shutdown of 50 crude and then later the shutdown of the whole refinery. Four people died with another seriously injured.	None.
Tosco (now ConocoPhillips) Rodeo, CA April 23, 1997	An upset in the distillation unit sent hydrocarbons to the sulfur recovery units. The sulfur recovery units released hydrogen sulfide.	Shutdown parts of the refinery until the problem was found and the different units were stabilized.	People were asked to shelter-in-place in Tormey and Crockett.
Tosco (now Tesoro) Martinez, CA January 27, 1997	A hydrocracker had a run away reaction that raised the temperature and pressure of the outlet gases. An outlet pipe failed and caused an explosion and fire. One worker was killed and forty-six people sought medical attention.	One worker was killed and forty-six other sought medical attention. Many of the people seeking medical attention were injured while running away from the explosion and fire. The outlet piping and some of the equipment and instrumentation was damaged. The	There was little of no offsite impact from this explosion and fire. People were not asked to take any protective action, such as sheltering place.

		The hydrocracker unit was shutdown until the unit could be repaired.	
Unocal (now ConocoPhillips) Rodeo, CA May, 1996	A hot coke drum was dumped and a fire was initiated.	Fire damage to the coker unit. The coker unit was run at partial capacity until repairs could be made.	People were asked to shelter-in-place in Tormey and Crockett. A few people in Vallejo sought health care assistance complaining of the smoke and odors.
Shell Martinez, CA April 1, 1996	Fire at their cracked gas unit. The fire lasted for over 3 hours.	Fire damage was extensive onsite. The unit was shutdown until repairs could be made.	People were asked to shelter-in-place downwind of the refinery. The smoke from the fire impacted the area downwind.
Air Products Martinez, CA February 1, 1996	Piping failed because of corrosion and a release of hydrogen occurred with an explosion. The fire lasted approximately 10 minutes.	Shutdown of the hydrogen unit.	Noise of the explosion was heard offsite for well over a mile. Some minor damage offsite.
Unocal (now ConocoPhillips) Rodeo, CA June 16, 1995	Tank fire that continued to burn off and on for approximately 1 week.	Response from the facility along with the local fire departments.	Smoke impacted the communities of Crockett, Rodeo, CA and Tormey. The communities were asked to shelter-in-place. Odors lingered in the communities for a week after the fire. Unocal put up approximately 100 people in motels until the incident was 100% secure.
Unocal (now ConocoPhillips) Rodeo, CA	A column used to strip carbon dioxide developed a leak. The column continued to	The Catacarb® affected the health of many of the workers downwind of	The release impacted the communities of Crockett, Rodeo, CA and Tormey. Many homes and cars were

August 22 - September 6, 1994	continued to operate for a 16-day period. The hole in the column became larger where a solution of Catacarb® was atomized and released. Estimates of between 80-225 tons of Catacarb® was released.	downwind of the column. At the end, the hydrocracker processing unit was shutdown.	homes and cars were cleaned to remove the Catacarb® solution. A health clinic setup by Unocal in Crockett treated over 1200 people over the next year. Some people are still complaining of health effects from the release.
General Chemical Richmond, CA July 26, 1993	Overheating of a tank car of 35% oleum that released between 4 and 8 tons of sulfur trioxide over a three hour and forty-five minute period. The sulfur trioxide formed a sulfuric acid cloud.	The loss of a tank car of 35% oleum and the shutting down of their processing.	Over 22,000 people sought medical assistance with 15-22 people staying in the hospital overnight. People were asked to shelter-in-place downwind of the release.
Rhône Poulenc (now Rhodia) Martinez, CA May, 1992	Sulfuric acid mixed with hydrocarbon spill and fire. The fire was difficult to put out because the sulfuric acid would break down the foam used by the fire fighters. One employee was killed and another was seriously injured.	Fire damaged some of the equipment onsite. The man who died and the one who was injured were Rhône Poulenc employees.	Smoke did go offsite and impacted the community. The smoke also included the degradation products of the sulfuric acid (e.g., sulfur trioxide, sulfur dioxide). Shelter-in-place was called for the community downwind of the fire.

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Production and processing of sour crude and natural gas - challenges due to increasing stringent regulations

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Petroleum Engineering
Submission date: June 2013
Supervisor: Jon Steinar Gudmundsson, IPT

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Abstract

The worldwide demand for petroleum is growing tremendously. It is expected that the demand will have incremental capacity of 20 mb/d for crude oil, reaching 107.3 mb/d, and demand for natural gas will rise nearly 50% to 190 tcf in 2035, compared to 130 tcf now. According to the International Energy Agency 70% of crude oil reserves and 40% of natural gas reserves are defined as having high content of organosulfur compounds. Obviously, for decades to come, to satisfy the growing global needs for fossil fuels, reservoirs with sour contaminants will be developed intensively.

The sulfur compounds in crude oils and natural gas generally exist in the form of free sulfur, hydrogen sulfide, thiols, sulfides, disulfides, and thiophenes. These compounds can cause considerable technical, environmental, economic, and safety challenges in all segments of petroleum industry, from upstream, through midstream to downstream.

Currently, the sulfur level in on-road and off-road gasoline and diesel is limited to 10 and 15 ppm respectively by weight in developed countries of EU and USA, but this trend is now increasingly being adopted in the developing world too. Furthermore, it has to be expected that the sulfur level requirements will become more and more strict in the foreseeable future, approaching zero sulfur emissions from burned fuels.

The production of ultra low sulfur automotive fuels has gained enormous interest in the scientific community worldwide. Oxidative desulphurization, biocatalytic desulphurization, and combined technologies, which are alternatives to conventional hydrodesulphurization technology, are much more efficient and more economical in removing complex sulfur compounds, especially benzothiophene, dibenzothiophene and their alkyl derivatives.

Keywords: *product quality specifications, H_2S corrosion, hydrodesulphurization, biocatalytic desulphurization, oxidative desulphurization*

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1. Introduction

Fossil fuel-based hydrocarbons are a primary energy source for current civilizations, which nowadays accounts for 83% of global energy consumption, and this tendency is forecasted to continue even after two decades (Pratap, 2013). However, to satisfy such rapidly growing appetite for fossil fuels, the petroleum industry will have to face a lot of challenges. Oil and gas companies, which have always preferably produced the oil and gas from the reservoirs technically the easiest to develop, will have to develop more complex and extremely challenging sour hydrocarbon projects. In the nearest future, crude oil and natural gas with high sulfur content will be the energy source of choice to meet increasing demand.

In order to understand the importance of those challenges thorough analysis of hydrocarbon quality is needed. To start with, it should be that the value of the reservoir fluid is commonly based on its quality characteristics. Lower quality Dubai crude is sold at discount rate to lighter, sweeter Brent crude. Sulfur content is among the most important characteristics of the crude oil and natural gas. Currently, there is a negative trend of increase of sulfur content in hydrocarbons worldwide. If US sulfur content of crude oil input to refineries was 0.88% in 1985, as of February 2013 it was 1.44% (EIA, 2013).

Another unfavorable for refineries tendency regards to environmental sulfur regulations. If in 2012 the maximum allowable level of sulfur was 795 ppm in Africa, 605 ppm in the Middle East, 520 ppm in Latin America, in 2030 it is expected to decrease the sulfur content to 95 ppm, 16 ppm, and 30 ppm respectively. The other nations of the world are moving towards environmentally friendly transportation fuels too. New transportation fuel specifications are being put into effect worldwide. As a result, those contradirectional factors, such as hydrocarbon quality deterioration and reducing the maximum allowable level of sulfur, are making the situation even worse.

However, before considerable investment will be put in completely new technologies and tools, the industry has to deal with existing problems. There are number of technical, economical, and environmental problems. All of them are caused by the presence of organosulfur compounds in petroleum. They are very undesirable, because of their actual or potential corrosive nature, disagreeable odor, deleterious effect on color or color stability, and unfavorable influence on antiknock and oxidation characteristics. Furthermore, sulfur compounds poison expensive refining catalysts and pollutes into the atmosphere in a form of sulfur oxides when burned, causing environmental problems. Emissions of sulfur compounds formed during the combustion of petroleum products are the subject of environmental monitoring in all developed countries.

Crude corrosivity problems have been studied since 1950's mostly because of their severity and economic impact on production and refining operations. To date the annual cost of corrosion worldwide is estimated at over 3% of GDP of the planet, which is literally 3.3$ trillion. Without taking into account the progress made in understanding the role of different parameters on the corrosion process, modern scientific society cannot give exact answers in understanding and prediction of petroleum corrosivity.

Hydrocarbon producing companies in order to meet the stringent environmental and safety requirements are in search of "green" and cost-effective methods for desulphurization of crude oil and natural gas. Desulphurization is costly technology and petroleum refiners could spend 25 billion USD over the next decade (Monticello, 1996). Commonly used conventional desulphurization technology - hydrodesulphurization - is expensive and does not efficiently handle sulfur removal in a number of situations. Hence, other efficient desulphurization technologies, as biocatalytic desulphurization, oxidative desulphurization are being used in test scale and commercial scale projects.

The main purpose of this master thesis is to analyze the rising sulfur problem and outline the needs for better technologies to remove the sulfur. The analysis has been done based on annual energy reviews, from different sources, such as OPEC, BP, EIA, and others. The origin and the types of sulfur present in hydrocarbons are studied. Also commercial, semi-commercial, and test scale desulfurization technologies are reviewed.

2. World petroleum reserves

British Petroleum defines the term proved reserves of crude petroleum as those quantities of petroleum that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions (BP, 2012).

As of January 2013, the estimated world proved reserves of crude petroleum were 1.6 billion barrels. OPEC currently accounts for 73.6% of total world oil reserves. Venezuela with its heavy, sour crude holds the largest share of the world's petroleum reserves at 18% of the total, as a result of recent reserves identified in this country. Other countries with the biggest crude oil reserves are Saudi Arabia (16.2%), Canada (10.6%), Iran (9.4%) and Iraq (9.6%) (Table 20).

On a regional basis, the Middle East accounts for nearly 48% of the world's reserves. Central and South America is second with 20%, following recent reserves identified in Brazil and Venezuela, and North America is third with 13% (Figure 1).

The International Energy Agency (IEA) estimates that 70% of the world's remaining oil reserves consist of heavy, high sulfur crude. Moreover, there is a common tendency in all big discoveries found in the last 30 years. The crude from these new oil fields tends to be heavy, difficult to extract, with high sulfur content. One of the reasons of crude oil quality deterioration is depletion of production from conventional, commonly sweet reservoirs. This trend can be seen by looking at the history of crude oil production, which is now extending over more than 150 years (Zittel & Schindler, 2007):

- Virtually all the world's largest oil fields were all discovered more than 50 years ago;
- Since the 1960s, annual oil discoveries tend to decrease;
- Since 1980, annual consumption has exceeded annual new discoveries;
- Till this day more than 47,500 oil fields have been found, but the 400 largest oilfields (1%) contain more than 75% of all oil ever discovered;

When it comes to natural gas proved reserves the Middle East and Europe & Eurasia region account for 75% of whole world's reserves (Figure 2). In fact, 40% of the world's natural or associated gas reserves currently identified as remaining to be produced, representing over 2600 trillion cubic feet (tcf), are sour, with both H_2S and CO_2 present most of the time. Among these sour reserves, more than 350 tcf contain H_2S in excess of 10%, and almost 700 tcf contain over 10% CO_2 (Lallemand et al., 2012).

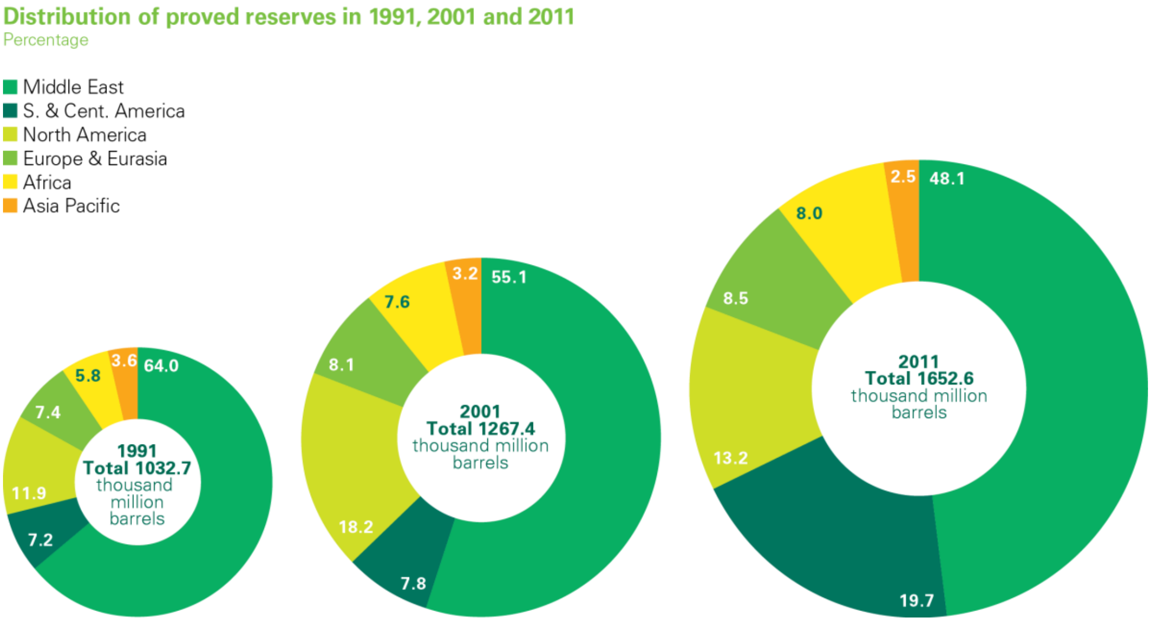

Figure 1 *Distribution of proved reserves of crude oil in 1991, 2001 and 2011 (BP, 2012)*

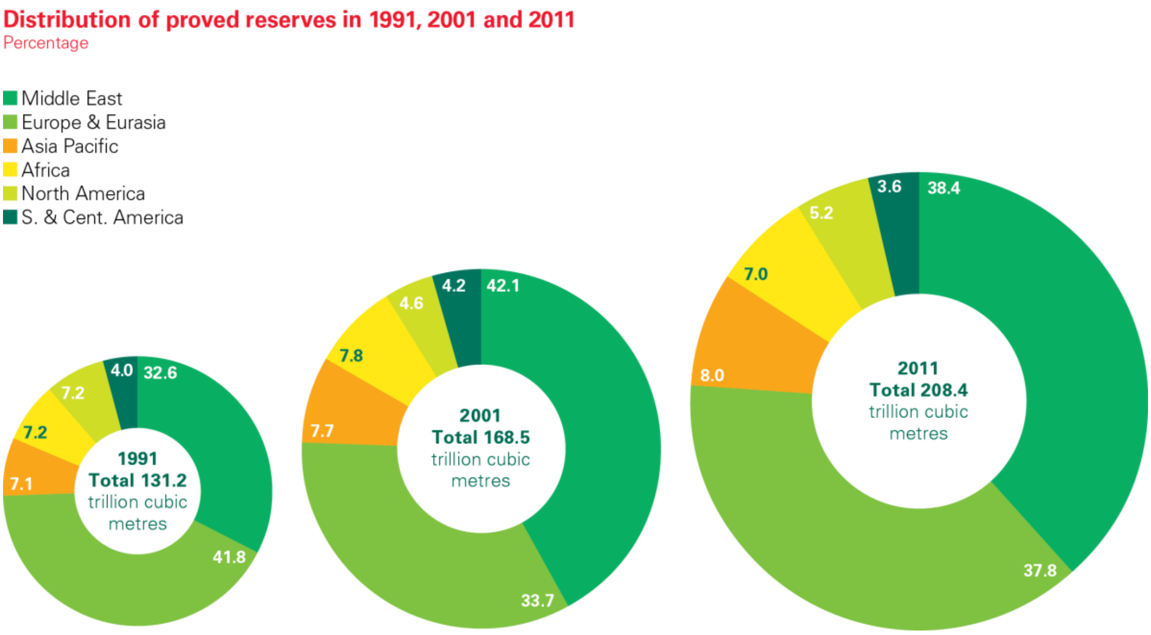

Figure 2 *Distribution of proved reserves of natural gas in 1991, 2001 and 2011 (BP, 2012)*

3. Petroleum supply and demand outlook

Worldwide crude oil production is forecasted to increase to meet the growing consumption, at the same time the sources of growth will change the global balance. Global crude oil supply is set to rise by about 16.5 Mb/d by 2030. 75% of the global supply growth will be accounted to OPEC. Crude supply decline from Europe, Asia Pacific, and North America is expected to offset by growth in deepwater Brazil and the FSU (BP, 2011).

Non-OPEC output will rise by nearly 4 Mb/d. Unconventional supply growth should more than offset declining conventional output, with biofuels adding nearly 5 Mb/d and oil sands rising by nearly 2 Mb/d (BP, 2011).

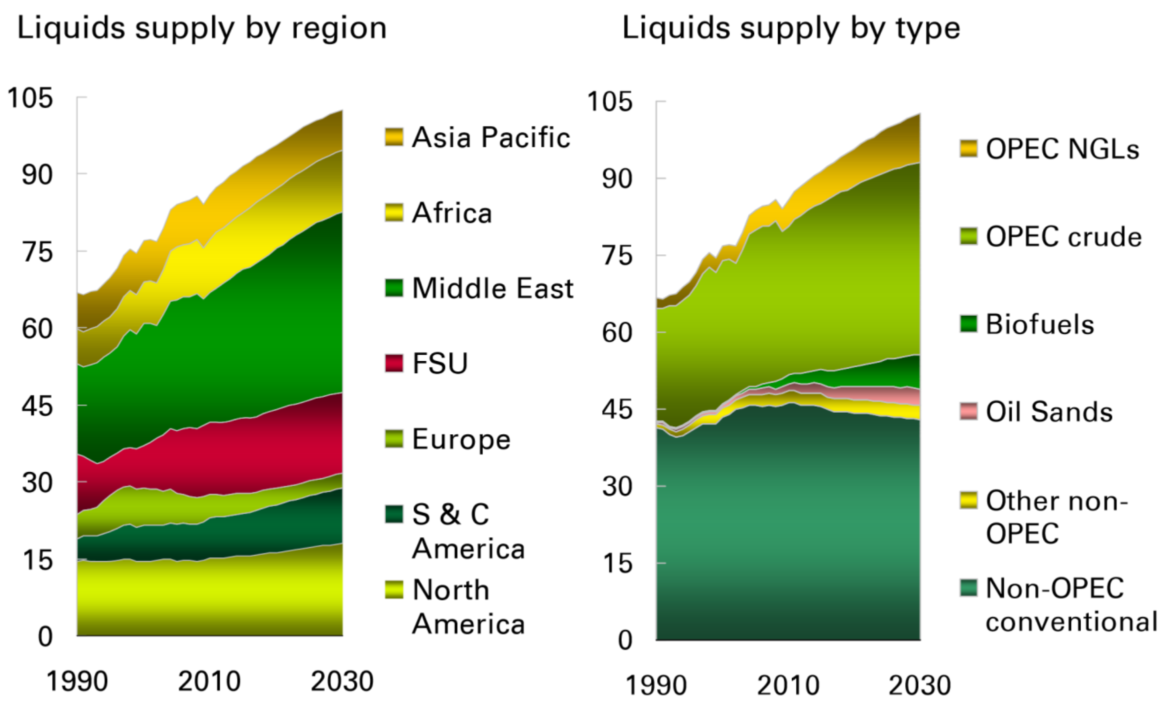

Figure 3 *Worldwide petroleum liquids supply outlook (BP, 2011)*

The global crude oils demand is also predicted to increase, but growth slows to 0.8% p.a. (from 1.4% p.a. in 1990-2010 and 1.9% p.a. in 1970-90). The OPEC is forecasted the demand for crude oil for long-term period from 2010 to 2035. The outlook for oil demand is shown in Table 1. In the forecasting period of 25 years demand will have an incremental capacity of 20 mb/d, reaching 107.3 mb/d by 2035. 87% of the increase in crude oil demand in developing Asia, whereas OECD demand shows a steady decline, as it was already peaked in 2005 (OPEC, 2012). Non-OECD consumption is likely to overtake the OECD by 2014, and reach 66 Mb/d by 2030.

***Table 1** World oil demand outlook (mb/d) (OPEC, 2012)*

	2010	2015	2020	2025	2030	2035
OECD America	24.1	23.7	23.5	23.0	22.4	21.7
OECD Europe	14.7	13.7	13.4	13.0	12.6	12.1
OECD Asia Oceania	8.1	8.4	8.2	8.0	7.6	7.3
OECD	**46.8**	**45.8**	**45.2**	**44.0**	**42.6**	**41.1**
Latin America	4.9	5.4	5.8	6.1	6.4	6.6
Middle East & Africa	3.3	3.8	4.1	4.5	4.8	5.1
India	3.3	4.0	4.9	6.0	7.4	9.0
China	9.0	11.1	13.2	15.0	16.4	17.6
Other Asia	6.8	7.5	8.4	9.1	9.7	10.3
OPEC	8.1	9.0	9.8	10.6	11.4	12.0
Developing countries	**35.4**	**40.8**	**46.3**	**51.3**	**56.0**	**60.6**
Russia	3.2	3.5	3.6	3.6	3.6	3.6
Other Eurasia	1.6	1.7	1.8	1.9	2.0	2.1
Eurasia	**4.8**	**5.2**	**5.4**	**5.5**	**5.6**	**5.6**
World	**87.0**	**91.8**	**96.9**	**100.9**	**104.2**	**107.3**

The transportation sector is a key to future oil demand growth. OECD consumption will fall to 40.5 Mb/d. Figure 4 shows the increasing tendency in oil consumption in road transportation. It can be easily seen that by 2020, non-OECD oil use in road transportation (nearly 14 Mb/d) will be greater than in the OECD. Furthermore, the majority of this increase will be dominated by developing Asian countries, especially China and India.

Demand for natural gas will rise nearly 50% to 190 tcf in 2035, compared to 130 tcf for now. Gas demand in the forecasting period will be mainly driven by non-OECD countries, with growth averaging 3% p.a. to 2030 (Figure 5). On the top of the demand growth is non-OECD Asia (4.6% p.a.) and the Middle East (3.9% p.a.). Of the major sectors globally, growth is fastest in power (2.6% p.a.) and industry (2% p.a.) which matches with historic patterns., Compressed natural gas use in transport is confined to 2% of global transport fuel demand in 2030, with threefold increase from today's level (BP, 2011).

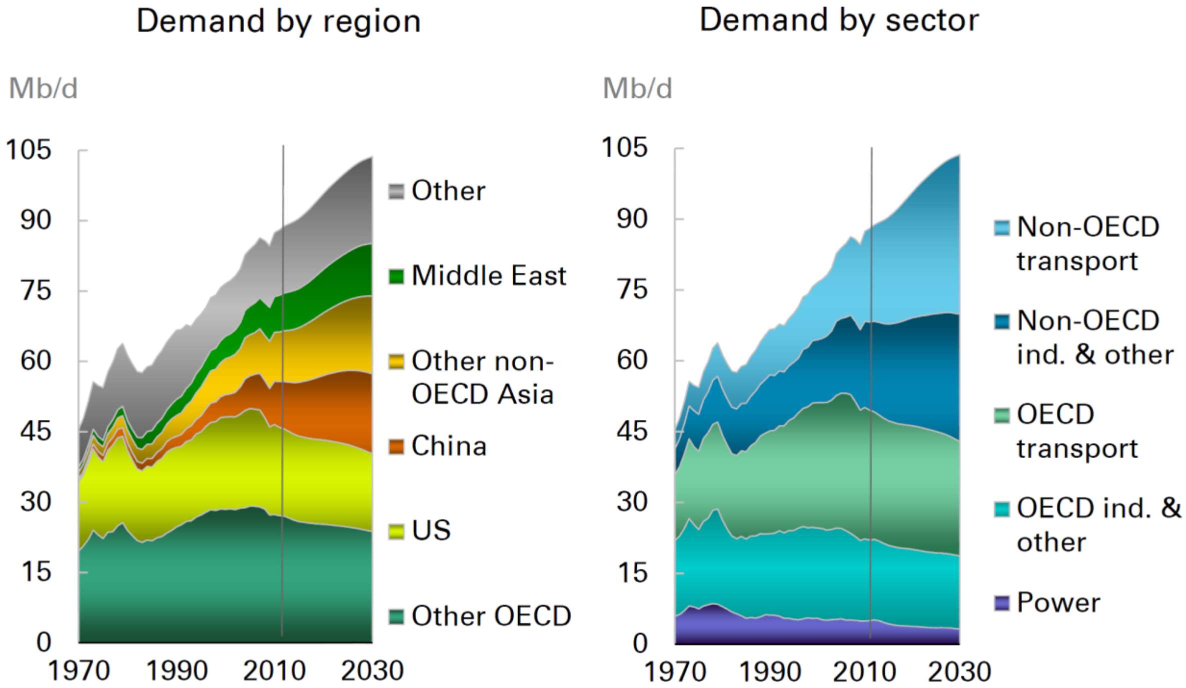

Figure 4 *Worldwide petroleum liquids demand outlook 1970-2030 (BP, 2013)*

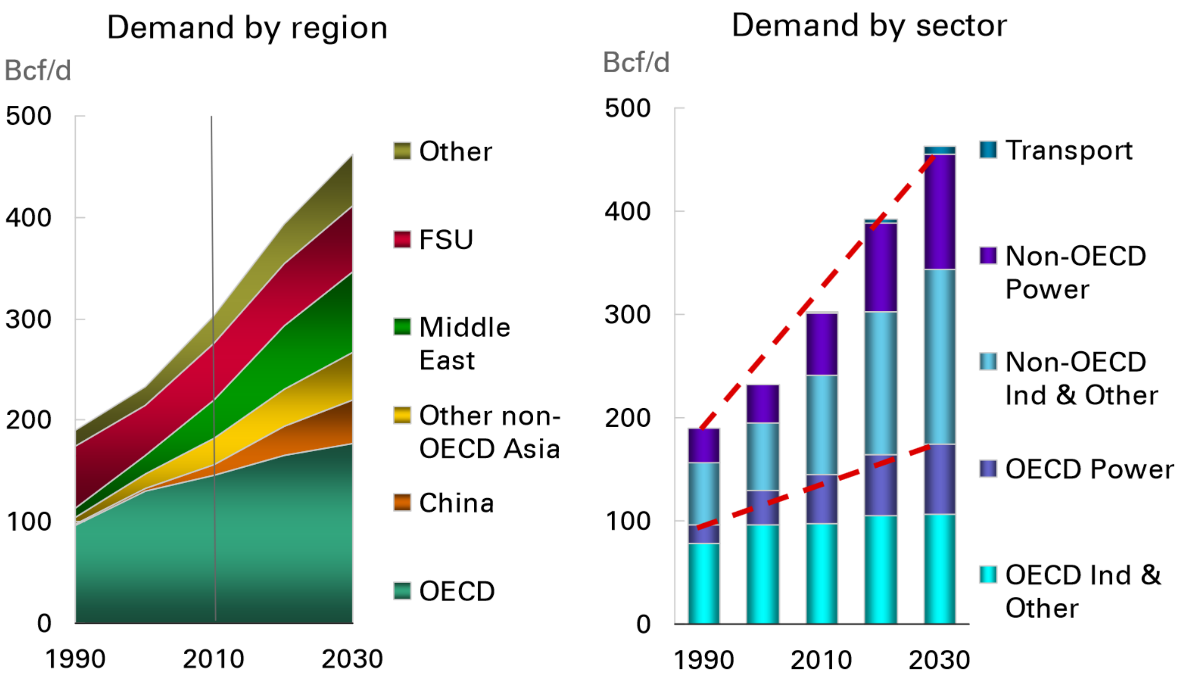

Figure 5 *Worldwide gas demand outlook 1990-2030 (BP, 2011)*

4. Crude quality outlook

4.1 Density and API gravity of crude oil

Crude oil quality is measured in terms of density and divided into four groups such as light, medium, heavy and extra heavy crudes (Figure 6). Those groups are defined depending on the value of degrees API. Density in degrees API is a unit of measurement of oil density, developed by the American Petroleum Institute. Measurement of degrees API allows us to determine the relative density of oil to the density of water at the same temperature of 15.6 degrees Celsius. The API degree is found with the following formula:

$$API = \frac{141.5}{SG} - 131.5$$

The SG stands for specific gravity or relative density, which is equal to the density of the substance divided by the density of water (density of water is 1000 kg/m^3). So if the API gravity is greater than 10, then the oil is lighter and floats on water, and if less than 10, then drowned (Wikipedia, 2012). API gravity was designed so that most values would fall between 10° and 70° API gravity (Schlumberger, 2012).

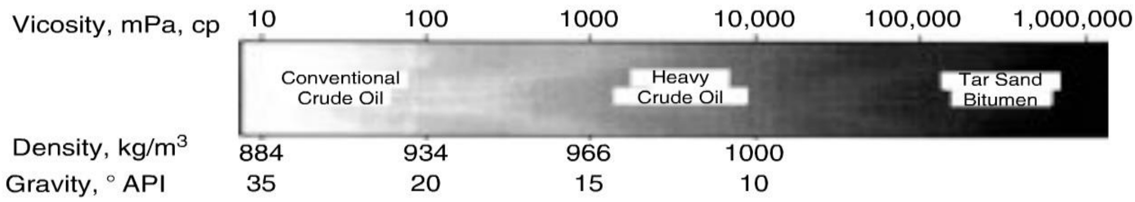

Figure 6 *Classification of petroleum, heavy oil, and bitumen by API gravity and viscosity (Speight, 2007)*

Depending on API gravity crude oils are classified as follows (Figure 6):

- Light: API>31.1
- Medium: 22.3<API<31.1
- Heavy: API<22.3
- Extra heavy: API<10.0

4.2 Sweet and sour crude oil

Depending on the amount of sulfur the crude oil can be sweet or sour. When the total sulfur level in the oil is less than 0.5 % the oil is called sweet and if it is more than that the oil is called sour. Sweet crude oil is more preferred by refineries as it contains valuable chemicals which is needed to produce the light distillates and high quality feed stocks.

Historically, early prospectors tasted the crude oil to determine its quality. Crude petroleum had a sweet taste and pleasant smell if the content of sulfur was low. For this reason, sweet crude is a low sulfur crude oil (FSU, 2010).

Sweet crude is easier to refine and safer to extract and transport than sour crude. Because sulfur is corrosive, light crude also causes less damage to refineries and thus results in lower maintenance costs over time.

Major locations where sweet crude is found include the Appalachian Basin in Eastern North America, Western Texas, the Bakken Formation of North Dakota and Saskatchewan, the North Sea of Europe, North Africa, Australia, and the Far East including Indonesia.

Table 2 *Quality levels - API gravity and sulfur content (Eni, 2012)*

Crude Oil Class	Property Range	
	Gravity (ºAPI)	Sulfur (wt. %)
Ultra Light	>50	<0.1
Light & Sweet	35-50	<0.5
Light & Medium Sour	35-50	0.5-1
Light & Sour	35-50	>1
Medium & Sweet	26-35	<0.5
Medium & Medium Sour	26-35	0.5-1
Medium & Sour	26-35	>1
Heavy & Sweet	10-26	<0.5
Heavy & Medium Sour	10-26	0.5-1
Heavy & Sour	10-26	>1

As opposed to sweet crude sour crude is sold at a discount to lighter sweeter grades. Because the sulfur compounds in the crude oils are generally harmful impurities, they are toxic, have an unpleasant odor, contribute to the deposition of resin and in combination with water causes intense corrosion (K-Oil, 2012). Even though it does not restrains the production of inconvenient crude and the data shows that from 1995 to 2011 medium-sour and sour crude has been the major hydrocarbon produced in the world taking about 55 to 60% of whole crude production, which is shown in Table 22.

Major regions with vast sour crude reserves: North America (Alberta (Canada), United States' portion of the Gulf of Mexico, and Mexico), South America (Venezuela, Colombia, and Ecuador), Middle East (Saudi Arabia, Iraq, Kuwait, Iran, Syria, and Egypt).

4.3 Benchmarks of crude oil

The knowledge of commercial value of the reservoir fluid is of vital importance, as petroleum companies is aimed on getting as much profit as possible. The profit is a function of the cost of petroleum. The cost is based on quality characteristics, such as density and sulfur content which are the most important characteristics of the crude. Depending on the chemical composition and the presence of various chemical elements the term benchmark or market crude should be introduced.

The general concept of benchmarking is to classify crude oil based on its quality. The introduction of grading has become necessary due to the different composition of oil as sulfur content, alkane content and the presence of impurities, in addition to where it is located. For the convenience of trade market and to keep the balance between supply and demand typical benchmarks were created. Prices for other crudes are determined by the differentials to benchmarks (K-Oil, 2012). The major crude oil benchmarks are grouped as follows:

(i) West Texas Intermediate (WTI)

West Texas Intermediate is reference crude, which is produced in Texas. The density is about 40° API and sulfur content ranges from 0.4 to 0.5 %. It is mostly used to produce gasoline and therefore that type of oil is in high demand, especially in the United States and China (UP Trading, 2012).

(ii) Brent Blend

Brent is a reference grade of oil from the North Sea. The oil price of Brent is in the basis for the pricing of about 40% of world oil prices from 1971. The word Brent stands for Broom, Rannoch, Etieve, Ness and Tarbat.

(iii) Dubai

Dubai Crude has a gravity of 31° API and a sulfur content of 2 %. It is extracted from Dubai. Dubai Crude is used as a price benchmark because it is one of only a few Persian Gulf crude oils available immediately.

(iv) Tapis Crude

Tapis is the benchmark for light sweet Malaysian crude. The sulfur content is as low as 0.03% and the API gravity is around 45.5. Although this oil marker is not as widely traded as WTI, it is used as a benchmark in Asia (EconomyWatch, 2010).

(v) Bonny Light

Bonny Light is a benchmark for high grade Nigerian crude, with an API of around 36. Due to its very low sulfur content, it corrodes the refinery infrastructure minimally (EconomyWatch, 2010).

(vi) OPEC Basket

OPEC Basket is the pricing data formed by collecting seven crude oils from the OPEC nations (except Mexico). These include Saudi Arabia's Arab Light, Algeria's Saharan Blend, Indonesia's Minas, Nigeria's Bonny Light, Venezuela's Tia Juana Light, Dubai's Fateh and Mexico's Isthmus. This information is used by OPEC to monitor the global conditions of the oil market (EconomyWatch, 2010).

The crude oils represented in Figure 48 are selection of some of the crude oils marketed in various parts of the world. There are some crude oils both below and above the API gravity range shown in the chart (EIA, 2012). Moreover, quality levels as API gravity and sulfur content are presented on Table 23. The classification ranges from ultra-light to heavy and sour and gives the data on daily production.

4.4 Future trends on crude quality characteristics

Crude oil quality, typically measured in terms of API gravity and sulfur content, does, and will increasingly play a major role in determining future refining requirements. Historically, the average quality of crude oil has been declining steadily. Average sulfur content has been increasing considerably and more rapidly than API gravity. And this trend likely to continue for the foreseeable future (MathProInc., 2011).

The detailed analysis on the expected quality changes in oil supply streams with the projection to 2035 are presented in Figures 7 and 8. The figure is projected to improve marginally to around 33.5° API by 2015, from 33.4° API in 2010, and then move back to 33° API by 2035, a level not very dissimilar to the present one. Figure 8 also underscores that the global average for the entire forecast period is anticipated to remain in a fairly narrow range of less than 1° API. Average sulfur content projections are also can be observed (Figure 7). The expected variations in average sulfur content are wider; they are in the range of 10-15% over the 25-year forecast period (OPEC, 2011).

4.5 Product quality specifications

Refined products specification along with quality of crude oil which is used as a feedstock to the refineries another important aspect which significantly influences future downstream investments. In the last 30 years, downstream industry globally has put considerable amount of money in order to meet new petroleum product quality specifications. The very first regulations have affected the lead content in gasoline, and in the middle of 1990s the focus turned to sulfur content in automotive fuel, especially in the most industrialized countries.

The main purpose of those regulations is to yield high quality automotive fuels with sulfur content less than 10 parts per million (ppm). Moreover, regulators want to tighten sulfur content of other refined products, such as fuel oil, marine bunkers and jet fuel.

Some worldwide efforts have already been made to minimize the content of organosulfur compounds in finished products. This can be seen in Figure 49 and Figure 59, which show the global maximum permitted sulfur content in gasoline and on-road diesel fuel, respectively (as of September 2012).

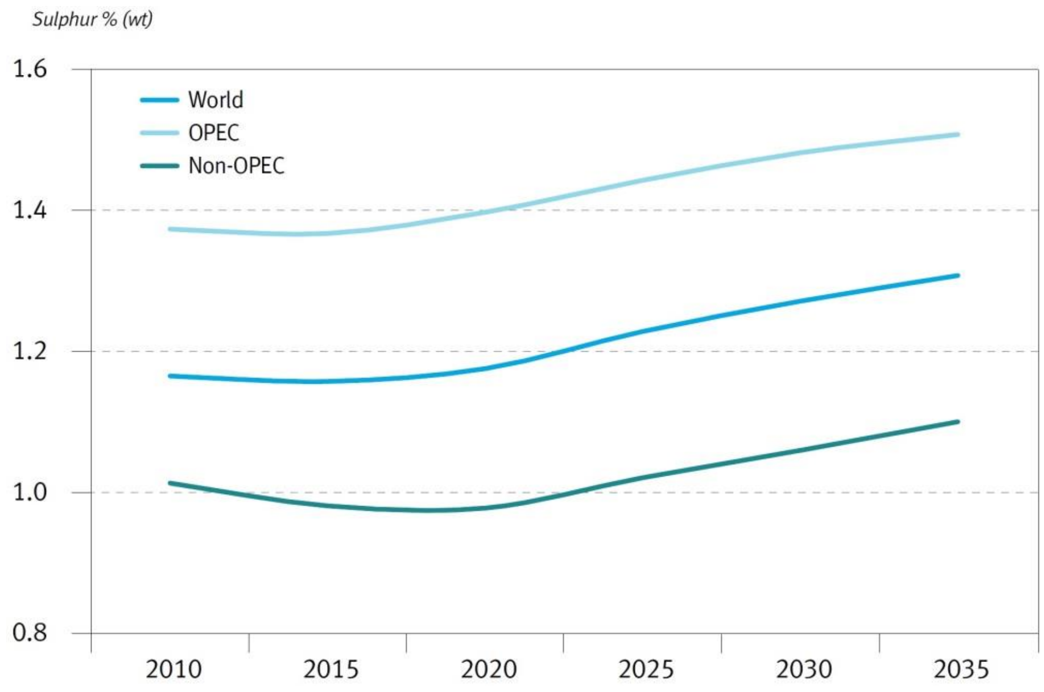

Figure 7 *Crude quality outlook in terms of sulfur content (OPEC, 2011)*

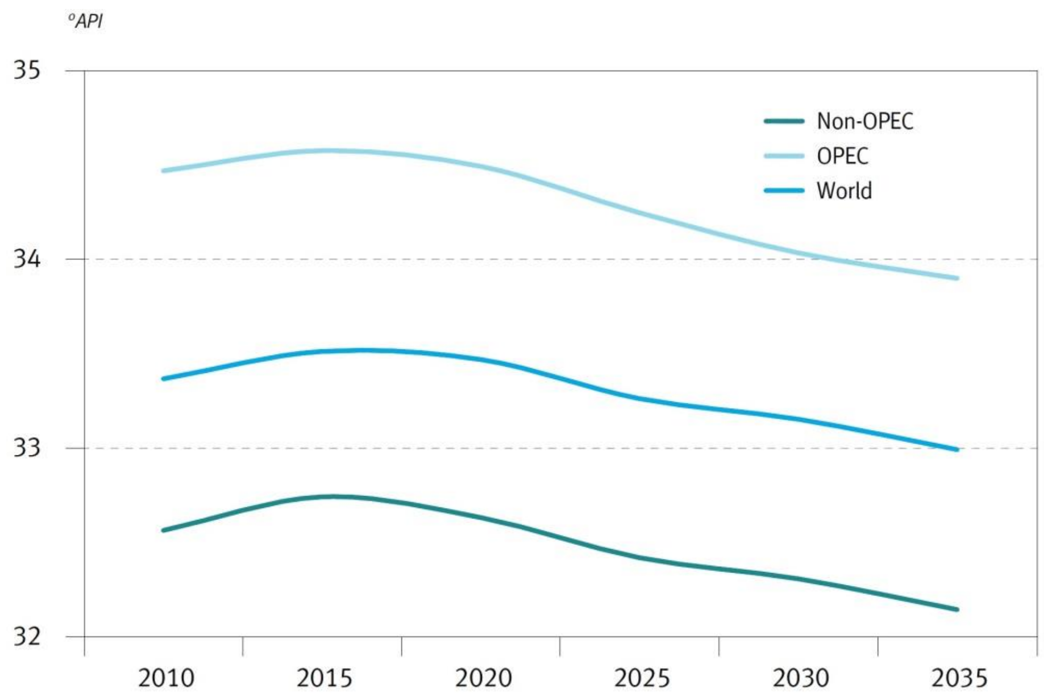

Figure 8 *Crude quality outlook in terms of API gravity (OPEC, 2011)*

However, it should be noted that actual sulfur content levels for products available in specific countries can differ from the ones permitted by regulators (OPEC, 2012).

(i) Gasoline quality specifications

Up-to-date petroleum product quality specifications lay stress upon the extensive use of gasoline with extremely low sulfur content. This tendency is especially noticeable in developed countries; nevertheless developing countries also expect nationwide penetration of low sulfur fuel.

This trend is particularly evident in developed countries, but it is now increasingly being adopted in the developing world too.

In the US the primary plan with its ultra-low sulfur gasoline program was to reduce sulfur to 80 ppm per gallon cap and 30 ppm annual average, as of 2004. Later, in 2010 US regulators have lowered the maximum standard to 30 ppm for all refineries, and California had set even lower specification at 15 ppm.

Since 2005, the EU refineries have produced certain quantities of 10 ppm gasoline together with 50 ppm fuels. As of January 2009, the situation has changed and the maximum allowable sulfur levels were further tightened to 10 ppm.

In China the sulfur limits are regulated on a regional basis. In the cities such as Shanghai, Guangzhou, Shenzhen, Dongguan and Nanjing the maximum sulfur level is set to 50 ppm, in Beijing it is set the strictest fuel quality requirement of 10 ppm, whereas the nationwide sulfur level is adjusted to 150 ppm in 2009. China is expected to lower its nationwide limits to 50 ppm by December 2013 and possibly to 10 ppm by 2016.

Similar tendency can be seen in India. Since 2010, 13 selected cities have lowered the sulfur content to 50 ppm, plus seven more cities since March 2012, whereas the nationwide sulfur gasoline level is 150 ppm. The Indian authorities made a list of 50 other cities with the big number of vehicles and high pollution, where it will be required to use the fuel with 50 ppm sulfur, and it is planned to be implemented by 2015.

Several other countries around the world are moving forward with lowering the maximum fuel sulfur content. This is particularly true in the Middle East, Russia, South Africa and some countries in Latin America. Saudi Arabia expects a nationwide penetration of 10 ppm gasoline by 2013, followed soon after by other countries in the Middle East region, while Russia plans to switch to 10 ppm gasoline by 2016. South Africa has agreed to enforce 10 ppm gasoline by 2017 (OPEC, 2011). Projected gasoline qualities in respect to sulfur content for 2012–2035 are shown in Table 3 (OPEC, 2011).

Table 3 *Expected regional gasoline sulfur content (OPEC, 2012)*

Region	2012	2015	2020	2025	2030	2035
US & Canada	30	30	10	10	10	10
Latin America	520	255	130	45	30	20
Europe	13	10	10	10	10	10
Middle East	605	235	75	25	16	10
FSU	315	115	35	20	12	10
Africa	795	493	245	165	95	65
Asia-Pacific	205	130	65	35	20	15

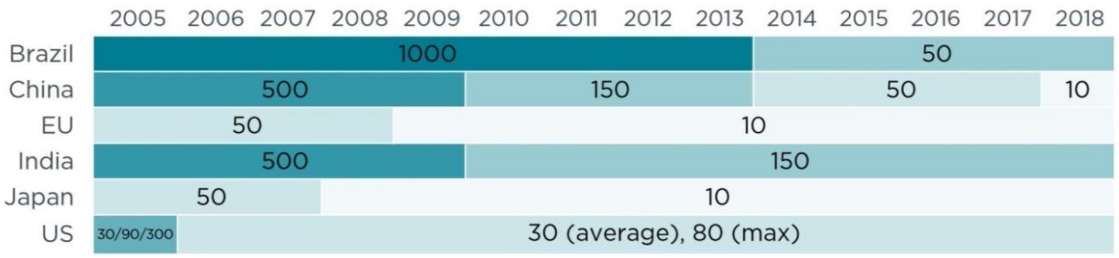

Figure 9 *Selected gasoline sulfur levels (ppm) in countries and regions around the world. Nationwide standards are shown; Brazil, China, and India have stricter fuel quality in some sub-national and municipal areas (ICCT, 2013)*

(ii) *Diesel quality specifications*

European Fuel Quality Directive has required the on-road and off-road diesel fuel sulfur content to be set at 10 ppm since 2011. Same maximum level of 10 ppm was legislated in Japan, Hong Kong, Australia, New Zealand, South Korea and Taiwan. A switch to 15 ppm for on- and off-road diesel was fully aligned in Canada since 2010. The same nationwide average level of 15 ppm came into effect in US in 2012, with the exceptions for small refineries, which are required to do so by 2014.

China planned to reduce its on-road diesel sulfur to 350 ppm in July 2012. This limit, however, is still not widely enforced. However, at the more regional level, Beijing has a diesel sulfur limit of 10 ppm, while cities of Shanghai, Guangzhou, Shenzhen, Dongguan and Nanjing have required a 50 ppm maximum since May 2012. India has also set two different diesel fuel specifications, one for nationwide supply and the other for 20 selected cities. The sulfur content specification for 20 urban centers is established at a 50 ppm maximum, and the national specification is 350 ppm. Other countries in Asia where improvements in on-road diesel quality have been observed include Indonesia, Malaysia, Philippines and Thailand.

In Latin America, the maximum sulfur limit for premium diesel in Argentina was set to 10 ppm in June 2011. Chile has required 50 ppm diesel since 2006. In other countries, such as Brazil, Ecuador and Mexico the progress has been reported, however the majority of Latin America has sulfur limits for diesel oil above 500 ppm.

Totally different situation do exist in Africa. The average sulfur content is in the range of 2,000 to 3,000 ppm for on-road diesel, and much higher for off-road. The only exception is South Africa, which plans a switch to 10 ppm fuels by 2017.

***Table 4** Expected regional on-road diesel sulfur content (OPEC, 2012)*

Region	2012	2015	2020	2025	2030	2035
US & Canada	15	15	15	10	10	10
Latin America	1,085	440	185	40	35	20
Europe	13	10	10	10	10	10
Middle East	1,725	415	155	70	20	10
FSU	440	175	60	15	10	10
Africa	3,810	2,035	930	420	175	95
Asia-Pacific	400	200	100	45	25	15

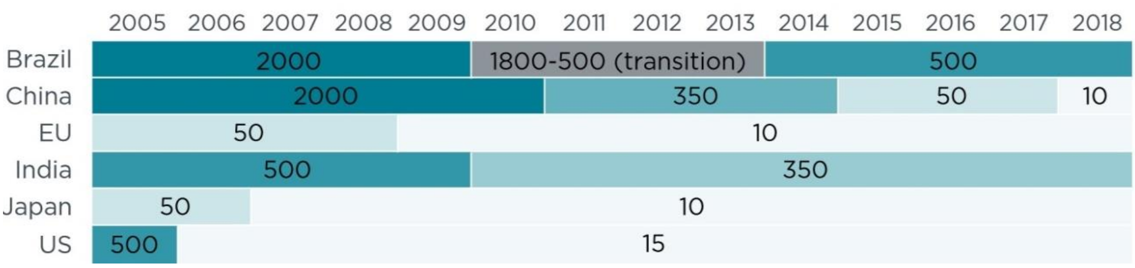

***Figure 10** Selected diesel fuel sulfur levels (ppm) in countries and regions around the world. Nationwide standards are shown; Brazil, China, and India have stricter fuel quality in some sub-national and municipal areas (ICCT, 2013)*

Table 4 summarizes regional diesel fuel qualities between 2012 and 2035 for on-road diesel, with a projected step-wise progress in quality improvements for all developing regions.

The authorities in Europe and North America already require ultra low sulfur level for on- and off-road fuel. The value is 15 ppm in North America and 10 ppm in Europe. By 2020, the most considerable reduction in sulfur content for on-road diesel compared to 2012 is projected to be in Latin America, the Middle East, and in FSU countries. With the exception of Africa, all regions are projected to reach an average on-road sulfur content of below 20 ppm by 2035 (OPEC, 2011).

(iii) Other products

In terms of other products, such as heating oil, jet kerosene and fuel oil, these are increasingly becoming targets for tighter requirements, especially in developed countries.

Sulfur content in Europe's distillate-based heating oil was reduced from 2,000 ppm to 1,000 ppm in January 2008, and some countries, for example, Germany, provide tax incentives for 50 ppm heating oil to enable the use of cleaner and more efficient fuel burners. Parts of North America plan to reduce sulfur levels in heating oil to 15 ppm before 2020. Elsewhere, some progress is expected to be made in reducing the levels of sulfur in heating oil, but not to very low levels, and only after the transition in transportation fuels is completed (OPEC, 2011).

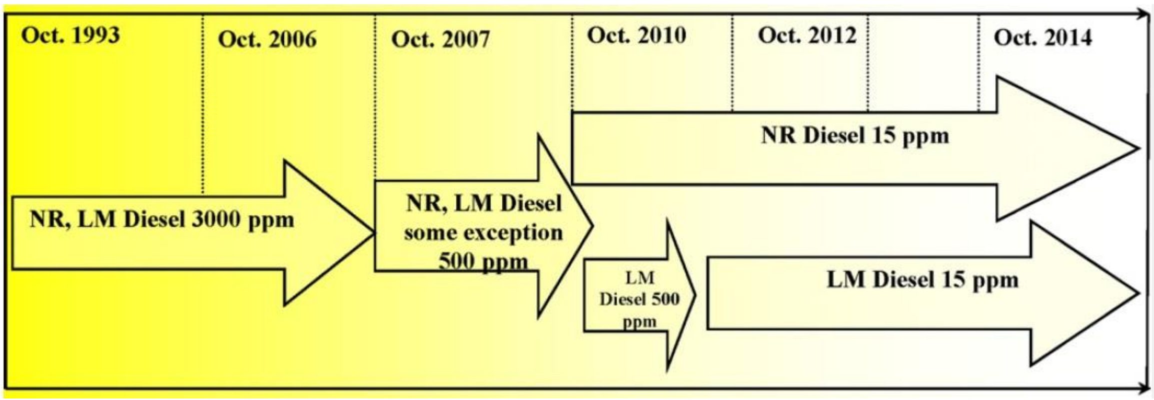

Figure 11 *Trends in sulfur specification for non-road diesel (NR, non-road and LM, locomotive and marine diesel) (Stanislaus et al., 2010)*

In Europe, reductions in the sulfur content of jet fuel have been discussed with initiatives aimed at global harmonization. However, no major progress has been achieved until now and, current jet fuel specifications still allow for sulfur content as high as 3,000 ppm, although market products run well below this limit, at approximately 1,000 ppm. Longer term, it is expected that jet fuel standards for sulfur content will be tightened to 350 ppm in industrialized regions by 2020, followed by other regions in 2025. Industrialized regions are also assumed to see a further reduction to 50 ppm by 2025 (OPEC, 2011).

Marine bunker fuels are also subject to regulation. As of January 2012, the global sulfur cap was lowered from 4.5% wt to 3.5% wt, and will be further lowered to 0.5% wt (5,000 ppm) as of January 2020. In September 2012, the European Parliament approved final legislation requiring all ships in the EU waters to switch to 0.5% wt sulfur fuel, or use corresponding technology allowing ships to reach the required emissions reduction, in 2020 (OPEC, 2011).

5. Challenges in production and processing

The studies on crude quality issues and up-to-date statistical data demonstrate all over again the relevance of the topic addressed. The quality of feedstock and crude slate is considerably deteriorating, becoming heavier and sourer (Figure 7-8). Commonly, the production and processing of high sulfur crudes and sour gases meet five major challenges, which have an effect on the development of energy efficient, low-cost technologies for separation units and to generally production schemes (Lepoutre, 2008).

Technical challenges

Crude oil and natural gas with high content of sulfur compounds claim complex and capital-intensive processes at all stages of production and handling, from upstream, through midstream to downstream segments of petroleum industry.

Technical challenges of development of high sulfur reservoirs are not defined directly. It differs from case to case. Nevertheless, there is a common challenge for almost all sour crude oil projects. This challenge is corrosion related problems. The corrosive environment is typically created when there is high content of H_2S and CO_2 combined with high pressure and high temperature. In such corrosive environment just a few materials can withstand. Moreover, because of high toxicity of the H_2S and the danger of metal failure as a result of stress corrosion cracking, extreme caution must be taken in selecting materials to drill and produce this type of energy source securely (Hamby, 1981). Causes of corrosion, corrosion control and mitigation tools will be described thoroughly in the following chapters.

Economic challenges

The next challenge is economic. It is linked to the high technical costs related to the production of sour crudes containing large amounts of acid gases. The size and the cost of process units and of acid gas handling facilities, such as H_2S transformation into sulfur units, shipping/storage of sulfur, compression, pumping or re-injection facilities, strongly dependent on the amount of feed stock.

Environmental challenges

The following challenge is environmental. Nowadays, the governments and environmental protection agencies have put limits on sulfur compounds in refined fuels. The tendency shows that one decade later the requirements will be much more stringent putting under the pressure oil and gas companies to develop more environmentally friendly technologies. To achieve this task significant amount of money has to be spent on research studies and process facilities.

Safety challenges

Production of sour oil and gas reserves with high content of hydrogen sulfide, leads to handle large quantities of this harmful gases. Hydrogen sulfide can be found in different states, the dense phase of it is precipitated in the acid gas facilities, and acid gas removal unit. Therefore, production and processing facilities is designed by taking account of sour gases, and it is particularly constrained by safety, because H_2S is highly toxic.

Sulfur marketing and environmental challenges

The last challenge is related to the sales of produced sulfur and its storage without harmful effect on the environment. Due to decreasing world demand for elemental sulfur, the economics of recovering sulfur from sour crude and natural gas has become unfavorable. The sulfur market is globally saturated. Even though, some companies are trying to find a solution for different utilization of sulfur, such as sulfur concrete, for instance.

5.1 Corrosion

Production, transportation and processing of crude oil and its following use as refined products and feedstock for chemicals claim a complex process. All of these processes are accompanied by various problems and corrosion is a major one, especially for the crude with high sulfur content. To date the annual cost of corrosion worldwide is estimated at over 3% of GDP of the planet, which is literally 3.3$ trillion. For that reason the problems related with corrosion is of extreme importance (Hays, 2013).

It is believed that corrosion should be controlled and mitigated at the early stage of indication. If not it can cause for the additional cost of lost time and involvement of employee, repair of equipment or replacement of whole construction. Without considering corrosion the outcome can be fatal (Nenry & Scott, 1994).

A detailed discussion of corrosion problems has been given by Henry and Scott (1994). Depending on where the corrosion occurs they divided corrosion into several groups, such as Corrosion in the Chemical Industry, Corrosion in Petroleum Production Operations, Corrosion in Petroleum Refining and Petrochemical Operations, and Corrosion of Petrochemical Pipelines. The corrosion caused by sulfur compounds is the following.

5.1.1 Corrosion in petroleum production operations

There are several environmental factors that are more or less relative to oil and gas production operations. The most important one is the environment found in actual reservoir formations. Corrosives encountered in those formations are carbon dioxide, hydrogen sulfide, polysulfides, organic acids, and sulfur in elemental state.

The first corrosion related problem is the presence of sulfate-reducing bacteria (SRB). SRB is in charge of the majority of the bacterial problems in oil production. It sours crude oil and gas leading to corrosion problems, also making it more difficult to refine environmentally friendly, high quality fuels. SRB produces volatile and toxic hydrogen sulfide as a by-product of respiration (Figure 12). The maximum allowable level of H_2S is set as low as 3 ppm, because sulfide concentrations even below 1 mg/l in the water phase may lead to high corrosion rates (Dunsmore, Evans, Jones, Burton, & Lappin-Scott, 2006).

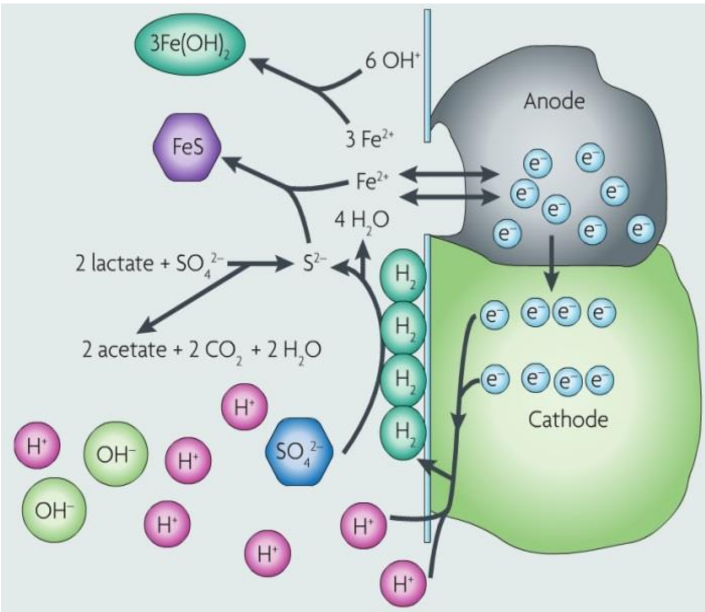

Figure 12 *Sulfate reducing bacteria and corrosion (Muyzer & Stams, 2008)*

Hydrogen sulfide is a relatively strong corrodent. When dissolved in water hydrogen sulfide is extremely corrosive as it becomes a source of hydrogen ions. In the absence of buffering ions, under 1 atmospheric H_2S partial pressure and pH level of 4, water is equilibrated. However, under very high pressure conditions, pH values as low as 3 have been calculated (Nenry & Scott, 1994).

Another corrosive property of H_2S is that it acts as a catalyst to promote absorption by steel of atomic hydrogen formed by the cathodic reduction of hydrogen ions. As a consequence, sulfide-stress cracking (SSC) takes a place. SSC can occur when H_2S is in contact with high-strength steel generally used in drilling, completing, and producing wells. SSC is a type of spontaneous brittle failure which occurs at stresses well below the yield strength of the material. Three conditions must be present for SSC to be present. The first is a surface tensile stress which can be both applied and residual. The second requirement is that the material must be exposed. The third requirement is that embrittling agent, hydrogen sulfide, must be present in the reservoir (Emerson, 2012).

Hydrogen sulfide also enters into a reaction with elemental sulfur. In a gas phase, sulfanes (free acid forms of a polysulfide) under high H_2S partial pressure can be formed so that elemental sulfur becomes mobile and is produced along with gaseous mixtures. Nevertheless, elemental sulfur starts to precipitate as a result of pressure reduction in the upper part of production tubing, which causes sulfur plugging (Nenry & Scott, 1994).

5.1.2 Corrosion in petroleum refining and petrochemical operations

The major corrosion problems in oil and gas processing facilities are not caused by hydrocarbons but by various inorganic compounds, such as water, hydrogen sulfide, hydrofluoric acid, and caustic. There are two essential sources of these conglomerates: feed-stock contaminants and process chemicals, including solvents, neutralizers, and catalysts (Nenry & Scott, 1994).

For practical purposes, corrosion in petroleum refineries and petrochemical plants is classified as low- and high-temperature corrosion. Low-temperature corrosion is considered to take place at temperatures below $260^{\circ}C$ in the presence of water. The main source of low-temperature corrosion is the contaminants in crude oil. Those contaminants are water, hydrogen sulfide, hydrogen chloride, nitrogen compounds and polythionic acids (API, 1973).

Crude oils and gases that contain hydrogen sulfide are processed by most refineries (Hudjins, 1969). Hydrogen sulfide is also can be found in some feed stocks handled by petrochemical plants. This harmful chemical compound forms the black sulfide film seen in almost all refinery equipment (Ewing, 1955). Hydrogen sulfide is the main component of refinery sour waters and can cause corrosion problems in overhead systems of fractionation towers, in hydrocracker and hydrotreater effluent streams, in catalytic cracking units, in sour water stripping units, and, of course, in sulfur recovery units (Piehl, 1968).

Sulfur compounds include hydrogen sulfide, polysulfides, mercaptans, aliphatic sulfides, and thiophenes. Those contaminants, excluding thiophenes, react with metal surfaces at high temperatures forming metal sulfides, organic molecules, and hydrogen sulfide. The corrosiveness of sulfur compounds increases with accumulating temperature. Depending on a specific process, corrosion can be in the form of uniform thinning, localized attack, or erosion-corrosion (Nenry & Scott, 1994).

When it comes to high-temperature processes, corrosion is of considerable importance. Facility failures can have undesirable consequences because refinery processes at high temperatures involve high pressures as well. With crude oil streams, there is always the danger of fire when ruptures take place. That is why corrosion by different sulfur compounds at temperatures between 260 and 540˚C is a general issue in petroleum refining and petrochemical processes (Nenry & Scott, 1994).

5.2 Corrosion control mechanisms in sour systems

There are considerable numbers of corrosion detection methods. Two parameters, such as the operating conditions and chemical nature of the reservoir fluid have to be known in order to select corrosion control method properly. The correct observation and analytical solutions are also important. After necessary studies and considering pros and cons of the available control methods corrosion detection system should be chosen. The major currently available methods are given in Table 5 below, but it should be noted that there are other methods as well, such as iron and manganese counts, galvanic meters, electromagnetic flux leakage, chemical and bacteria analysis, metallurgical examination of failed equipment, simulation studies, and operating condition monitoring.

Table 5 *Corrosion control mechanisms in sour systems (Gerus, 1974)*

Weight loss coupons	*Advantages:*	*Disadvantages:*
Weight loss coupons are metal strips that are located into actual flow stream and allowed to corrode spontaneously. The coupons are scaled before installation. After some time of being in the fluid stream it is cleaned and scaled again before removal. The corrosion rate is defined by weight loss, exposure time, the dimensions of the coupon, and is measured in mm/year or g/cm^2.	•It is cheap and it does not require significant engineering maintenance.	•The relatively infrequent data is obtained; •Coupons placed on the upper part will not detect severe corrosion, as in most gathering facilities the corrosion phenomena is limited to the bottom area of the pipe wall; •Coupons in short term observation periods cannot indicate corrosion rate.
Radiography	*Advantages*	*Disadvantages*
Radiography is the extensively used corrosion control method. The general concept of the method is to place radioactive source on one side of a pipe and to put radiographic film on the other side, and to allow the radioactive emissions to pass through the metal. The X-ray absorption is proportional to the mass of metal that the rays pass through. Hence, the exposed film indicates pits in the pipe as dark spots.	•The actual pictorial representation of the interior of the pipe; •The inspection is held without interrupting of whole process; •The radiography is the only method which detects pitting type corrosion.	•Only specific locations can be observed; •The earth around the pipe is removed at a certain locations.
Ultrasonic inspections	*Advantages*	*Disadvantages*
Ultrasonic inspections are used to measure wall thickness by means of sound waves. The instrument consists of transducer probe which is connected to digital recording tool. The transducer transmits sound waves through the metal and receives the reflected signal.	•The large number of inspections can be made in a relatively short time; •The instrument is portable and can be used any place; •The measurements can be made without stopping the flow line.	•The extreme localization of inspection; •The shape of the corroded surface affects the sound wave reflection.
Visual inspections	*Advantages*	*Disadvantages*
Visual inspections by experienced worker are one of the most efficient methods identifying corrosion problems. While using this method pit depths can be	•Any pit depth can be measured and a pitting corrosion rate can be established; •Excellent for close observation	•Extreme localization of inspection; •Expensive for the installation of valves and bypass loops at

measured and the remaining life of the components of process facilities can be estimated.	of severely corrosive locations.	every location.
Hydrogen probe	*Advantages*	*Disadvantages*
Hydrogen probes detect the level of corrosion affected by hydrogen sulfide. The concept of the method is that atomic hydrogen diffuses through the metal probe and combines in the cavity to form hydrogen gas. The rate of gas formation detected by pressure increases within the sample and this rate is related to corrosion rate in the system.	•Fluid stream is uninterrupted	•Qualitative rather than quantitative indications •The high sensitivity of the instrument

5.3 Corrosion mitigation techniques in sour systems

Mitigation of corrosion is considered to be the final step in corrosion problems in sour systems. First of all, corrosion mechanisms should be defined and then mitigation tool is decided upon. After detection of specific corrosion mechanism, more detailed studies can be carried out, and after that the mitigation techniques can be chosen. There are a lot of mitigation techniques which is used in sour systems and following are the major ones (Gerus, 1974):

(i) Scraping and pigging

The technique of using scraping is based on removal of scale, corrosion products and other compounds from the surface of pipe wall. The scraper is a cylindrical tool with a diameter a little greater than the internal diameter of the pipe and with wire brushes and metal discs (Figure 13). Pigging is performed in the same way as scraping, but the device does not have scraping brushes or plates. The pig is usually placed in gathering line, and then

***Figure 13** Corrosion control by scraping and pigging (O'Meara, 2006)*

propelled through the system, commonly by well pressure. The disadvantage of the method is that pig launching and receiving facilities must be installed through all gathering system.

(ii) Chemical cleaning

Chemical cleaning is the injection of specific chemicals into the system for the purpose of dissolution of deposit or slug. Following removal of the solution results in clean pipe surface. Often, this method is used in combination with pigging after dissolution process is completed. The chemical cleaning is an efficient method; however, as the chemical used can react with the iron in the pipe, precautions should be taken.

(i) Corrosion inhibitors

Corrosion inhibitors injection is the mostly implemented technique to the mitigation sour oil and gas corrosion. Corrosion inhibitors are the compounds that, when introduced to the system, reduces the metal loss due to corrosion attack. These inhibitors can interfere with the anodic or cathodic reaction, moreover, can form protective barrier on the metal surface as it is shown in Figure 14. The dosage and frequency of treatment are dependent on different factors, including severity of corrosion, total amount of fluid produced, percentage of water, nature of corrodent, chemical selected, and fluid level in the casing annulus (Nenry & Scott, 1994).

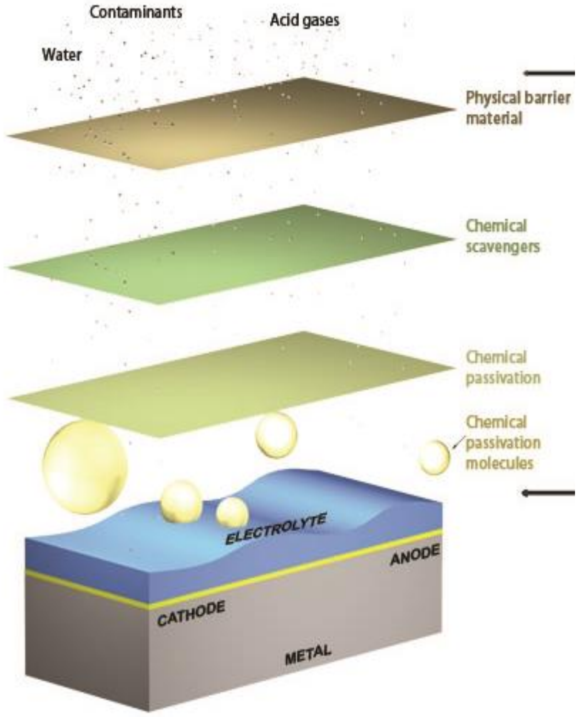

Figure 14 *Corrosion mitigation by inhibitors (ICT, 2013)*

(ii) Dew point control

Corrosion does not occur if there is no complete electrical circuit from anode to cathode. Brine water commonly provides an electrical environment in the produced fluid. So for, if the system with sour content is maintained without water or condensation the occurrence of corrosion becomes insignificant. The system which does not produce water can be protected from water or condensation by controlling the dew point temperature. The dew point temperature can be accomplished by adding thermal energy to the system.

(iii) Biocides

The introduction of biocides into a system is right when the corrosion mechanism has been proved to be biologically induced. They are added into the system to kill the bacteria upon contacts. This results on termination of the corrosive attack on the surface.

(iv) Internal coatings and linings

This method of corrosion mitigation is extremely effective as it helps to isolate the corrosive fluid form the metal surface. The success is achieved by using coatings and linings. The coatings provide a barrier to the diffusion of reactants and the flow of electrical current. As a result, corrosion is avoided. By means coatings can be permanent and temporary. The first one is a thin sheet of corrosion resistant metal or alloy to a thicker base metal at elevated temperatures. Coatings can be formed and fabricated into transportation and process facilities. The second one is applied by the automatic machine that cleans the pipe or by hand sprayers.

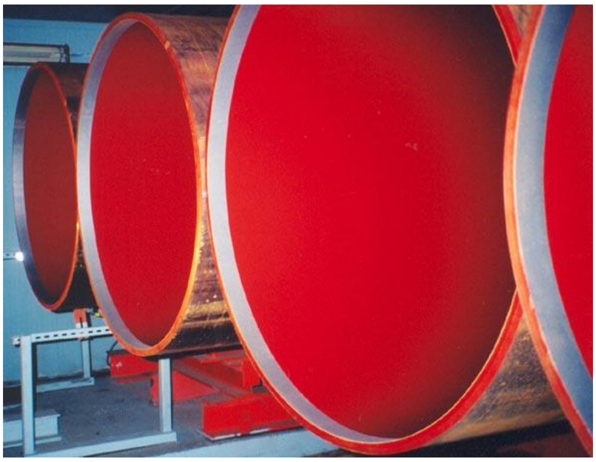

Figure 15 *Typical coated steel pipe (Offshore Technology, 2012)*

6. Petroleum products

6.1 Classification of petroleum products

The assortment of petroleum-refining industry consists of more than 500 types of gaseous, liquid and solid petroleum products in terms of their purpose. Consequently, products are difficult to place on an individual evolutionary scale. However, they can be classified in a wide variety of different ways within the oil industry (Favennec, 2001):

- Refinery operators differentiate between light products (gas and gasolines), middle distillates (kerosene, automotive gas oil and heating gas oil), and heavy products (heavy fuel oil and bitumen).
- For transportation purposes, products are distinguished as white products (motor gasoline, jet fuel, and automotive and heating gas oil) and black products (fuel oil and bitumen).

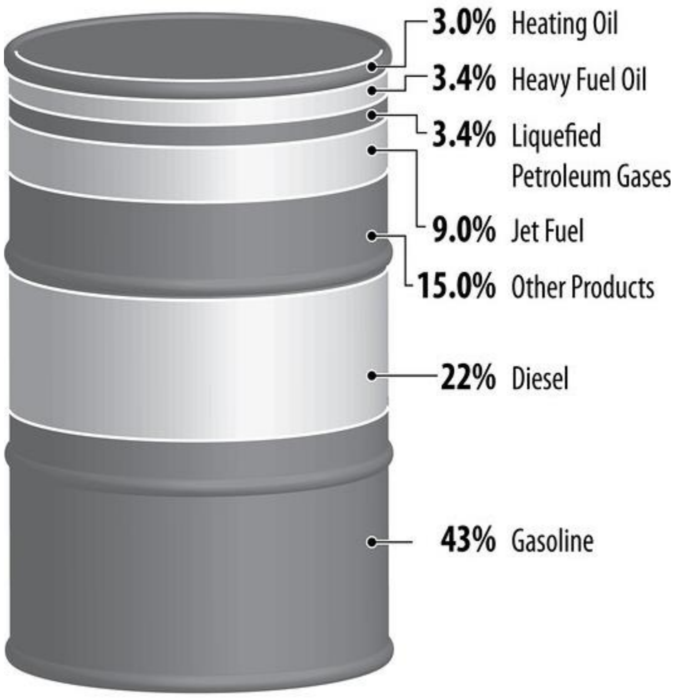

***Figure 16** Typical product produced from a barrel of oil in US (EIA, 2012)*

- Product dealers ascertain between main products and specialties. Main products are sold in a large quantities and distinction is confined so the product assortment is not considerable. Margins for main products, such as motor fuels, jet fuel, heating gas oil and heavy fuel oil, are fairly low. For sales of specialties, such as LPG, aviation gasoline, lubricants and bitumen, there is an opposite situation. They are sold in a little volume but give a high added value, both in terms of the products itself or the service provided.

7. Composition of crude oils and petroleum products

Crude oil is a unique mixture of a great number of individual chemical compounds. Each crude oil has a compound which is not matched exactly in composition or in properties by any other sample of crude oil. Chemical and physical composition of crude oil can vary not only with the location and age of the oil field, but also with the depth of the individual well. More than that, two neighboring wells may produce hydrocarbons with considerably different characteristics.

In order to understand the nature of sulfur compounds in crude oil the basic knowledge of general crude composition is needed. The main constituents present in crude oils are hydrocarbons. The hydrocarbon content may be as high as 97% by weight in light paraffinic oils or as low as 50% by weight in heavy crude and bitumen. Other non-hydrocarbon constituents include small amount of organic compounds containing sulfur, oxygen, and nitrogen, as well as compounds containing metallic elements, such as vanadium, nickel, iron, and copper (Speight, 2007). Sulfur compounds are the focus in this master thesis and will be discussed in more detail throughout subsequent chapters.

7.1 Hydrocarbon compounds

(i) Saturated Aliphatic Hydrocarbons or Alkanes or Paraffins

Alkanes are straight-chain normal alkanes and branched iso-alkanes with the general formula C_nH_{2n+2}. Alkanes are present in all crude oils. Usually, the alkane content in the oils ranges from 20 to 50%. In waxy crudes content of alkanes can be as high as 60% or even more, conversely, in low-paraffinic oils the alkane content may fall to 1.2%. If the distribution of alkanes by fractions is considered, then there is the following general pattern for all crudes: the content of alkanes decreases with increasing boiling point of petroleum fractions (Ryabov, 2009).

(i) Saturated Cyclic Hydrocarbons or Cycloparaffins or Napthenes or Cycloalkanes

Saturated cyclic hydrocarbons make up the bulk of petroleum hydrocarbons. The cycloalkane composition in crude worldwide typically varies from 40 to 70%. The content of these hydrocarbons in some naphthenic oils can sometimes reach 80%. The distribution of cycloalkanes is essentially equal for all petroleum fractions.

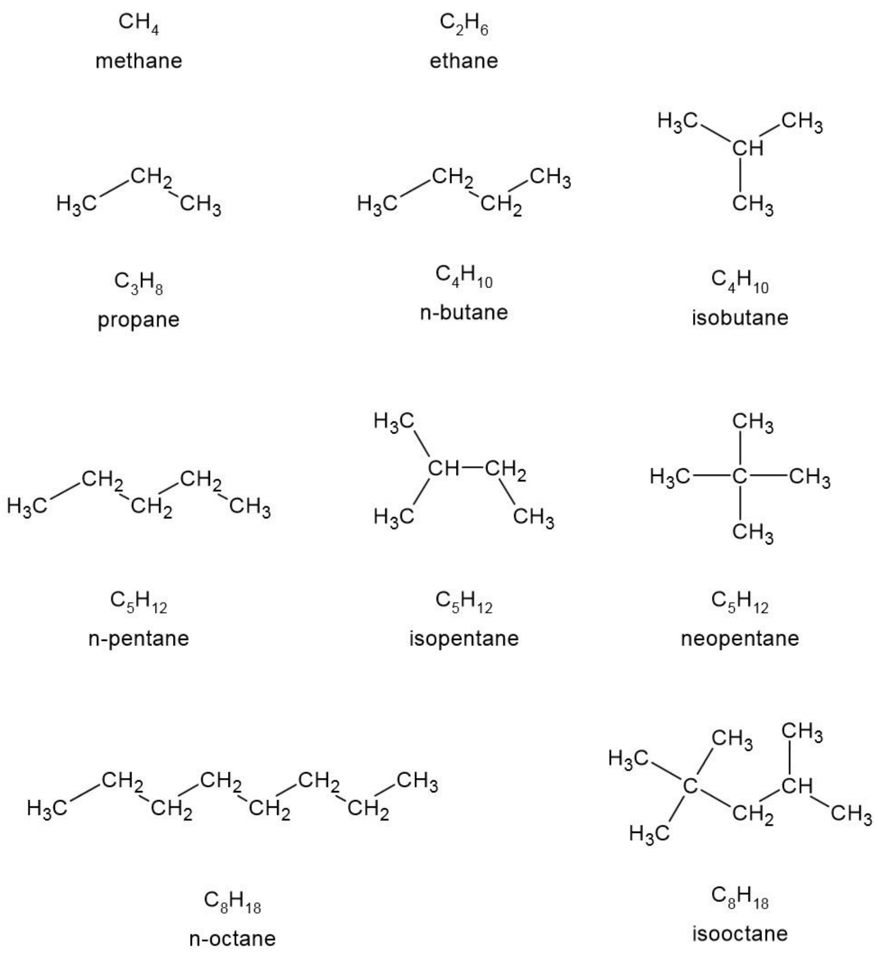

Figure 17 *Isomers of selected paraffins (Robinson, 2013)*

Although the study on chemical composition of napthenes continues for more than 100 years, those hydrocarbons, especially in high petroleum cuts, are the least understood hydrocarbons in crude oils. This is due to the complexity of their composition conditioned by a variety of isomers (Ryabov, 2009).

(ii) Aromatic Hydrocarbons

Aromatic hydrocarbons in crude oil are presented by monocyclic and polyunsaturated hydrocarbons. The content of aromatics normally ranges from 15 to 20%; in aromatic-base crude oil their content can reach as high as 35% (Ryabov, 2009). The presence in their structure of at least one ring containing double bonds significantly influences on their chemical properties. Aromatic hydrocarbons, such as benzene, toluene, and xylenes, are primary raw materials for the petrochemical industry, moreover, they largely contributes to the octane number of gasoline. However, the negative properties of higher homologs, such as environmental and public health problems and degradation of the catalyst activity, are also known (Wauquier, 1995).

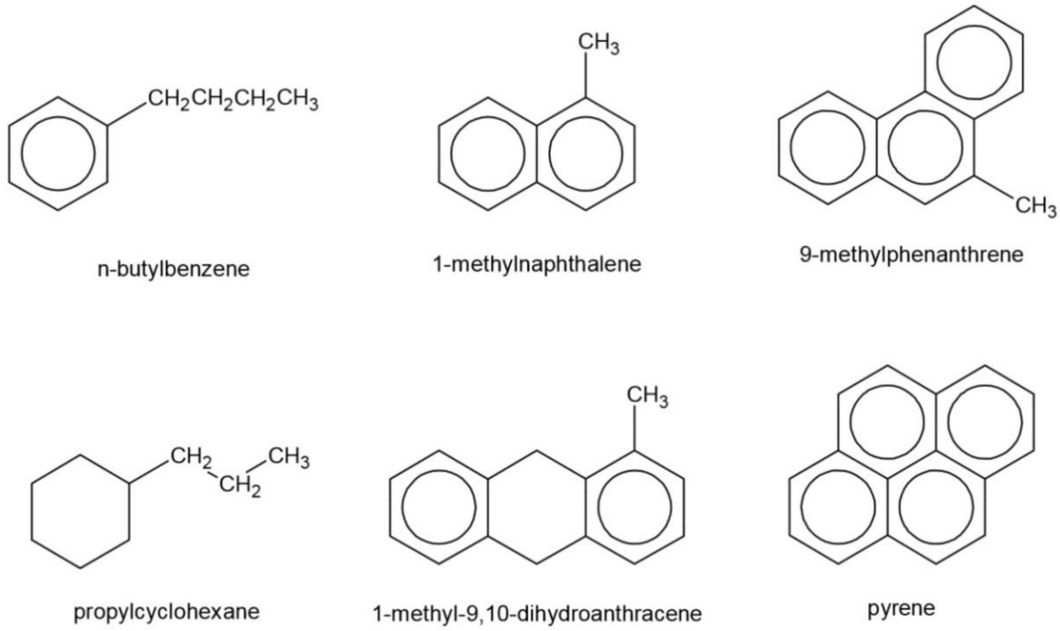

Figure 18 *Aromatics and napthenes found in crude oil (Robinson, 2013)*

(iii) Unsaturated Aliphatic Hydrocarbons or Olefins or Alkenes

The presence of olefins in crude oil has been under dispute for many years. However, evidence for the presence of significant proportions of olefins in Pennsylvanian crudes has been obtained (Speight, 2007). Next evidence is found in East Siberian and Tatar crude oils where the content of olefins can be in range of 15-20% (Ryabov, 2009). Even though, those findings are assumed as a few special cases.

In spite of previous facts, olefins are found in refining products, especially in the fractions coming from conversion of heavy fractions. The first few substances of these chemical compounds are very important feedstock materials for petrochemical industry: ethylene, propylene, and butenes (Wauquier, 1995). Selected light olefins are presented in Figure 19.

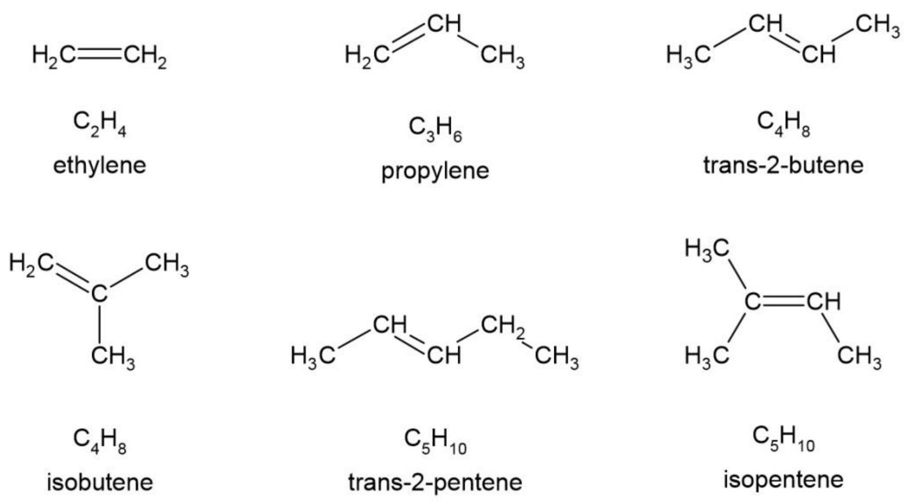

Figure 19 *Selected light olefins (Robinson, 2013)*

7.2 Non–Hydrocarbon compounds

(i) Heteroatomic Organic Compounds

Crude oils contain considerable amounts of organic non-hydrocarbon constituents. Those constituents when present in organic compounds, atoms other than carbon and hydrogen are called hetero-atoms. Sulfur-, nitrogen-, oxygen- containing compounds (Figure 20) appear throughout the entire boiling range, but tend to concentrate mainly in the heavier fractions (Speight, The Refinery of the Future, 2011).

Although they are minor constituents of crude oil, their influence on processing costs can be major. Some of the sulfur and nitrogen compounds that present problems to oil refiners. When burned in vehicles or power plants, high-sulfur fuels cause acid rain. For many refining processes, sulfur is a catalyst poison. Nitrogen is also catalyst poison. Therefore, refiners devote a considerable amount of time and money to remove hetero-atoms from intermediate streams and finished products.

(i) Organometallic compounds

In the heaviest fractions such as resins and asphaltenes organometallic compounds such as nickel and vanadium are found and their concentrations have to be reduced to convert the oil to transportation fuel. The level of metal compounds ranges from few parts per million to 200 ppm for nickel and up to 1200 ppm for vanadium.

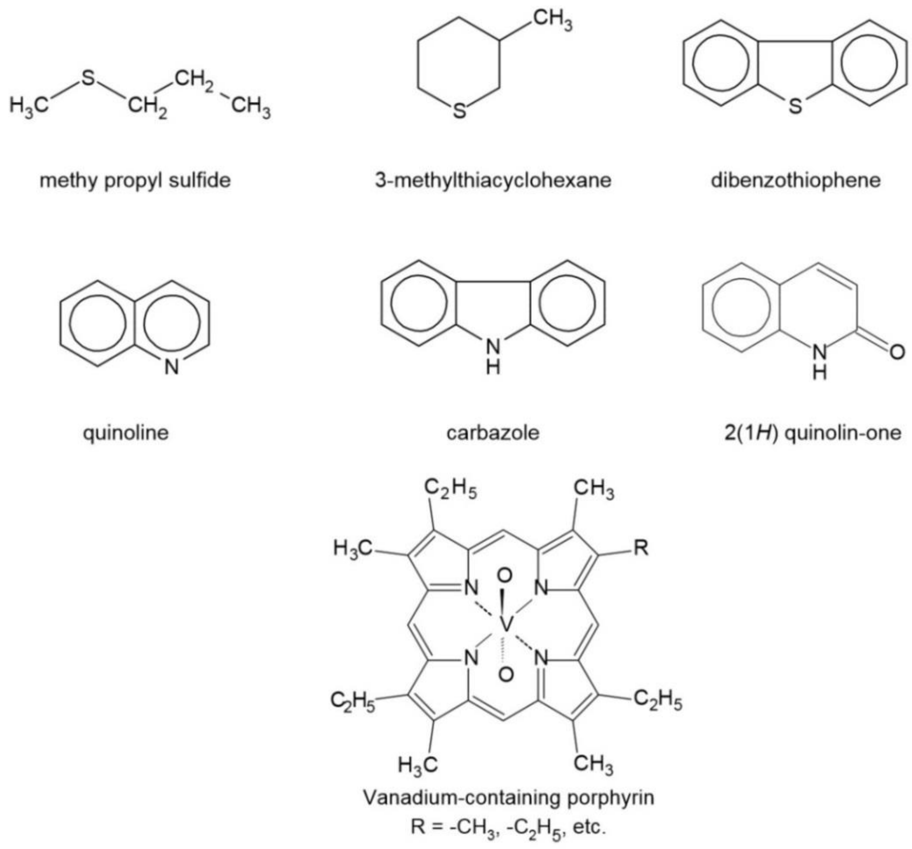

Figure 20 *Hetero-atom compounds found in crude oil (Robinson, 2013)*

8. Sulfur content of crude oils

8.1 Origin of sulfur

Sulfur in crude oil comes generally from the decomposition of organic matter, and with the passage of time and of gradual settling into strata, the sulfur segregates from crude oil in the form of hydrogen sulfide that appears in the associated gas, some portion of sulfur stays with the liquid. Another theory behind origin of sulfur compounds is the reduction of sulfates by hydrogen by bacterial action of the type desulforibrio desulfuricans:

$$4H_2 + SO_4^{=(bacteria)} \rightarrow H_2S + 2OH^- + 2H_2O$$

Hydrogen comes from the reservoir fluid and the sulfate ions are kept in the reservoir rock, as a result hydrogen sulfide is generated. The H_2S formed can react with the sulfates or rock to form sulfur that remains in composition of crude as in the case of oil from Goldsmith, Texas, USA. Moreover, under the conditions of pressure, temperature and period of formation of the reservoir H_2S can react with the hydrocarbons to give sulfur compounds (Wauquier, 1995):

$$3H_2S + SO_4 \rightarrow 4S + 2OH^- + 2H_2O$$

Sulfur compounds are among the most important non-hydrocarbon heteroatomic constituents of petroleum. There are significant amount of sulfur species found in crude oil and sulfur compounds of one type or another are present in all crude oils. Furthermore, only preferred type of sulfur exist in any particular crude oil, and this is dictated by the prevailing conditions during the formation, maturation, and even in situ alteration.

In general, the higher the density of the crude oil, the lower the API gravity of the crude and the higher the sulfur content. The total sulfur in crude oil can vary from 0.04% w/w for light crude oil to about 5% w/w for heavy crude oil and tar sand bitumen. Nevertheless, the sulfur content of crude oils which is produced from different locations varies with time, depending on the chemical composition of newly discovered fields, especially those in different geological environments (Speight, 2007).

8.2 Nature of sulfur compounds

Sulfur compounds are substances of different chemical nature, from the elemental sulfur to hydrogen sulfide and mercaptan compounds, sulfides, open-chain and cyclic disulfides, and heterocyclic derivatives of thiophene, thiophane and other more complex compounds. To date, with the exception of low molecular weight compounds, most of the sulfur compounds oils are not deciphered. Free elemental sulfur is rarely found in crude oils. The emergence of free sulfur is associated with the decomposition of more complex sulfur compounds.

The bulk of sulfur compounds found in crude oil are distributed between the heavy cuts and residues (Table 7) in the form sulfur compounds of the napthenophenanthrene or naphthenoanthracene type, or in the form of benzothiophenes, that is molecules having one or several naphthenic and aromatic rings that usually contain a single sulfur atom (Wauquier, 1995).

Table 6 *Sulfur content of selected crude oils (surface conditions) (Wauquier, 1995)*

Crude oil name	Country of origin	Weight % sulfur
Bu Attifel	Libya	0.10
Arjuna	Indonesia	0.12
Bonny light	Nigeria	0.13
Hassi Messaoud	Algeria	0.14
Ekofisk	North Sea (Norway)	0.18
Arabian light	Saudi Arabia	1.80
Kirkuk	Iraq	1.95
Kuwait	Kuwait	2.50
Cyrus	Iran	3.48
Boscan	Venezuela	5.40

Table 7 *Distribution of total sulfur in the different cuts of crude Arabian light (Wauquier, 1995)*

Cut	Light gasoline	Heavy gasoline	Kerosene	Gas oil	Residue	Crude
Temperature interval, ˚C	20-70	70-180	180-260	260-370	370+	-

Specific gravity, d_4^{15}	0.648	0.741	0.801	0.856	0.957	-
Average molecular weight	75	117	175	255	400	-
Total sulfur, weight %	0.024	0.032	0.202	1.436	3.167	1.80
Number of moles of sulfides/Total number of moles	1/1800	1/855	1/90	1/9	1/2.5	-

The sulfur compounds determined in crude oil are classified into six chemical groups.

(i) Free elemental sulfur S

Free elemental sulfur is rarely found in crude oil; however it can be present in a suspension or dissolved in the liquid. Sulfur, while crude oil is heated, partially reacts with hydrocarbons:

$$2RH + 2S \rightarrow R-S-R + H_2S \qquad (X)$$

It is believed that determination of the presence of elemental sulfur in oil is a complex process and that any declaration of its presence has met with lack of confidence (Eccleston et al., 1992). The crude oil from Goldsmith, which is in Texas, is richest in elemental sulfur (1% by weight for a total sulfur content of 2.17%) (Wauquier, 1995).

(ii) Hydrogen sulfide H_2S

Hydrogen sulfide is a colorless, flammable, harmful gas that smells like rotten eggs (NPI, 2013). H_2S is found in reservoir gas and dissolved in the reservoir liquid (<50 ppm by weight). Often the appearance of H_2S in petroleum fractions is a consequence of thermal decomposition of organosulfur compounds (Ryabov, 2009). It is itself and the sulfur dioxide (SO_2), the product of H_2S combustion cause poisoning of humans, animals and plants.

The presence of H_2S in the reservoir crude determines the number of serious complications for production of oil, due to its high corrosiveness and toxicity. It causes corrosion of steel pipes and tanks, compressors, fittings and other surface equipment, particularly in the presence of carbon dioxide and water vapor in the feed, and under elevated temperatures. Therefore, the gas used as a fuel in industrial furnaces must not contain hydrogen sulfide above the limit determined in each individual case. Furthermore, the presence of H_2S accelerates the formation of gas hydrates.

H_2S is mostly formed during processing operations such as catalytic cracking, hydrodesulphurization, thermal cracking and by thermal decomposition during distillation (Wauquier, 1995).

(iii) Thiols

Thiols or mercaptans are organosulfur compounds that contain a sulfhydryl group (SH), also known as a thiol group, that is composed of a sulfur atom and a hydrogen atom attached to a carbon atom. This molecular structure is what distinguishes thiols from other organic chemical compounds with an oxygen-to-carbon bond configuration. It is also what gives many high velocity thiols a persistent and highly unpleasant odor that is reminiscent of rotten eggs (Mayer, 2013).

The general formula of thiols is R – S – H, where R stands for an aliphatic or cyclic radical. S – H group is responsible for their acidic behavior. The level of thiols in crude oil is very low, if not zero. However, they may appear from other organosulfur compounds during refining operations, which is illustrated in Table 9. It should be noted that the content of mercaptans in crude varies from 0.1 to 15 % mass from total content of sulfur compounds (Ryabov, 2009).

Table 8 *Distribution of mercaptan sulfur among the different cuts of Arabian light crude oil (Wauquier, 1995)*

Nature of cut (temperature interval, ˚C)	Mercaptan sulfur, %	Total sulfur, %	% mercaptan sulfur / total sulfur
Crude petroleum	0,0110	1,8	0,6
Butane	0,0228	0,0228	100
Light gasoline (20-70˚C)	0,0196	0,0240	82
Heavy gasoline (70-150˚C)	0,0162	0,026	62
Naphtha (150-190˚C)	0,0084	0,059	14
Kerosene (190-250˚C)	0,0015	0,17	0,9
Gas oil (250-370˚C)	0,0010	1,40	<0,1
Residue (370^{+}˚C)	0	3,17	0

Table 9 *Mercaptans identified in crude oils (Wauquier, 1995)*

Name	Chemical formula	Boiling point, ℃	Cut
Methanethiol	CH_4S	6	Butane Gasoline
Ethanethiol	C_2H_6S	34	Gasoline
2 methylpropanethiol	$C_4H_{10}S$	85	Gasoline
2 methylheptanethiol	$C_8H_{18}S$	186	Kerosene
Cyclohexanethiol	$C_6H_{12}S$	159	Gasoline

(iv) Sulfides

The sulfides are organosulfur compounds which can have a linear or ring structure. They are chemically neutral. The boiling points of sulfides are higher than of mercaptans for molecules of equal carbon number. Examples of sulfides identified in selected crude oils are shown in Table 10. They create the bulk of sulfur containing hydrocarbons in the middle distillates (kerosene and gas oil), where their content is equal to 50-80% of total sulfur compounds (Ryabov, 2009).

Table 10 *Sulfides identified in the crude oils (Wauquier, 1995)*

Name	Chemical formula	Boiling point, ℃	Cut
3 Thiapentane	$C_4H_{10}S$	92	Gasoline
2 Methyl – 3 thiapentane	$C_5H_{12}S$	108	Gasoline
Thiacyclohexane	$C_5H_{10}S$	141,8	Gasoline
2 Methylthiacyclo-pentane	$C_5H_{10}S$	133	Gasoline
Thiaindane	$C_7H_{12}S$	235,6	Kerosene
Thiabicyclooctane	$C_7H_{12}S$	194,5	Kerosene and gas oil

(v) Disulfides

The disulfides (general formula: R – S – S – R’) are found in small quantities in petroleum fractions with a boiling point up to 300˚C. They account for 7-15% of the total sulfur (Ryabov, 2009).

The disulfides are complex chemical compounds which are difficult to separate; as a result, few have been identified:

Dimethyl disulfide (2,3 dithiobutane)

$$CH_3 - S - S - CH_3$$

Diethyl disulfide (2,3 dithiohexane)

$$CH_3 - CH_3 - S - S - CH_2 - CH_3$$

(vi) Thiophene and derivatives

Thiophene and its derivatives are neutral cyclic and temperature resistant compounds with five-membered ring. They do not dissolve in water, and their chemical properties are similar to aromatic hydrocarbons.

The first determination of thiophene and its derivatives was in 1899, and it was believed that they came from the degradation of sulfides during refining operations. That was until 1953, the year when the methyl-thiophenes were identified in kerosene from Agha Jari crude oil, Iran. The existence of those sulfur compounds was no longer doubted after the identification of benzothiophenes and their derivatives (Table 11).

Table 11 *Thiophene derivatives identified in crude oils (Wauquier, 1995)*

Name	Chemical formula	Boiling point, ℃	Cut
Thiophene	C_4H_4S	84	Gasoline
Dimethylthiophene	C_6H_8S	141.6	Gasoline and Kerosene
Benzothiophene	C_8H_6S	219.9	Kerosene
Dibenzothiophene	$C_{12}H_8S$	300	Gas oil

9. Fundamentals of refinery processing

Petroleum refineries are extensive, continuous flow industrial process plants which involves considerable capital expenditures. The crude oil is processed and refined into more used products such as petroleum naphtha, gasoline, diesel fuel, jet fuel, liquefied petroleum gas, petrochemical feedstocks, home heating oil, fuel oil, asphalt and others. Those transformations occur in a virtue of various physical and chemical processes proceeding in system units by separating feed into different petroleum fractions depending on their boiling range and carbon number distribution, and refining these fractions into finished products, afterwards (MathProInc., 2011). The overview of refining processes and operations are given in Figure 21 and Table 25.

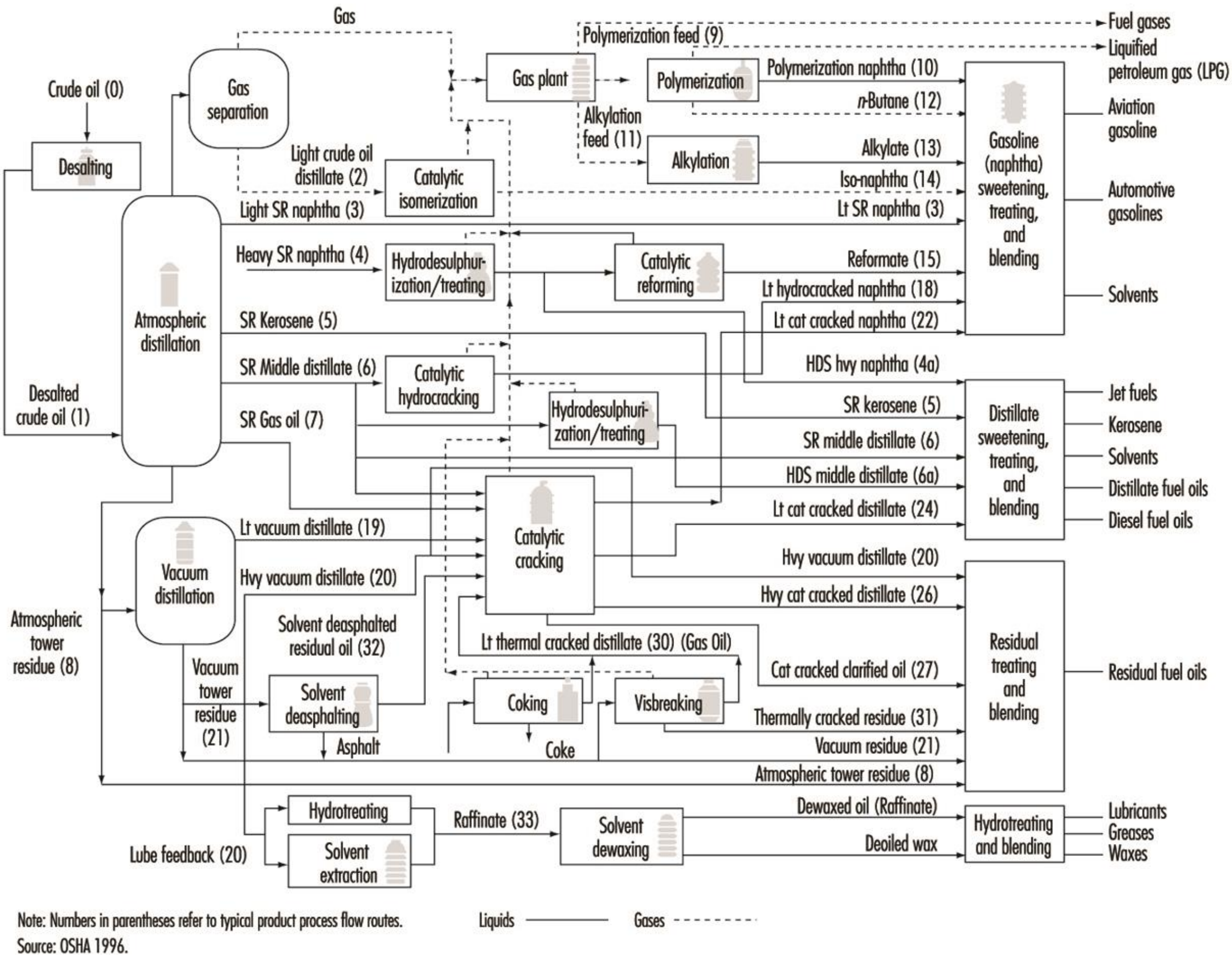

Figure 21 *Overview of refining processes and operations* (Kraus, 2011)

9.1 Classifying refineries by configuration and complexity

All refineries are unique. Their configuration and complexity differ from one refinery to another one. They have different histories, locations, preferred crude oil slate, quality specifications for refined products and market drivers. For that reason, there is no distinct classification which can group all of the possible combinations and permutations of the processes that fit together. Although no two refineries have identical configurations, they can be classified into groups of comparable refineries, defined by refinery complexity (Fahim et al., 2010):

- Simple refinery. It has atmospheric crude distillation, a catalytic reformer to produce high octane gasoline, and middle distillate hydrotreating units.
- Complex refinery. It has in addition to the units of a simple refinery, conversion units such as hydrocrackers and fluid catalytic cracking units.
- Ultra-complex refinery. The refinery has all of the units above in addition to deep conversion units which convert atmospheric or vacuum residue into light products.

The complexity of a refinery can be assessed by calculating the complexity factor. Each unit has a coefficient of complexity (CC_i) defined as the ratio of the capital cost of this unit per ton of feedstock to the capital cost of the crude distillation unit (CDU) per ton of feedstock. The complexity factor (CF_i) of the whole refinery is then calculated from the coefficients of complexity for the units in the refinery as follows:

$$CF = \sum_{i}^{N} \frac{F_i}{F_{CDU}} CC_i$$

where, F_i and F_{CDU} are the feed rate to unit i and CDU, respectively.

10. Classification of desulphurization technologies

There is no unique way of classifying the desulphurization processes. They can be categorized by the type of sulfur compound being removed, the role of hydrogen, or the nature of process used.

Crude oil desulphurization technologies can be grouped based on the nature of a key process to remove sulfur (Figure 22). First type of classification refers to the most studied and commercialized catalytic technologies, which include conventional HDS, HDS by advanced catalysts and/or by advanced reactor design, and HDS with additional chemical processes to meet the fuel specifications.

Second class of desulphurization is based on the physico-chemical processes which vary in nature from catalytic processes, including distillation, alkylation, oxidation, extraction, adsorption or combined version of these processes (Babich & Moulijn, 2003).

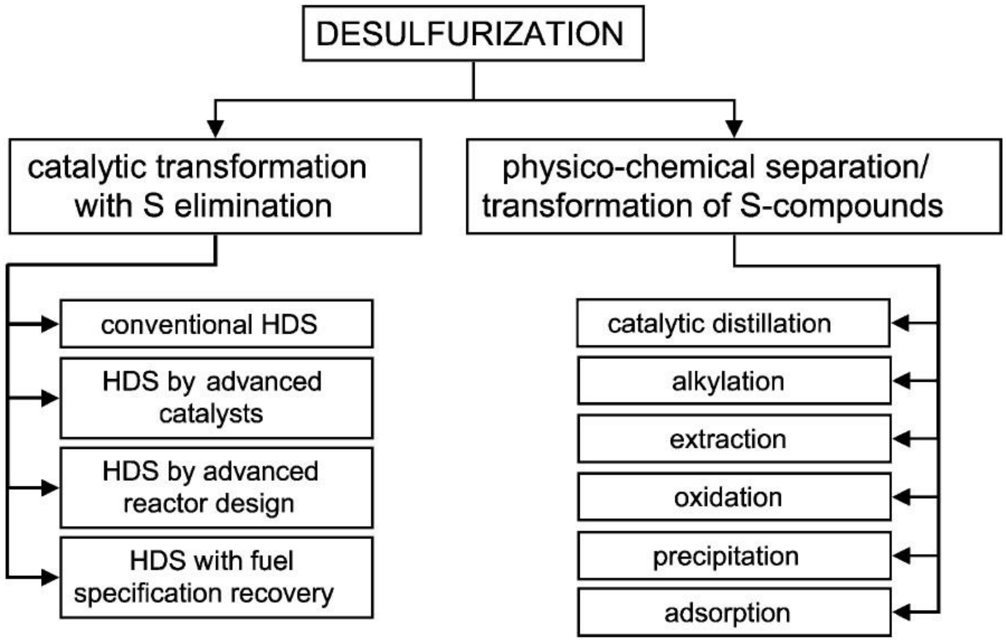

Figure 22 *Desulphurization technologies classified by nature of a key process to remove sulfur (Babich & Moulijn, 2003)*

11. *Hydrotreating*

Hydrotreating is a refining process in which the feedstock is treated at temperature and under pressure where thermal decomposition in the presence of hydrogen is minimized. The main purpose is to remove about 90% of undesirable contaminants including nitrogen, sulfur, oxygen, metals, and unsaturated hydrocarbons (olefins) from liquid petroleum fractions. Hydrotreating processes have been developed in connection with the increase of high sulfur heavy crude refining and more stringent quality requirements for fuels and feedstocks for catalytic processes.

Generally, hydrotreating is applied prior to processes, such as catalytic reforming and catalytic cracking so that the catalyst is not contaminated by unrefined feedstock and that organosulfur compounds are removed and middle-distillate fractions are converted into finished products such as kerosene, diesel and heating fuel oils. Furthermore, hydrogenation processes converts olefins and aromatics into aromatic compounds.

There are several important reasons for removing heteroatoms from petroleum fractions and some of them are listed below (Speight, 2007):

1. Corrosion control and mitigation while refining, handling, or use of different petroleum products
2. Compliance with the environmental regulations and laws regarding detrimental pollutants
3. Production of products with an acceptable odor and specification
4. Increasing the performance and stability of motor gasoline
5. Decreasing smoke formation in kerosene
6. Reduction of heteroatom content in fuel oil to a level that improves burning characteristics and is environmentally acceptable

Hydrogenation processes may be classified as destructive and non-destructive. Destructive hydrogenation is a single-stage or multi-stage catalytic process accompanied by the split of carbon-carbon linkages to produce low molecular weight hydrocarbons from high molecular weight fractions. Hydrogenation treatment requires severe process conditions and the use of high hydrogen pressures in order to minimize polymerization and condensation.

Non-destructive hydrogenation is commonly used for the purpose of improving product quality without considerable conversion of the boiling range. Moderate process conditions are applied so that only the more unstable materials are invaded. As a result, nitrogen, sulfur, and oxygen contaminants are exposed to hydrogenolysis to recover ammonia, hydrogen sulfide, and water, respectively.

11.1 Hydrodesulphurization

Growing dependence on heavy oils and residua has arisen, hence of sustainable decrease of conventional crude oil, due to the depletion of reserves all over the world. As a result, current trend to convert as much as possible feedstock to liquid products is causing an increase in the total sulfur in petroleum products. Hydrodesulphurization (HDS), one type of hydrotreating, is currently playing a major role in product improvement when it comes to sulfur problem, moreover it is the most widely used desulphurization technology.

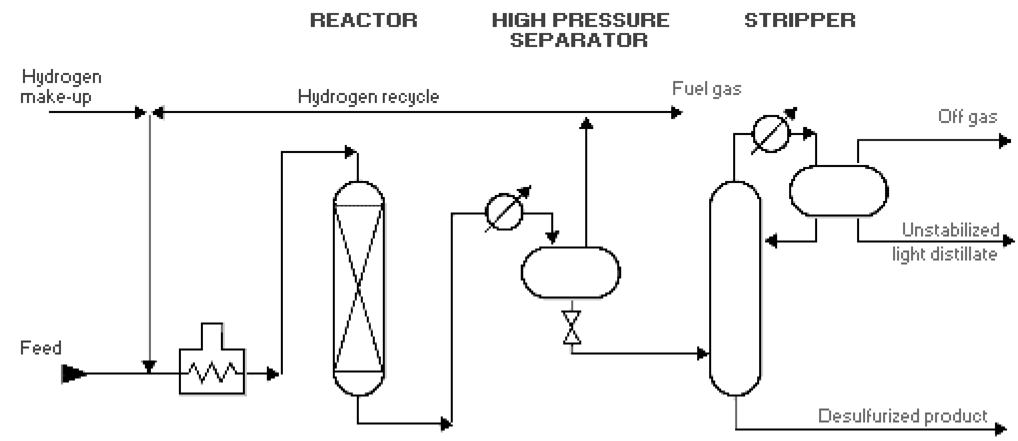

Figure 23 *Schematic of distillate hydrodesulphurization (SET Labs, 2008)*

HDS is a catalytic chemical process commonly used to remove sulfur from natural gas and from refined petroleum products such as gasoline or petrol, jet fuel, kerosene, diesel fuel, and fuel oils. The mechanism is based on reactive adsorption in which metal based adsorbents, such as $CoMo/Al_2O_3$ and $NiMo/Al_2O_3$, capture sulfur to form metal sulfides. The exhausted metal sulfide is sent to regeneration reactor and after reduction with hydrogen is again introduced into the system to remove sulfur from crude. The principal process scheme can be seen in Figure 23, and simplified flow scheme of an oil refinery with possible locations of desulphurization units is shown in Figure 24.

In an industrial hydrodesulphurization unit the hydrodesulphurization reaction takes place in a reactor unit at elevated temperatures ranging from 290 to 445 °C and elevated pressures ranging from 35 to 170 atmospheres of absolute pressure, typically in the presence of a catalyst consisting of an alumina base impregnated with cobalt and molybdenum (usually called a CoMo catalyst) (Speight, 2011). The other important process parameters, such as hydrogen recycle rate, catalyst life, the percentage of sulfur and nitrogen removal for different feedstocks are shown in Table 12.

Table 12 *Process parameters for hydrodesulphurization (Speight, 2011)*

Parameter	Naphtha	Residuum
Temperature (˚C)	300 to 400	340 to 425
Pressure (atm.)	35 to 70	55 to 170
LSHV	4.0 to 10.0	0.2 to 1.0
H_2 recycle rate (scf/bbl)	400 to 1000	3000 to 5000
Catalyst life (years)	3.0 to 10.0	0.5 to 1.0
Sulfur removal (%)	99.9	85.0
Nitrogen removal (%)	99.5	40.0

There are different recently developed technologies. For instance, ConocoPhillips created the first commercial process based on reactive adsorption utilizing nickel on zinc oxide as an adsorbent. This technology is called S-zorb and used for producing ultra-low sulfur fuel. Another research is done by Research Triangle Institute. The development is based on reactive adsorption of sulfur over Fe or Cu promoted alumina-zinc oxide. The main difference of this technology which is called TreND from S-zorb is that it does not require hydrogen nor needs just a little hydrogen (Tuli & Kumar, 2008).

11.2 Process parameters

(i) Hydrogen partial pressure

The high extent of desulphurization can be achieved with the increase of the total pressure in the system. Hence, cocking reactions will be minimized and premature aging of the remaining portion of the catalyst will not be encountered. Hydrotreating processes are carried out at a relatively high pressure of 2 – 5 MPa. Near the upper limit of the set pressure the extent of desulphurization in connection with increasing pressure is negligible.

It was determined that the depth of desulphurization depends on hydrogen partial pressure, because the increase of total system pressure does not substantially contribute to hydrogenation processes. If the hydrogen partial pressure is too low for the selected system, the effectiveness and the service life of catalysts will be decreased. With increasing hydrogen partial pressure up to 3 MPa degree of hydrogenation of sulfur compounds increases very rapidly, and above 30 MPa very slightly (TehnoInfa, 2009).

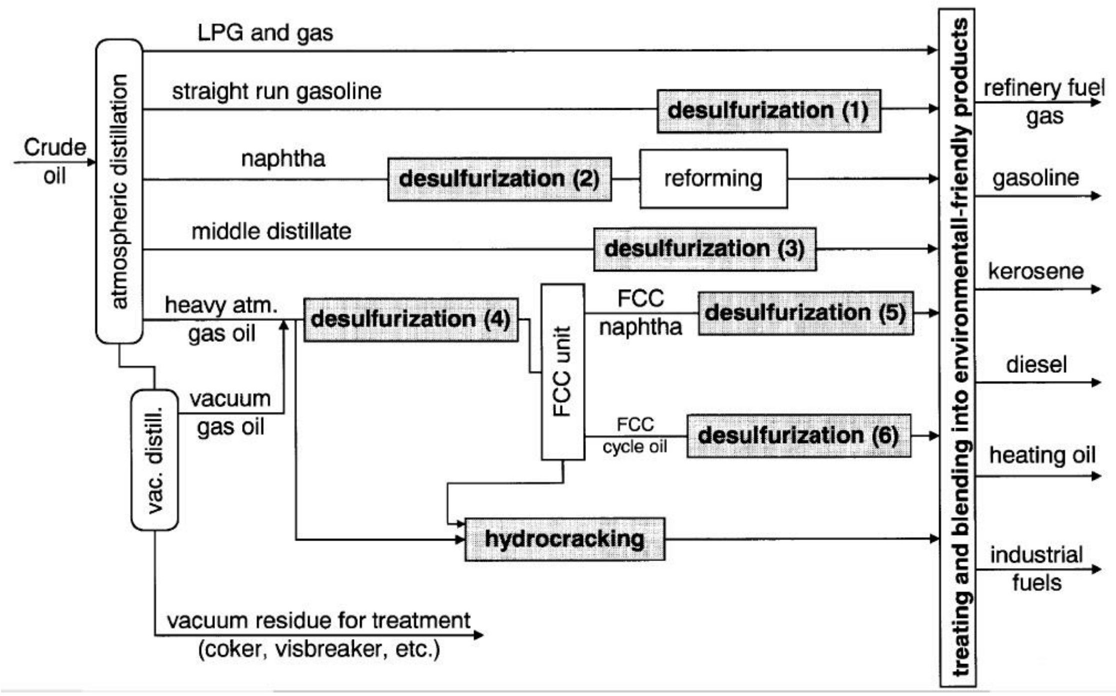

***Figure 24** Simplified flow scheme of an oil refinery with possible locations of desulphurization units (Babich & Moulijn, 2003)*

(ii) Space velocity

As the space velocity is increased, the residence time of feedstock in reactor is decreased, and vice-versa, with the decreasing space velocity the feed contact time with catalyst is increased, hence, the degree of treatment is maximized. However, the low space velocity reduces the amount of feed through the reactor causing reduced plant capacity.

Therefore, there is a maximum allowable space velocity for each feedstock, and a hydrotreatment process is precisely set to this rate.

When selecting the space velocity not only fractional and chemical content of the feed has to be taken into account, but also the state of the catalyst, as well as other process parameters (temperature, pressure) affect the rate of desulphurization (TehnoInfa, 2009).

(iii) Reaction temperature

The optimum reaction temperature depends on the feedstock quality, process conditions and the catalyst activity, and it is in the range of 340 – 400 ˚C. The rate of hydrodesulphurization increases with increasing temperature, reaching a maximum at about 420˚C.

At higher temperatures the rate of hydrogenation is reduced: for sulfur compounds - slightly, and for unsaturated and aromatic hydrocarbons - quite sharply. Consequently, this results in excessive coking reactions and premature catalyst aging rates. For that reason, units are designed to avoid the use of such temperatures (Speight, The Chemistry and Technology of Petroleum, 2007).

(iv) Catalyst life

The loss of catalytic activity is caused by several factors. In normal process conditions, the catalyst deactivation occurs gradually and continuously throughout the cycle due to coke formation, but there are a few points that explain the high rate of deactivation.

Coking occurs due to the presence in the feedstock of high-molecular compounds or by condensation of polynuclear aromatic compounds. In normal operation conditions, a high hydrogen partial pressure and a hydrogenation rate of the catalyst impede the process of coking caused by condensation reactions.

Organometallic compounds decompose and are held on the catalyst surface. Alkali metals can accumulate on the catalyst due to insufficient demineralization of feedstock or because of its contact with the salty water and additives. These metals are unregulated poisons to the catalyst.

Organic nitrogen compounds present in feedstock are converted into ammonia in hydrogenation processes. Since ammonia is a compound with basic properties, it competes with the reactants at the acid sites of the catalyst and inhibits its activity. Most of the ammonia is removed from the reactor unit with water and, therefore, its effect on catalyst deactivation is low.

Over time, the catalyst activity decreases due to the deposition of catalyst poisons and coke on its surface. Reducing the hydrogen partial pressure in the circulating gas and the exaggeration of the process conditions contribute to coking of the catalyst.

Gradually the catalyst "ages" through recrystallization and change of the surface structure and also due to adsorption on the surface of metals and other substances that blocks the active sites. In this case, the catalytic activity significantly decreases and the catalyst is changed to the new one.

12. Unconventional desulphurization technologies

HDS operates in considerably high temperatures and pressures with hydrogen to regenerate organosulfur compounds into lighter hydrocarbons and hydrosulfides. HDS removes light organosulfur compounds, as mercaptans and thiophenes; however, when it comes to heavier sulfur mixtures like dibenzothiophene and its derivatives it is not as effective. HDS is also an expensive process, for instance, the cost of desulphurization of 20,000 barrel of oil per day is as much as $40 million. Moreover, additional hydrogen and sulfur plant capacities would double the investment into refinery plant (Johnson S. W., 1995).

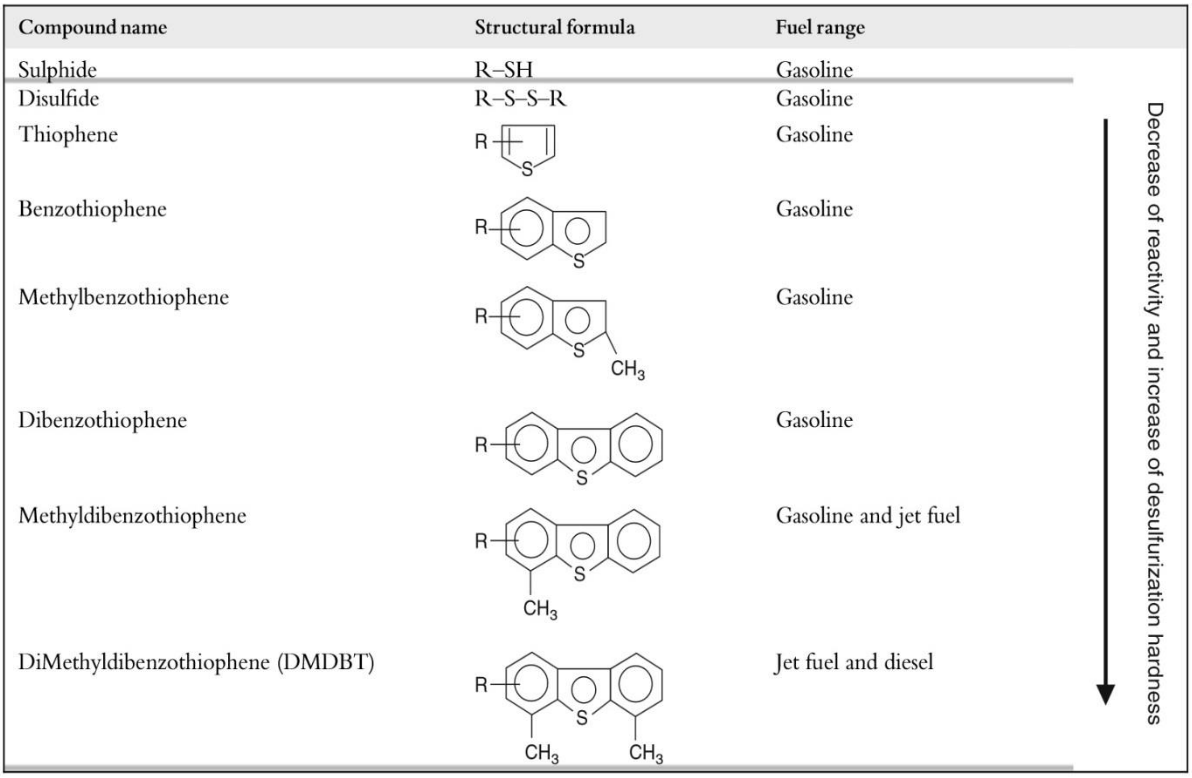

***Figure 25** Reactivity of various organic sulfur compounds in HDS versus their ring sizes and positions of alkyl substitutions on the ring (Fahim et al., 2010)*

12.1 Oxidative desulphurization

Oxidative desulphurization (ODS) is an innovative technology that can be used to reduce the cost of producing ultra-low sulfur diesel (Gatan et al., 2004). It has been in focus since 1960's. Different companies like BP, Texaco, Shell were developing suitable ODS technologies to obtain gas oil fractions with low sulfur content. Nevertheless, with more than 80 patents granted and implied several pilot scales, no commercial plant has yet been built (Tuli & Kumar, 2008).

The basic mechanism of ODS is, first the organosulfur compounds present in middle distillate fractions are oxidized to the corresponding sulfoxides and sulfones by an oxidant (such as H_2O_2, ozone, t-butyl hydroperoxide, t-butyl hypochlorite, etc.) and then these sulfoxides and sulfones are removed from diesel by extraction, adsorption, distillation or decomposition .

ODS has more advantages comparing with hydrodesulphurization. The capital expenditure for ODS is less than for HDS as different fractions can be oxidized under low temperature and pressure conditions and expensive hydrogen is not required. It is relevant for small and medium scale refineries for the locations which are far from water pipelines as the use of hydrogen is avoided (Zongxuan et al., 2011).

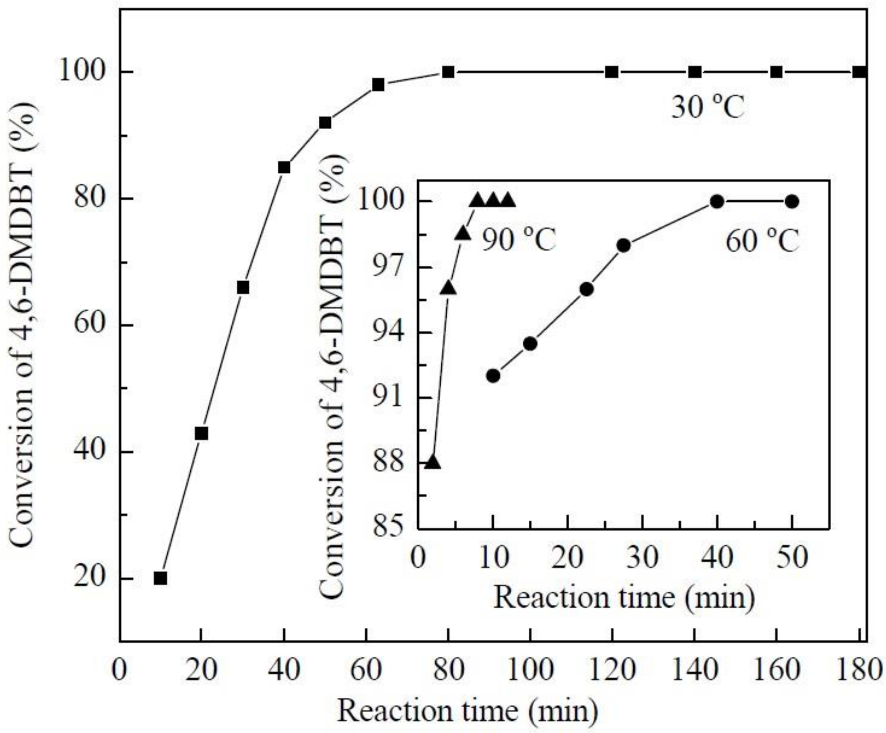

Figure 26 Conversion of 4,6-DMDBT after oxidation with H_2O_2 as a function of reaction time at different reaction temperatures under mild conditions (Zongxuan et al., 2011)

12.2 Biocatalytic desulphurization

The increasing global levels of sulfur content in crude oil have motivated the development of alternate desulphurization technologies. Microbial desulphurization or biodesulphurization (BDS) has gained interest due to the ability of certain biocatalysts to desulfurize compounds (benzothiophene, dibenzothiophene and its derivatives) that are recalcitrant to the currently employed hydrodesulphurization technology.

BDS is a relatively new technological process used to remove sulfur compounds from the crude oil. Special protein-based biocatalysts are needed for BDS. The general idea of BDS is to bring air, whole cell, oil and water into intimate contact, and to produce desulfurized oil stream free of water and biocatalyst cell in a continuously fed, well stirred reactor (Johnson, 1995).

Complex organosulfur compounds, such as dibenzothiophene (DBT) and alkyl DBT, go through different pathway in order to be transformed into more reactive compounds. This pathway is called a sulfur specific desulphurization pathway or simply 4S route. The microorganisms involved in this process are rhodococcus, bacillus, corynobacterium and anthrobacter. The reaction scheme of 4S route is shown in Figure 29 and involves four continuous reaction steps: (i) DBT is oxidized to DBTO (DBT sulfoxides), (ii) DBTO is transformed to DBT sulfones ($DBTO_2$) and (iii) to sulfonate (HPBS), (iv) hydrolytic cleavage to 2-hydroxybiphenyl (2-HBP) and following releases of sulfite or sulfate.

The strong side of BDS is that technology requires less energy and hydrogen. The process is held under ambient temperature and pressure with high selectivity, resulting in decreased energy costs, low emission, and no generation of undesirable side products (Mohebali, 2008).

A conceptual process flow diagram of the BDS process is illustrated in Figure 27. Critical aspects of the process include reactor design, product recovery and oil–water separations. Important new concepts include the use of multiple-staged airlift reactors to overcome poor reaction kinetics at low sulfur concentrations and reduce mixing costs, and the concept of continuous growth and regeneration of the biocatalyst in the reaction system, rather than in separate, external tanks (Monticello, 2000).

12.2.1 Process aspects

Several parameters are substantial in development of BDS process, and the biocatalyst activity is the main one. Other parameters include oil/water ratio, composition of aqueous phase used for biocatalyst suspension during sulfur removal, biocatalyst loading, oil water separation, biocatalyst recycle, recycle of aqueous phase to reduce fresh water usage, and secondary oil separation and purification operations.

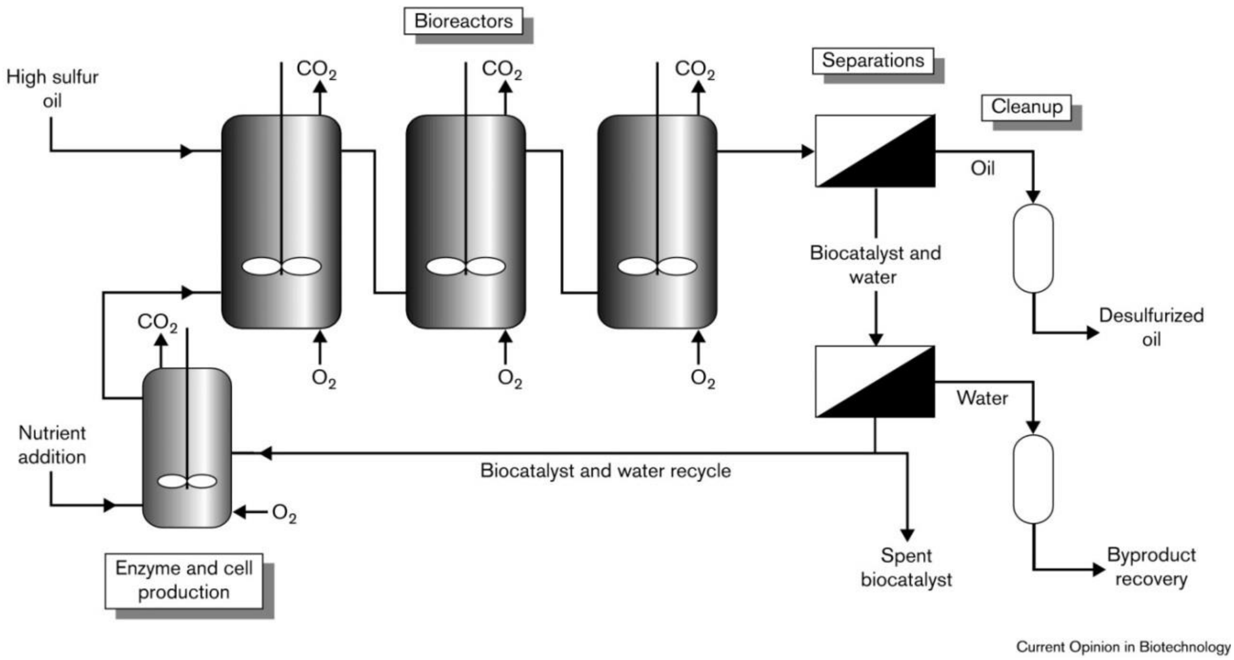

Figure 27 *Conceptual flow diagram for the BDS process (Monticello, 2000)*

A common BDS technology is held in the following steps (Ramirez-Corredores & Borole, 2007):

- Vegetation of the biocatalyst in a fermentative process using appropriate carbon and sulfur sources and other nutrients
- Separation of the biomass from the culture medium
- Use of the biomass as a catalyst for the desulphurization reaction, usually carried out in a completely stirred reactor and in the presence of large quantities of water (at least 1/3 water/oil (W/O) volumetric ratio)
- Separation of the aqueous, oil, and biocatalyst (solid/biomass paste) phases
- Recycling of the biomass paste, to the desulphurization reactor after regeneration /addition of fresh biocatalyst

- Secondary recovery of biocatalyst from the aqueous phase (via filtration, etc.)
- Removal of sulfate via precipitation by lime addition or using other salts
- Removal of the residual water from the desulfurized oil phase (e.g., using high-efficiency separators such as electrostatic separators)

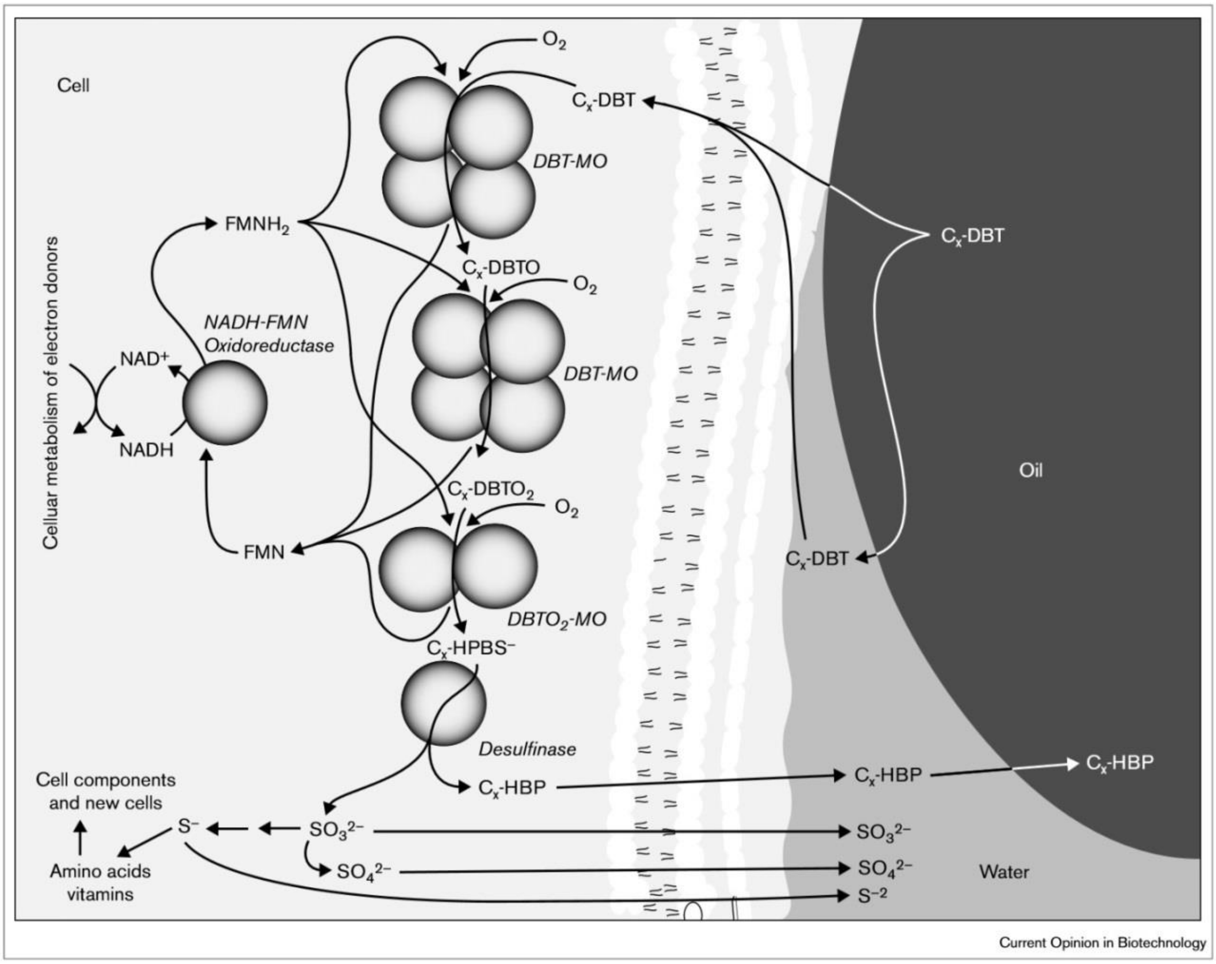

Figure 28 *Conceptual diagram of some of the steps in the desulphurization of oil (Monticello, 2000)*

12.2.2 Barriers for commercialization

Biodesulphurization capital costs are approximately 40-50$ million, which is about half that for hydrodesulphurization. Also operating costs are 15% less. Even though, BDS has certain barriers to use this technology in an industrial scale (Tuli & Kumar, 2008).

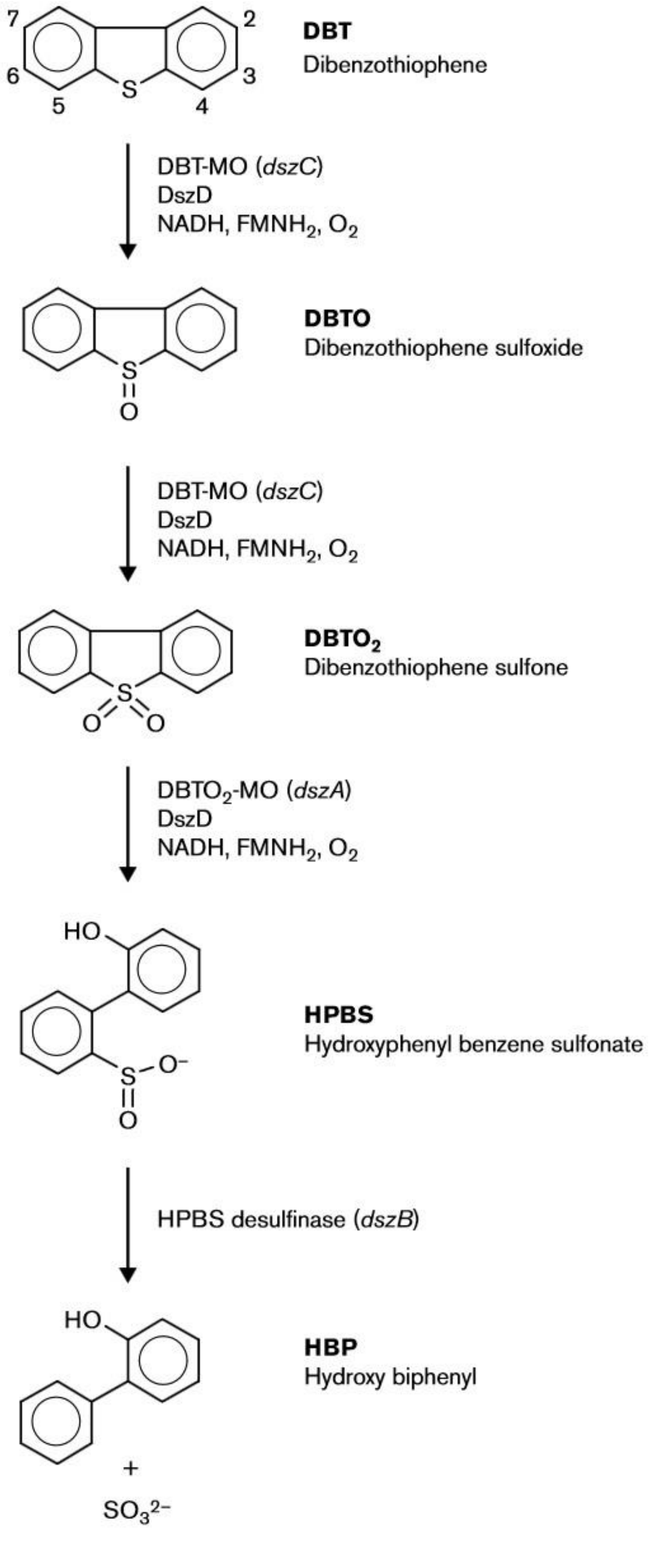

Figure 29 *The "4S" pathway for the biological desulphurization of dibenzothiophene and its derivatives (Monticello, 2000)*

(i) Biocatalyst longevity improvement

First barrier for commercialization of BDS is the biocatalyst longevity. This problem is related to the logistics of sanitary handling, shipment, storage and use of living bacterial strains within the production site and refinery units. The original BDS technology had the acceptable catalyst longevity around 1-2 days. Contemporary design includes production and regeneration units within the BDS process, with the longevity in the range of 200-400 hours (McFarland, 1999). However, highly active and stable biocatalysts adapted to the extreme conditions encountered in petroleum refining have not yet found.

(ii) Poor catalyst selectivity

Poor catalyst selectivity is another problem. Despite the significant progress in improving the technology, organisms that would remove organic sulfur from crude are not selective enough for sulfur compounds and they can remove or destroy the certain amount of hydrocarbons in process. Over the last two decades several research groups have attempted to isolate bacteria capable of efficient desulphurization of oil fractions (Mohebali & Ball, 2008).

(iii) Reactor design

Lack of good reactor design is the next barrier. Several reactor design researches led to advanced process conditions that reduced the influence of mass transport limitations, making the higher volumetric reaction rates possible. Up to date BDS reactors utilize staging, air sparging, and media optimization, hence this reduces the reactor size. However, this also requires downstream processing modifications for emulsion breaking. Moreover, the difficulty of separations increased with increased biocatalyst concentrations due to particle stabilized emulsions (McFarland, 1999).

(iv) Phase contact and separation

Generally bacterial species are responsive to organic solvents. The progress in research of stable and active microorganisms in the presence of non-aqueous solvents is desirable in crude oil fractions upgrading by BDS. In the BDS bioreactor, a limiting factor is the transport rate of the sulfur compounds from the oil phase to the bacterial cell membrane.

Efficiency of sulfur removal is likely to be related to oil droplet size. Therefore, access to organic sulfur by resting cells requires the costly dispersal of the oil fraction in the aqueous phase. The effects of surfactants on bacterial desulphurization of DBT have been investigated in biphasic (oil–water) systems; biodesulphurization has been enhanced by addition of surfactants. It has been suggested that these conditions favored more effective contact between the biocatalyst and the hydrophobic substrate. One problem, which has yet to be resolved, is whether the chemical surfactants would be toxic to the process organisms or act against the characteristic adhesion mechanisms of the bacteria to oil droplet surfaces (Mohebali & Ball, 2008).

(v) Integration to a refinery operations

Integrating a BDS into a refinery is the only way to treat petroleum fractions. Some of the options to integrate BDS units to refinery are given in Figure 30. It is very challenging to make considerable modification of current operations in a refinery. Moreover, BDS processes have to operate at the same speed and reliability as other refinery processes. As a consequence of that employing BDS as a component of refinery operations met with opposition in the petroleum industry (Kilbane & Le Borgne, 2004).

12.3 Novel combined technologies

Convenient desulphurization technologies are not perfect, and considerable work has to be done to improve process parameters and to reduce the energy consumption. Presently available technologies for sulfur removal cannot satisfy the industry requirements and cannot be complied with the market needs. New combined technologies could be one of the solutions to the existing problems.

Nowadays, a lot of novel combined technologies for desulphurization of crude are being reviewed, including the hydrogenation-bacterial catalysis method, the microwave-catalytic hydrogenation method, the three step Biodesulphurization-Oxidative desulphurization-Reactive adsorption (BDS-OD-RA) integrated process, conversion/extraction desulphurization, and the ultrasonic-catalytic oxidation method (Lin et al., 2010).

(i) *Microwave-catalytic hydrogenation process for desulphurization*

Microwave, catalysis and hydrogenation as an integrated process technology could improve the desulphurization rate and this technology is more efficient as opposed to traditional technology. In this integrated technology HDS catalyst can be regenerated with the help of microwave energy. Moreover, microwave inducement could result in higher sulfur removal effect of chemical desulphurization.

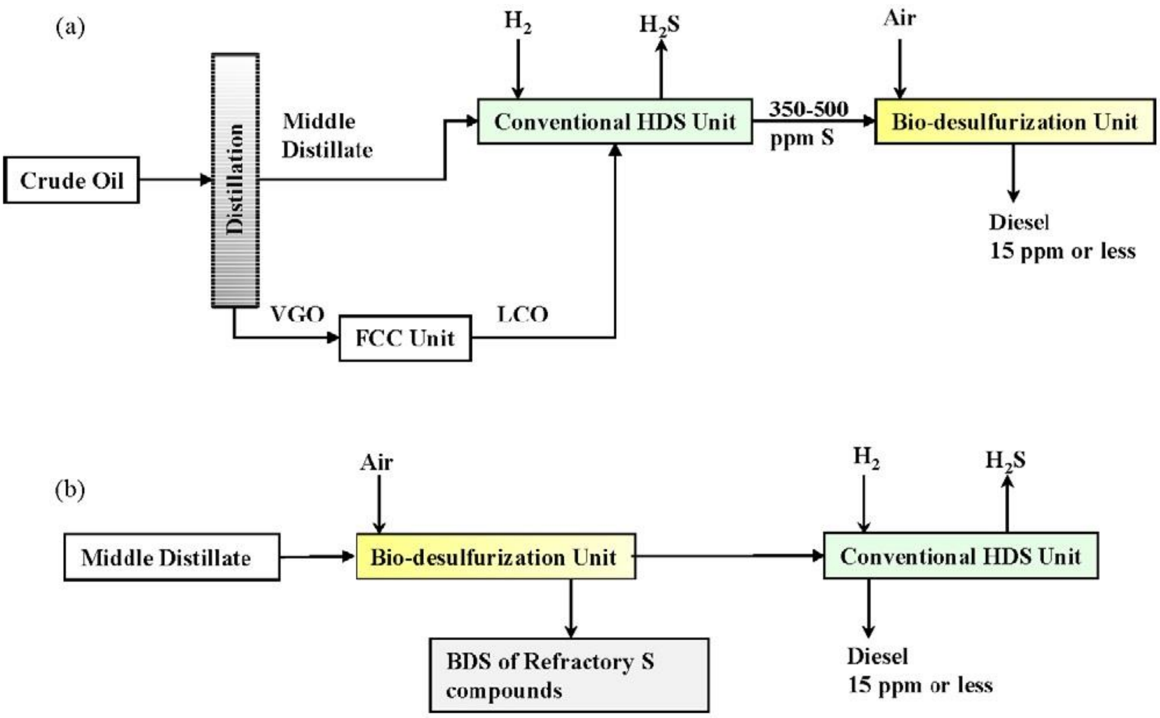

Figure 30 *Options of biodesulphurization in the upgrading of petroleum middle distillates (diesel) to ultra low sulfur levels (a) BDS unit after conventional HDS unit, (b) BDS unit before conventional HDS unit (Stanislaus et al.,2010)*

(ii) *BDS-OD-RA three step integrated process*

Next promising technology is the integrated BDS-OD-RA process. Generally, the process consists of three step treatment. BDS is the first step where the majority of sulfur compounds are removed, and feed is sent to the second-step treatment where it is oxidized, and finally the remaining sulfur compounds are adsorbed. However, there is a different process conditions for high-sulfur and low-sulfur crude oil in BDS step, anaerobic and aerobic conditions are used respectively.

(iii) Conversion/extraction desulphurization

Conversion/extraction desulphurization (CED) technology was originally introduced by Petro Star Inc. in 1996. It is a combined technology which includes conversion and extraction to remove sulfur compounds from middle distillate products.

The feed is mixed with a stoichiometric amount of oxidant (peroxoacetic acid) at temperatures below 100˚C and at atmospheric pressure. After the oxidation process, the fuel is sent to liquid/liquid extraction unit. It has been reviewed that in laboratory-scale experiments diesel fuel with 4200 ppm sulfur was treated to below 10 ppm sulfur (Babich & Moulijn, 2003).

(iv) Ultrasonic-catalytic oxidation method

Sonocracking™ technology was developed by SulphCo and applies ultrasound energy to efficiently oxidize sulfur compounds in a water-fuel emulsion containing a hydrogen peroxide catalyst (Babich & Moulijn, 2003). Several successful large-scale ultrasound tests have been carried out in the EU countries and it has been reported to be economically feasible (Lin et al., 2010).

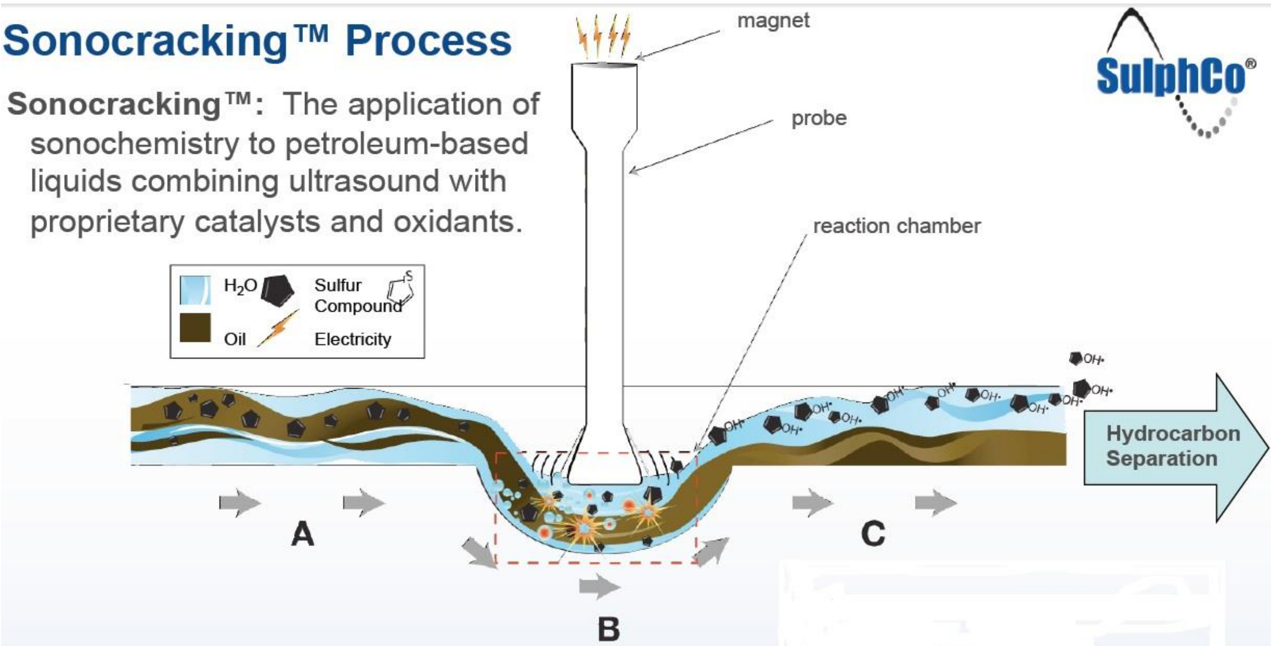

Figure 31 *Effect of ultrasound energy on oxidative desulphurization (SulphCo, 2009)*

The technology operates at 70-80˚C under atmospheric pressure and the residence time for the ultrasound reactor is reported to be only 1 minute (Babich & Moulijn, 2003). Sonocracking^{TM} technology has many advantages, such as simple operation, low cost, low operating conditions, reduced operating cost, and high efficiency.

Graphical illustration of ultrasonic-catalytic oxidation method is given in Figure 31. Feed oil, water, oxidizing agent, and catalyst are mixed in a container and the ultrasonic wave energy is used to convert sulfides into sulfates, sulfoxides, and sulfones, which are then, can be easily removed by separation.

13. Natural gas

13.1 Associated and non-associated gas

Associated gas is a form of natural gas that is associated with the oil in the reservoir. It is also known as associated petroleum gas (APG). The term APG is usually refers to the gas dissolved in the oil; however, theoretically the gas cap is also can be included. When the oil is extracted to the surface, associated gas comes out of solution and usually separated before oil is transmitted via pipeline (PFC Energy, 2007).

Depending on the type of the reservoir, type of lift, how mature is the field, and other factors, volume and chemical content of APG varies from one case to another. When processed and separated from crude oil APG generally exists in combination with other hydrocarbons, such as ethane, propane, butane and pentanes.

Furthermore, raw natural gas contains water vapor, hydrogen sulfide and carbon dioxide, nitrogen and other compounds. Therefore, the natural gas before it is entered into gas pipeline system must be treated. After processing, APG can be utilized in a number of ways, for instance, on-site or regional electricity generation, reinjection for enhanced oil recovery, compression for sale as dry gas, or feedstock for the petrochemical industry (Røland, 2010).

As opposed to associated gas, non-associated gas is in fact never linked to another product. Commonly, industrial projects for the production and refining of this type of gases are absolutely circumscribed by the launch of regional or international markets. In a worst-case scenario, if those export routes are lacking, or because of high transportation expenses, the natural gas reservoirs can remain abandoned for a long time (Rojey et al.,1997).

13.2 Sweet and sour natural gas

Depending on the amount of sulfur compounds present natural gases are classified as sweet dry gas, sour dry gas, sweet wet gas, and sour wet gas. It is presented in Table 13. Figure 32 shows the sour natural gas reserves around the world.

Table 13 *Classification of gases by composition (composition, volume %) (Rojey et al.,1997)*

Category	1	2	3	4
Ethane and higher hydrocarbons	<10	<10	>10	>10
Hydrogen sulfide	<1	>1	<1	>1
Carbon dioxide	<2	>2	<2	>2
Standard designation	Sweet dry gas (non-associated)	Sour dry gas (non-associated)	Sweet wet gas (associated)	Sour wet gas (associated or condensate gas)

13.3 Gas sweetening processes

There is a great number of existing and economically viable gas sweetening processes, and some of them are listed below according to chemical and physical principles used (Arnold & Stewart, 1999):

1. Solid bed absorption:
   - Iron Sponge
   - SulfaTreat® (Licensor: The SulfaTreat Company)
   - Zinc Oxide
   - Molecular Sieves (Licensor: Union Carbide Corporation)
2. Chemical solvents:
   - Monoethanol amine (MEA)
   - Diethanol amine (DEA)
   - Methyldiethanol amine (MDEA)
   - Diglycol amine (DGA)
   - Diisopropanol amine (DIPA)
   - Hot potassium carbonate
   - Proprietary potassium systems
3. Physical solvents:
   - Fluor Flexsorb® (Licensor: Fluor Daniel Corporation)
   - Shell Sulfinol®

- Selexol® (Licensor: Norton Co., Chemical Process Products)
- Rectisol® (Licensor: Lurg, Kohle & Mineraloltechnik GmbH & Linde A.G.)

4. Direct conversion of H_2S to sulfur
   - Claus
   - LOCAT® (Licensor: ARI Technologies)
   - Strertford® (Licensor: Ralph M. Parsons Co.)
   - IFP (Licensor: Institute Francais du Petrole)
   - Sulfa-check® (Licensor: Exxon Chemical Co.)
5. Hydrogen sulfide scavengers
6. Distillation
   - Amine-aldehyde condensates
7. Gas permeation

(i) Solid bed absorption

Solid bed absorption processes are based on the ability of solid particles to remove acid gases through chemical reactions or ionic bonding. The general idea is that the gas stream must flow through a fixed bed of solid particles that separates the acid gases and hold them in the bed. When the solid bed reaches the end of its useful life, the vessel must be removed and replaced (Branan, 2005). Commonly, there are three main processes implemented under this type of sweetening: the iron oxide process, the zinc oxide process, and the molecular sieve process (Arnold & Stewart, 1999).

(i) Chemical solvents

In chemical solvent processes, gas streams containing the acid gases are chemically reacted with a lean solvent in an absorber. The reaction occurs due to the driving force of the partial pressure from the gas to the liquid (Arnold & Stewart, 1999). The solvent absorbs the acid gases and exits the column as a rich solution, which is then sent to a regenerator column where the acid gases are stripped from the solvent (Koch-Glitsch, 2013).

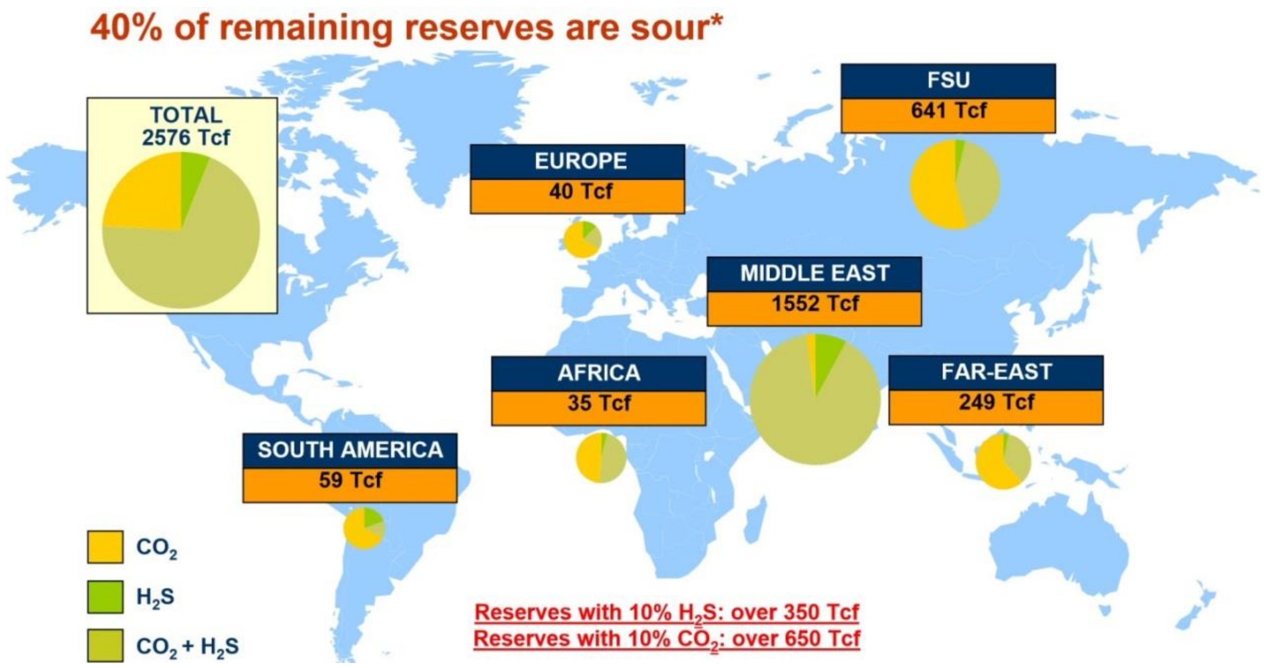

Figure 32 *Sour natural gas reserves around the world (Carrol & Foster, 2008)*

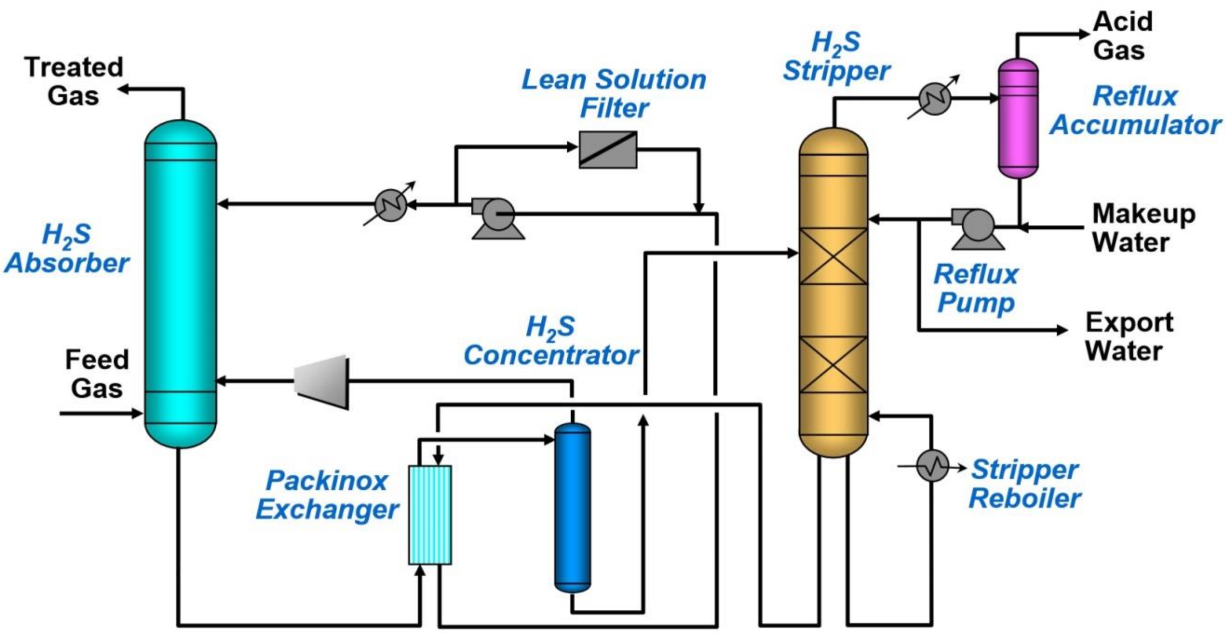

Figure 33 *Selexol® flowscheme for sulfur removal* (UOP, 2009)

(i) Physical solvents

The general idea of physical solvents processes is to use organic solvents to absorb the acid gases. There are no chemical reactions between the acid gas and the solvent, but H_2S and CO_2 is highly soluble within the solvent. Solubility reactions are firstly influenced by partial pressure, and secondarily on temperature. The physical solvent processes are highly effective under higher acid gas partial pressure and lower temperatures (Arnold & Stewart, 1999). There are a number of commercially available technologies within the petroleum industry. The flowscheme of Selexol® process is shown in Figure 33.

Table 14 exhibits the main characteristics of chemical and physical solvents, including advantages and disadvantages of these acid gas removal processes.

Table 14 *Comparison of chemical and physical solvents*

Chemical solvents	
Advantages	**Disadvantages**
Relatively insensitive to H_2S and CO_2 partial pressure	High energy requirements for regeneration of solvent
Can reduce H_2S and CO_2 to ppm levels	Generally not selective between H_2S and CO_2
	Amines are in a water solution, and thus the treated gas leaves saturated with water
Physical solvents	
Advantages	**Disadvantages**
Low energy requirements for regeneration	May be difficult to meet H_2S specifications
Can be selective to H_2S and CO_2	Very sensitive to acid gas partial pressure

(ii) Direct conversion of H_2S to sulfur

Direct conversion technology is based on chemical reactions to oxidize hydrogen sulfide and to produce elemental sulfur. This technology uses the reactions of H_2S and O_2 or H_2S and SO_2. All reactions involve special catalysts and/or solvents and yield water and elemental sulfur. Several commercially available processes, such as Claus® process, LOCAT® process, Stretford® process (Figure 34), and others have been successfully used to remove H_2S from the gas stream.

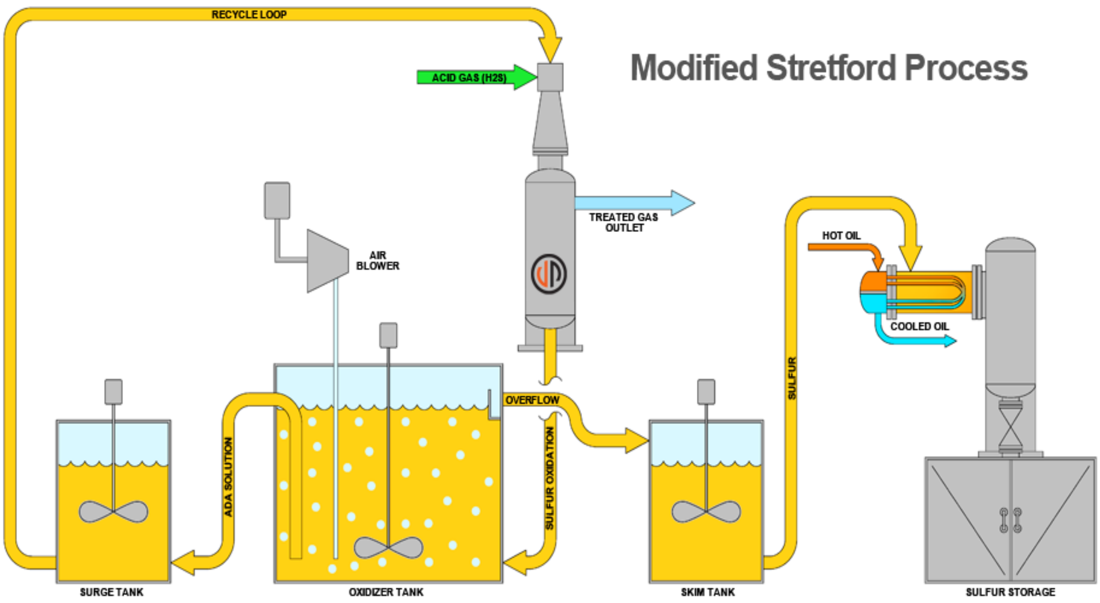

Figure 34 *Modified Stertford® process flow diagram (Joule Processing, 2012)*

It should be noted that direct conversion processes do not release harmful gases like H_2S and CO_2 to the atmosphere, as in the case of previously discussed technologies. The acid gases from chemical and solvent processes can be flared, which would cause of SO_2 release. It is known that allowable level of SO_2 is strictly regulated by environmental authorities, and these limitations are revised periodically (Arnold & Stewart, 1999).

(iii) Hydrogen sulfide scavengers

Sulfide scavengers are based on chemical reactions of commercial additives with one or more sulfide species by converting them into a more inert form. Sulfide scavengers technology is commonly carried out in a continuous sour gas stream. Different scavengers, such as amine-aldehyde condensates, are constantly injected into the system. The most critical parameter is contact time between the scavenger and the sour gas (Arnold & Stewart, 1999).

Effective hydrogen sulfide removal is achieved if there is an irreversible and complete chemical reaction between the scavenger and one or more sulfide species. Upon reaction equilibrium between the three species in solution is achieved, for that reason complete removal of one species serves to remove all three. Insufficient chemical reaction between a species and the scavenger cannot remove all soluble sulfides present (Amosa et al., 2010).

13.4 Process selection factors

Gas sweetening processes were described in the previous chapter. Each of these processes has favored position comparing with others for various cases; hence the following process selection factors should be considered (Kidney & Parrish, 2006):

- The type of acid contaminants present in sour gas stream;
- The concentration of impurities and amount of heavy hydrocarbons and aromatics in the sour gas. For example, COS, CS_2, and mercaptans can affect the design of both gas and liquid treating facilities. Physical solvents tend to dissolve heavier hydrocarbons, and the presence of these heavier compounds in significant quantities tends to favor the selection of a chemical solvent;
- The volume of gas to be treated the temperature and pressure at which the sour gas is available. High partial pressures (3.4 bar or higher) of the acid gases in the feed favor physical solvents, whereas low partial pressures favor the amines;
- The final specifications of the outlet gas;
- The desirability or selectivity required for removing one or more of the contaminants without removing the others;
- The capital, operating, and royalty costs for the process;
- The environmental constraints, including air pollution regulations and disposal of byproducts considered hazardous chemicals.

Moreover, there are different process selection charts (Figures 35-37) which could help to choose the appropriate sweetening processes. In order to do so partial pressure of acid gas in product and in feed has to be known.

14. Refinery of the future

Refinery industry has been developing significantly over the last century. This development is forced by increasing demand for automotive fuels, as well as for gas oils and fuels for domestic central heating, for fuel oil power generation, and for inputs to the petrochemical industries. The following factors have accelerated the development of new processes (Speight, 2011):

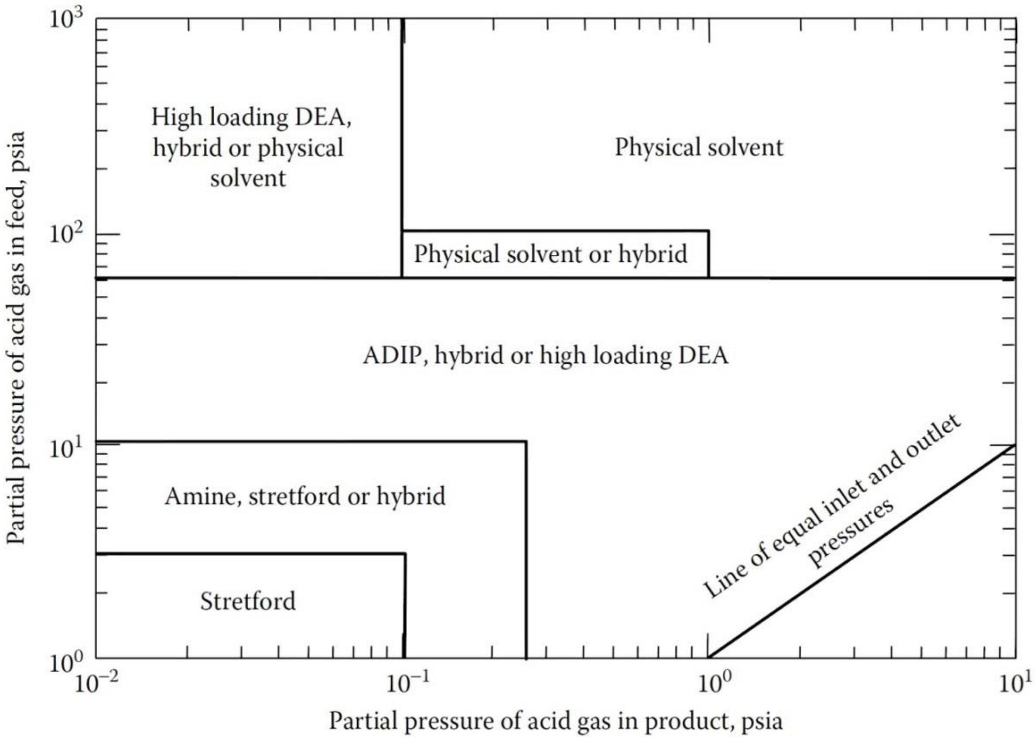

Figure 35 *Process selection chart for H_2S removal with no CO_2 present (Kidney & Parrish, 2006)*

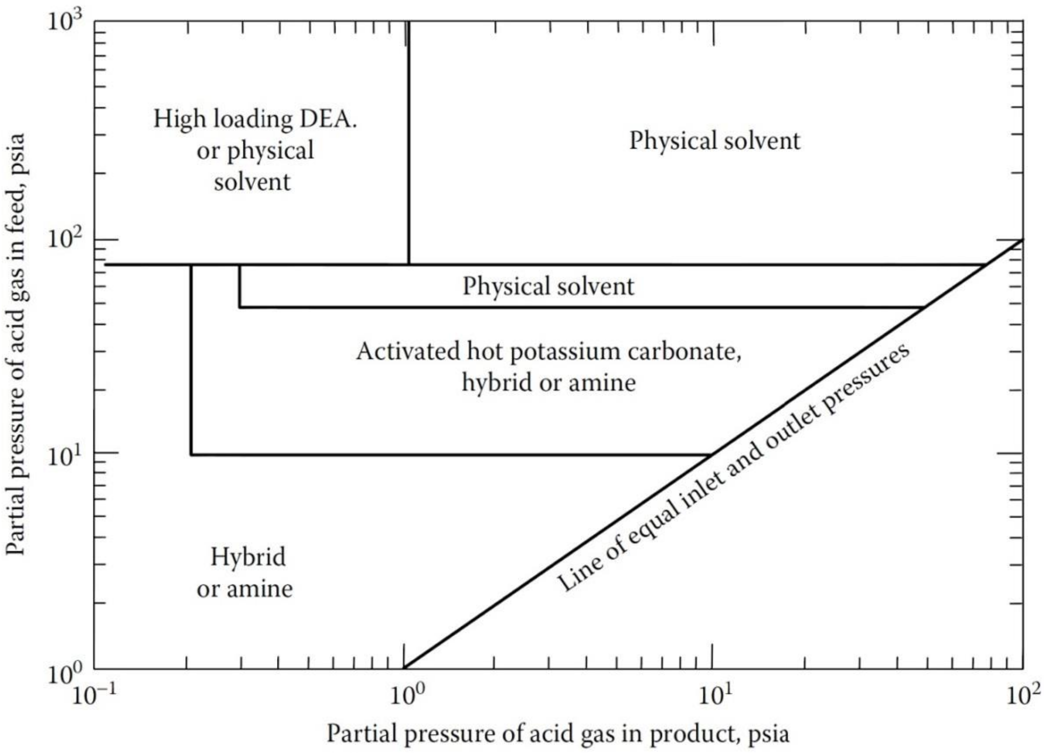

Figure 36 *Process selection chart for simultaneous H_2S and CO_2 removal (Kidney & Parrish, 2006)*

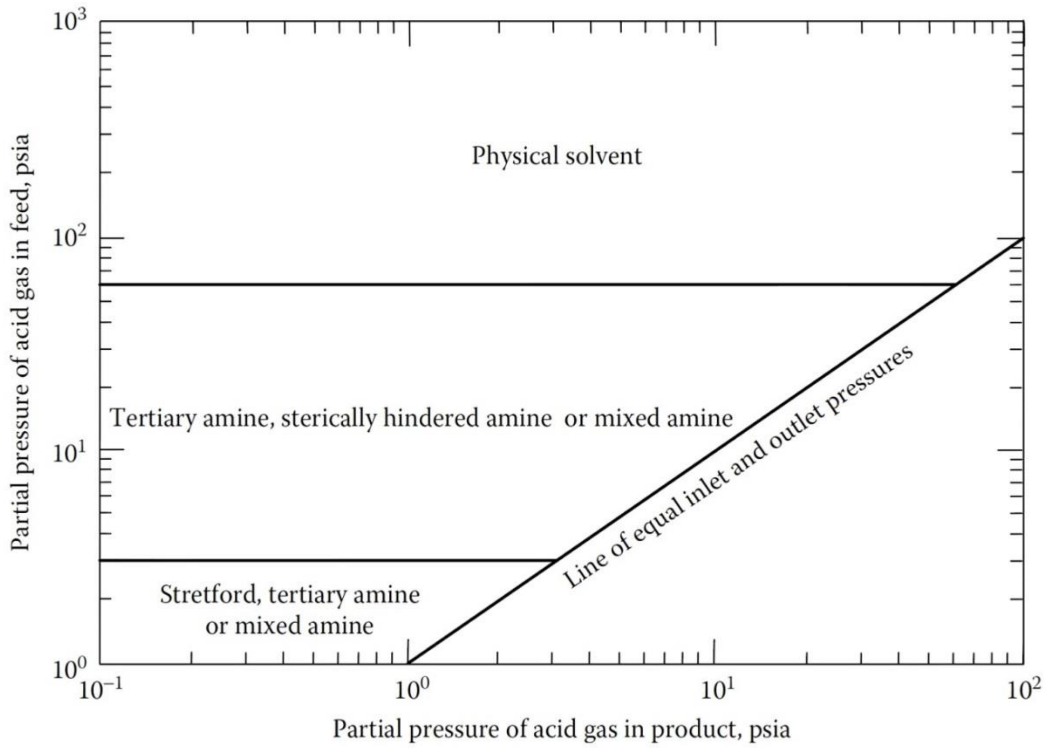

Figure 37 *Process selection chart for selective H_2S removal with CO_2 present (Kidney & Parrish, 2006)*

Table 15 *Natural gas reservoirs with a high H_2S content (Rojey et al., 1997)*

Reservoir	Lithology	Depth (m)	H_2S content (wt %)
Lacq (FRA)	Dolomite and limestone	3100 to 4500	15
Pont d’As-Meillon (FRA)	Dolomite	4300 to 5000	6
Weser-Ems (GER)	Dolomite	3500	10
Asman-Bandar Shipur (IRN)	Limestone	3600 to 4800	26
Urals-Volga (CIS)	Limestone	1500 to 2000	6
Irkutsk (CIS)	Dolomite	2540	42
Alberta (CAN)	Limestone	3506	13
Alberta (CAN)	Limestone	3800	87
South Texas (USA)	Limestone	3354	8
South Texas (USA)	Limestone	5793 to 6098	98
East Texas (USA)	Limestone	3683 to 3757	14
Mississippi (USA)	Limestone	5793 to 6098	78
Wyoming (USA)	Limestone	3049	42

- The high demand for products such as gasoline, diesel, fuel oil, and jet fuel
- Uncertain feedstock supply, caused especially by the changing quality of crude oil, by geopolitical relationships among different nations, and by the emergence of alternate feed supplies such as bitumen from tar sand, natural gas, and coal
- Recent environmental regulations that include more stringent regulations in relation to sulfur in automotive fuels
- Sustainable technological development such as new catalyst and processes

Nowadays, the average quality of crude oil has deteriorated.

To date, according to the statistical information there is a general trend towards reduction of sulfur content of fuels, and this fact will convince that the role of desulphurization increases in importance in the processing operations.

The main developments in desulphurization will follow major paths, such as:

- Advanced hydrotreating (new catalyst, catalytic distillation, processing at mild conditions)
- Reactive adsorption (type of adsorbent implemented, process design)
- Oxidative desulphurization
- Biocatalytic desulphurization
- Combined technologies

Several decades later, the need for hydrogen will be reduced, as new desulphurization technologies and evolution of the older ones are expected to be developed.

In the year 2030 the standard American refinery will be placed at an existing refinery site. That will be mainly due to economic and environmental considerations, as it will be difficult to construct the new refineries at another site. Numerous existing refineries may still be in use, but a lot of processing technologies will be more efficient and more high-tech. Moreover, the main concern for refiners will be the energy efficiency of processing units in order to reduce the cost operating expenses (Speight, 2011).

14.1 Global refinery capacity requirements in the future

Table 16 and Figures 38-40, which are taken from OPEC's annual World Oil Outlook, exhibit information on global crude distillation capacity and desulphurization capacity additions. Improvements in product quality specifications which are previously discussed will influence in considerable desulphurization capacity additions in order to reduce the sulfur level in refined products. It is known that OECD countries are already legislated ultra low sulfur regulations for automotive fuels, further development will be expected in non-OECD countries, because they are also reducing the average sulfur content to low and ultra low levels. It is forecasted that 22 mb/d of additional desulphurization capacity will be required globally by 2035. This number is the largest volume of capacity additions in the period to 2035 (OPEC, 2012).

***Table 16** Global capacity requirements by process (millions of barrels/day) 2011-2035 (OPEC, 2012)*

	Existing projects	Additional requirements		Total additions
	to 2015*	to 2015	2015–2030	to 2035
Crude distillation	**6.0**	**0.7**	**8.2**	**14.9**
Conversion	**4.7**	**1.1**	**5.8**	**11.6**
Coking/Visbreaking	1.5	0.0	0.6	2.1
Catalytic cracking	1.2	0.1	0.5	1.8
Hydro-cracking	2.0	1.0	4.7	7.7
Desulphurization	**6.2**	**3.0**	**12.8**	**22.0**
Vacuum gasoil/Resid	0.2	0.3	1.5	2.1
Distillate	4.5	2.2	8.8	15.5
Gasoline	1.4	0.6	2.4	4.4
Octane units	**1.7**	**1.3**	**2.5**	**5.4**
Catalytic reforming	1.3	1.3	1.4	4.0
Alkylation	0.2	0.0	0.1	0.3
Isomerization	0.2	0.0	1.0	1.1

The most part of desulphurization capacity additions is planned in Asia (10.4 mb/d), the Middle East (3.4 mb/d), Latin America (3.3 mb/d), and the FSU (2.9 mb/d). This is mainly due to expansion of refining base and demand for petroleum products, also tightened nationwide and exported average quality specifications. Figure 40 the data regarding desulphurization capacity additions to the main distillate groups of petroleum products. It can be seen that in the forecasting period from 2011 to 2035, more than 60%

of global desulphurization capacity additions (14 mb/d) are for the desulphurization of middle distillates, whereas 27% for gasoline (6 mb/d), and the rest for vacuum gasoil/residual fuel (2 mb/d).

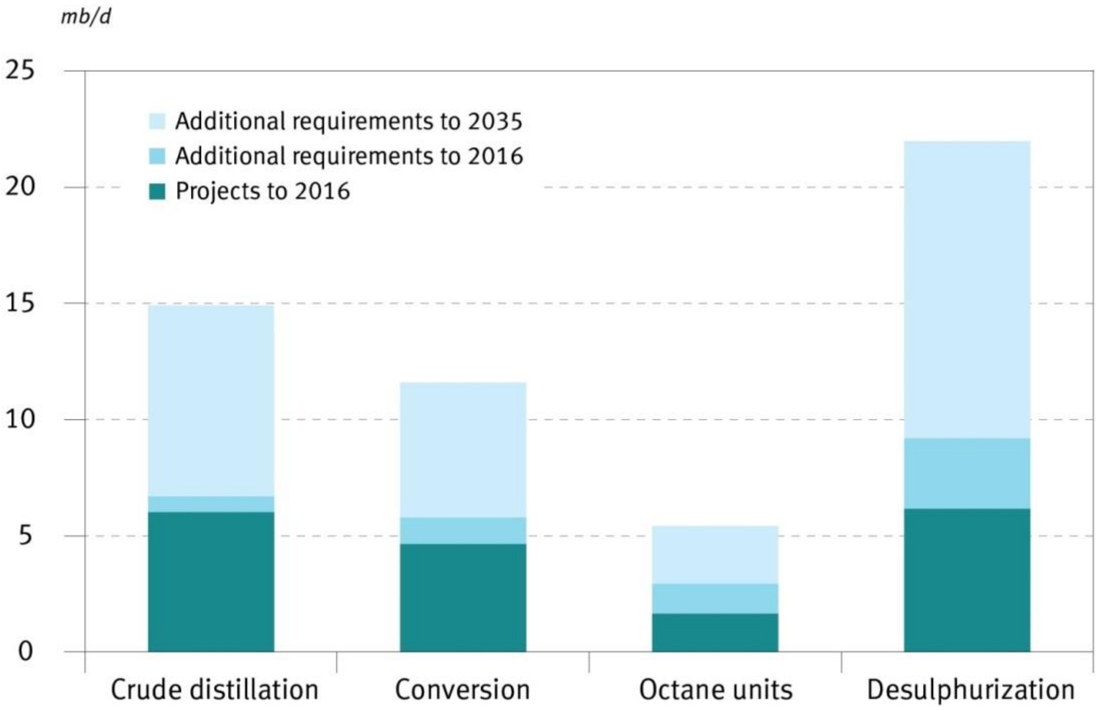

Figure 38 *Global capacity requirements by process type, 2011-2035 (OPEC, 2012)*

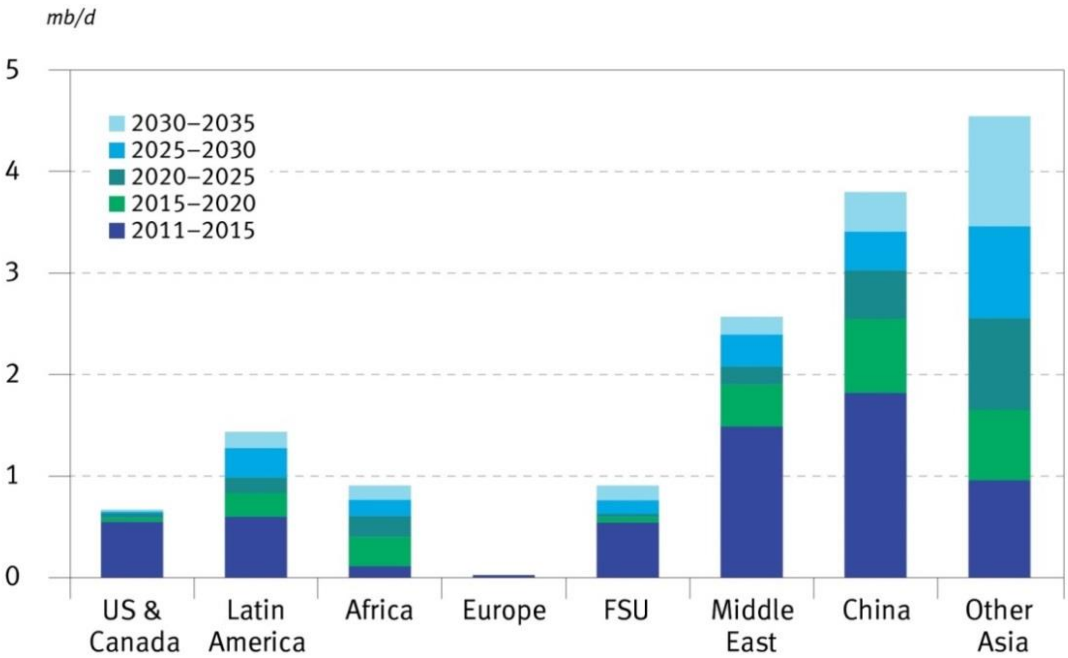

Figure 39 *Crude distillation capacity additions, 2011-2035 (OPEC, 2012)*

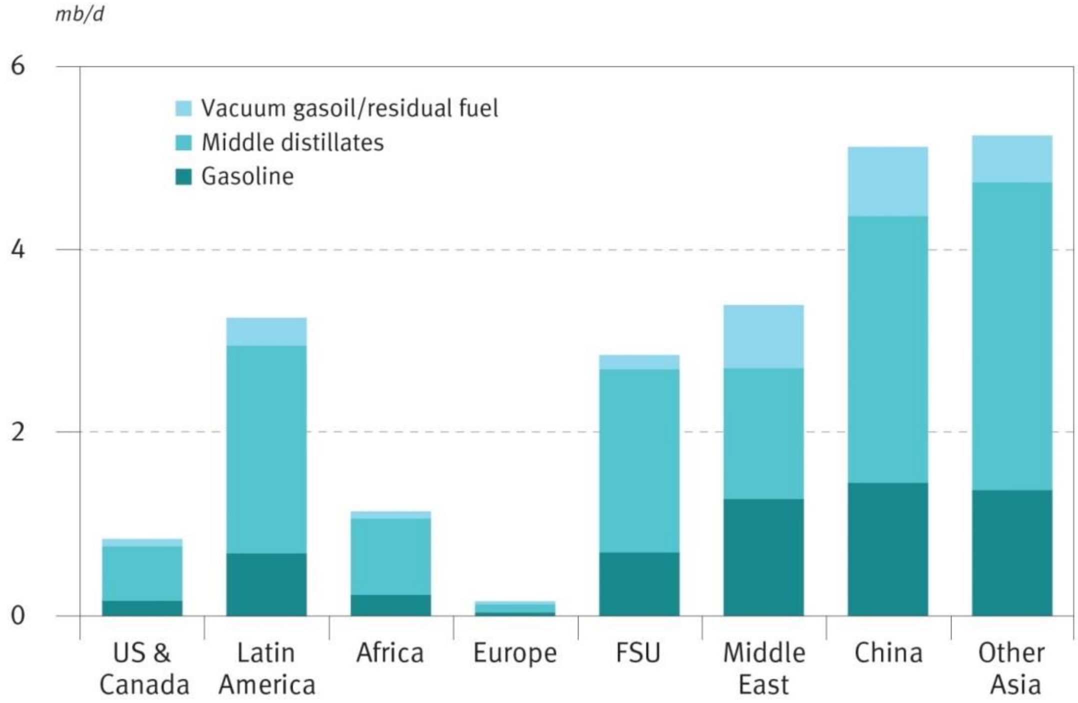

Figure 40 *Desulphurization capacity requirements by product and region, 2011-2035 (OPEC, 2012)*

15. Effect of organosulfur compounds on natural gas properties

Natural gases always have water associated with them, as they are saturated with water in the reservoir. When the hydrocarbons are extracted from underground water is also produced straight from the reservoir. Generally, the water contents of sour gases are defined as a molar average of the solubility of water in the hydrocarbons, hydrogen sulfide, and carbon dioxide (Robinson et al.,1977). The accurate prediction of equilibrium water contents of natural gases is extremely important, especially for sour gases.

Distinct knowledge of phase behavior in water – sour gas systems is essential when it comes to design and operation of production and refining facilities, as well as natural gas pipelines, as considerable amount of gases contain acid gases and water. By preventing the formation of condensed water the risk of related problems can be reduced (Mohammadi et al., 2005).

The first problem related with water content of sour gases is corrosion. The lifetime of natural gas pipelines is affected by the rate at which corrosion occurs. The second problem is the formation of hydrates due to the presence of water in natural gas. Hydrates formation leads to safety hazards to production/transportation/injection systems and to considerable economic risks. The last, but not the least problem is two-phase flow in pipelines (Bahadori, 2011).

The risk of the occurrence of the problems mentioned above can be increased if the gas contains even small amount of hydrogen sulfide or carbon dioxide. That is mainly because the solubility of water in H_2S and in CO_2 differs significantly from the solubility of water in hydrocarbon systems as shown on Figure 41 (Carroll, 2002). This fact can possibly be explained by the discrepancy of molecular structures of these compounds. For instance, hydrogen sulfide has higher polarity than hydrocarbon components found in natural gas because of the asymmetric arrangement of its atoms. Water is strongly polar material itself, as a hence, water will have higher solubility in materials with higher polarity (Lukacs & Robinson, 1963).

The mutual solubility of hydrogen sulfide and carbon dioxide differs substantially with system temperature and pressure. Thus, the presence of sour gas, such as H_2S, and the presence of acid gas, such as CO_2, in a natural gas mixture would result in a raise in the water content at any given temperature and pressure (Mohammadi, Samieyan, & Tohidi, 2005).

15.1 Pure components behavior

From the previous chapters it is known that the natural gas is a complex mixture. Each component of the natural gas represents unique characteristics which essentially influences on gas behavior. The graphical presentation of this theory is shown in Figure 41, which demonstrates how the water content of pure components of methane, carbon dioxide, and hydrogen sulfide changes with increasing pressure at 120ºF. It is undoubtedly that all three substances show the diversity of behavior that occurs.

It can be seen that at low pressures the water content does not differ considerably for all three components. Generally, at this low pressure the water content is a function of temperature and pressure. However, with increasing pressure the phase behavior for the three components starts to be different.

The water content of methane, which can be considered as sweet gas, steadily decreases as the pressure increases. When it comes to carbon dioxide, the water content declines until the pressure reaches 1000 psia, after that there is an opposite tendency and the water content increases again. Lastly, hydrogen sulfide liquefies. Because of this unique behavior the water content exhibits discontinuity. It should be noted that at lower temperatures CO_2 behaves similarly and liquefies too.

It is reasonable to assume that the characteristics of three pure components would be matched with the behavior of gas mixtures (Carroll, 2002). Sour gases which contain a little volume of CO_2 and H_2S will have the phase behavior in a similar manner to pure methane. The water content of these gas mixtures will be continually declining as a function of pressure. Acid gas mixtures will behave like pure CO_2, but they will not form a second liquid. Sour mixtures with high content of H_2S will behave almost like pure H_2S. These gases under certain value of pressure and temperature will be in a liquid phase (Carroll, 2002).

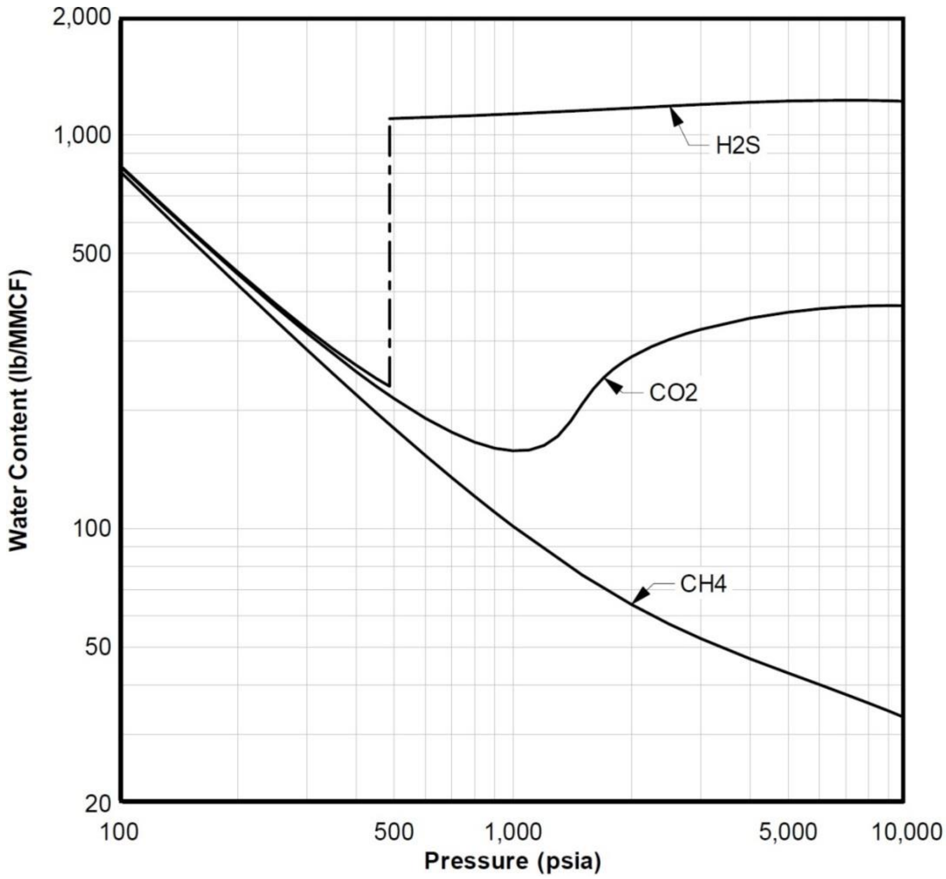

Figure 41 *Water content of three gases at 120℉ (50°C) (Carroll, 2002)*

15.2 Estimation of water content in sour gases

It is believed that sour/acid gases deteriorate the quality of natural gas by affecting the water content of those natural gases. In this subsection the water content of several gases with simplified content and existing gas fields is calculated using the AQUALIBRIUM software, version 3.01. There is a description of this software on the official website of FlowPhase®. There it says that AQUALIBRIUM is a software package for systems containing water, hydrogen sulfide, carbon dioxide, and light hydrocarbons. It has a well-deserved reputation for being amongst the most accurate software for equilibrium calculations in these systems, especially for acid gas + water systems.

First, the water content of natural gases with simplified composition was calculated. Only methane and hydrogen sulfide were taken into consideration to study the general behavior of those gases under three different conditions, reservoir, wellhead, and end-pipe conditions. The values of those parameters are generally accepted in natural gas production operations; moreover, it should be noted that there are other reservoir and surface pressure/temperature conditions.

Figure 42 presents the water content lines versus increasing hydrogen sulfide content of several gases. It is obvious that with increasing content of H_2S the water content also increases significantly. For instance, the gas with high sour content 75% H_2S carries 72% more water vapor as compared to sweeter gas with 15% H_2S.

The result also shows that the water depending on conditions starts to condense out of the gas. Under reservoir conditions the gas holds the largest amount of water, while under end-pipe conditions the water is decreased to a minimum level.

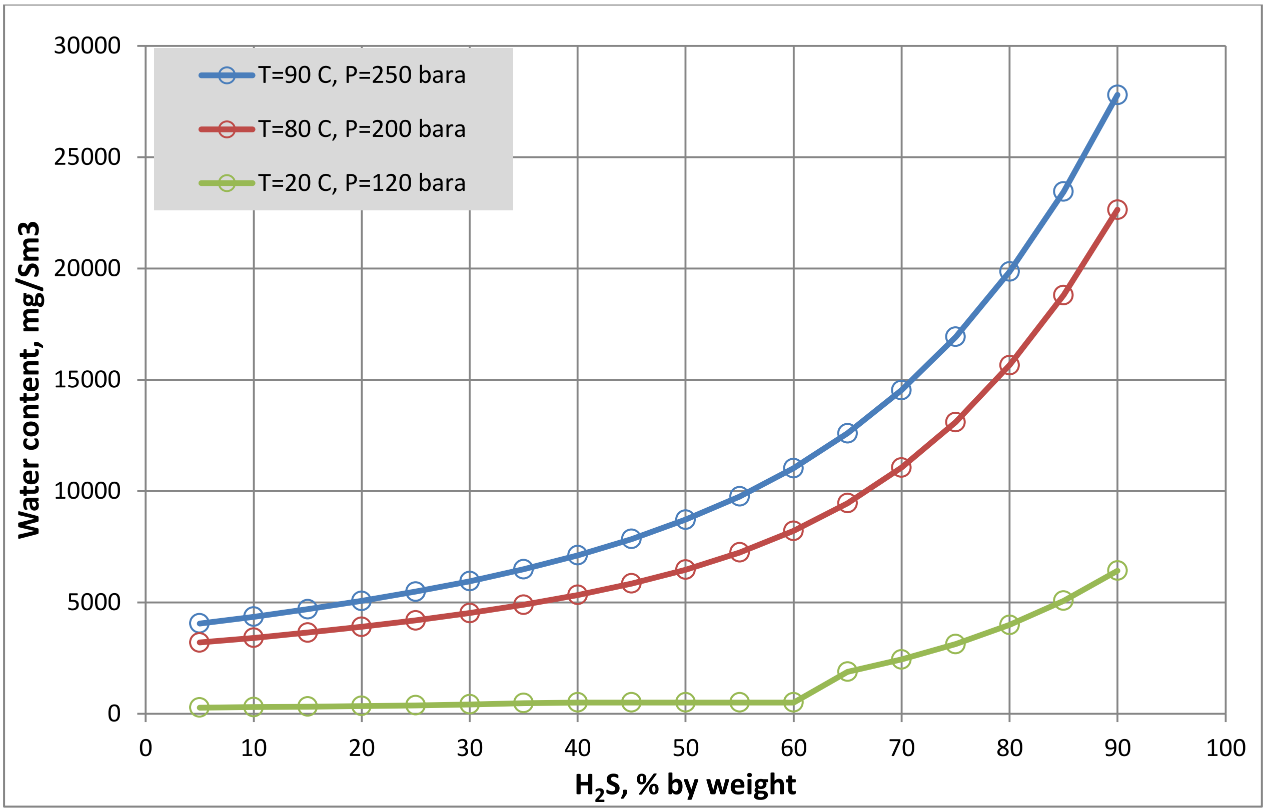

Figure 42 *Water content versus H_2S content of natural gases with simplified composition*

Table 17 *Water content of selected natural gases calculated with AQUALIBRIUM*

Conditions	Pressure, bara	Temperature, ºC	Water content, mg/Sm^3			
			Lacq	Kirkuk	Parentis	Kashagan
Reservoir	250	90	5196	4099	3612	5104
Wellhead	200	80	4004	3224	2867	3954
End pipe	120	20	359	282	240	372

Table 18 Composition of selected natural gases

Component	Lacq (France)	Kirkuk (Iraq)	Parentis (France)	Kashagan (Kazakhstan)
Methane	69.0	56.9	73.6	58.77
Ethane	3.0	21.2	10.2	9.01
Propane	0.9	6.0	7.6	4.54
Butanes	0.5	3.7	5.0	2.29
C_{5+}	0.1	1.6	3.6	1.49
Nitrogen	1.5	-	-	1.01
H2S	15.3	3.5	-	17.81
CO2	9.3	7.1	-	5.08

Table 17 gives the results on water content calculation for the gases from different parts of the world. The composition of the natural gases under studies is given in Table 18. It can be seen that sour gases from Lacq and Kashagan field exhibits undesirable behavior. The high sourness of these gases explains the higher values of water content in comparing with other sweeter gases from Kirkuk and Parentis fields. When it comes to pressure and temperature conditions, there is a common tendency for all four gases. The water vapor starts to condense out of the gas solution, and the water vapor values condensed at the wellhead equal to 1192 mg/Sm^3 and 1150 mg/Sm^3 for Lacq and Kashagan fields respectively, and at the end-pipe the values are 3645 mg/Sm^3 and 3582 mg/Sm^3 which is more or less the same.

It is of vital importance to know the amount of difference between the water content at reservoir conditions and the water condensed at the receiving terminal, as by knowing it the dehydration facilities can be designed and the formation of hydrates can be removed.

Table 19 *Water content of gases with simplified composition calculated by AQUALIBRIUM*

H_2S, weight %	$CH_{1,}$ weight %	Water content, mg/Sm^3	Water content, mg/Sm^3	Water content, mg/Sm^3
90	10	27796	22638	6421
85	15	23446	18802	5073
80	20	19860	15652	3990
75	25	16923	13096	3123
70	30	14533	11057	2431
65	35	12597	9456	1881
60	40	11030	8211	505
55	45	9757	7239	505
50	50	8712	6468	505
45	55	7844	5844	505
40	60	7113	5328	505
35	65	6489	4892	471
30	70	5950	4517	417
25	75	5478	4190	375
20	80	5061	3900	342
15	85	4690	3640	315
10	90	4355	3406	291
5	95	4052	3193	271

Summary

New petroleum product specifications have had profound impact on refineries' business philosophy worldwide. Petroleum companies are investing vast amount of money to introduce breakthrough technologies and to upgrade existing ones.

After in-depth analysis of existing commercial and semi-commercial desulphurization technologies it can be concluded that those technologies cannot satisfy the industry requirements and cannot be complied with the market needs. Conventional hydrodesulphurization is very expensive (desulphurization of 20,000 barrel of oil is as much as $40 million) and energy intensive sulfur removal technique. HDS operates at elevated temperatures (290 to 445˚C) and pressures (35 to 170 atm.), uses very costly hydrogen, removes only easy sulfur (hydrogen sulfide, thiols, etc.), and reduces the quality of refined products. As a hence, decreased energy is returned on energy invested and the impact on the environment is increased. Time and money being spent on research and development for the hydrodesulphurization could be better invested into developing alternative technologies.

It is known that organosulfur removal operations are implemented at surface conditions. But is it the only way to desulfurize hydrocarbon feeds? One of the revolutionary ideas is to develop in-situ or downhole sulfur capture technologies (*DoSCap* technology {Darkhan Duissenov}). Crude oil and natural gas with high sulfur content could be upgraded in the source rock and desulfurized before hydrocarbons are transported to surface. By implementing the *DoSCap* technology additional CAPEX and OPEX would be reduced considerably. The costs of lost time, the replacement of materials of construction, and the constant personnel involvement caused by corrosion, would be avoided. Finally, the commercial value of crude oil would be increased by about 10-15%.

However, the scientists involved in research of the problem under consideration are focused on more immediate challenges and working with currently available techniques and tools. One of the alternatives could be the integration of biodesulphurization process units into existing refineries. There are two options, first option is to put BDS before conventional HDS, and second option is to implement BDS after conventional HDS. In order to do so significant modification of current operations is needed. Biocatalytic desulphurization involves certain type of bacterial strain in order to selectively remove

sulfur compounds with high-boiling temperature (thiophenes, dibenzothiophenes, and their alkyl derivatives).

Another alternative is the implementation of combined technologies. In combined technologies the processes could be based on existing sulfur removal techniques, such as oxidative desulphurization, biocatalytic desulphurization, and hydrogenation processes. Furthermore, base technologies could be complemented by various physical forces and chemical reactions. Microwave energy, catalysis and hydrotreatment together can improve the effect of desulphurization and some results were already gained. Also the combination of ultrasonic/microwave and electrostatic fields with oxidative desulphurization will lead to improved process parameters and higher desulphurization rates (Lin et al., 2010).

What is clear for now is that the alternative technologies mentioned above certainly have barriers for commercialization, and most of them have been met with certain opposition within the petroleum industry. The situation threatens to become more challenging with increasing sulfur content trend. While novel technologies are being developed to remove the organosulfur compounds, there is little doubt that utilization of the sour resources will have a negative impact.

Conclusion

- The authorities and environmental agencies are trending down the level of sulfur in petroleum products worldwide. The main purpose of those regulations is to yield high quality fuels with sulfur content less than 10 ppm. It is expected that by 2025 the maximum allowable level of sulfur for gasoline(10 ppm in US & EU, 20 ppm in FSU, 25 ppm in the Middle East) and for diesel (10 ppm in US & EU, 15 ppm in FSU, 40 ppm in Latin America) will be reduced tremendously.
- Conventional HDS is a very, very expensive process which uses elevated pressures and elevated temperatures; moreover HDS is not highly efficient and consumes outrageous amount of energy, resulting in decreased energy returned on energy invested and the increased impact on the environment;
- Biocatalytic biodesulphurization is an effective tool in removal of heavy sulfur compounds as dibenzothiophenes and their alkyl derivatives. Biocatalyst converts dibenzothiophene into 2-hydroxybiphenyl and sulfate via 4S pathway without any change of fuel heating value.
- New integrated technologies such as BDS-OD-RA (desulphurization rate 85-95% for crude oil in anaerobic conditions, 94-95% in aerobic conditions), combined hydrogenation-biodesulphurization technologies (bacterial strains *Rhodococcus erythropolis*, *Arthrobacter paraffineus*, *Bacillus sphaericus*, *Rhodococcus rhodochrous*), desulphurization processes involving ultrasonic-catalytic oxidation (simple operation, low cost, low temperature, high efficiency) could be an excellent alternatives to conventional desulphurization technologies.
- Distinct knowledge of phase behavior in water – sour gas systems is essential when it comes to design and operation of production and refining facilities, as well as natural gas pipelines, as considerable amount of gases contain sour gases and water. By preventing the formation of condensed water the risk of related problems can be reduced.

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Appendices

Table 20 *Estimated proved reserves holders as of January 2013 (Rachovich, 2012)*

Rank	Country	Proved reserves (billion barrels)	Share of total
1.	Venezuela	297.6	18.2%
2.	Saudi Arabia	265.4	16.2%
3.	Canada	173.1	10.6%
4.	Iran	154.6	9.4%
5.	Iraq	141.4	8.6%
6.	Kuwait	101.5	6.2%
7.	UAE	97.8	6.0%
8.	Russia	80.0	5.0%
9.	Libya	48.0	2.9%
10.	Nigeria	37.2	2.3%
11.	Kazakhstan	30.0	1.8%
12.	China	25.6	1.6%
13.	Qatar	25.4	1.6%
14.	United States	20.7	1.3%
15.	Brazil	13.2	0.8%
16.	Algeria	12.2	0.7%
17.	Angola	10.5	0.6%
18.	Mexico	10.3	0.6%
19.	Ecuador	8.2	0.5%
20.	Azerbaijan	7.0	0.4%
21.	Oman	5.5	0.3%
22.	India	5.48	0.3%
23.	Norway	5.37	0.3%
World total		1,637.9	100
Total OPEC		1,204.7	73.6

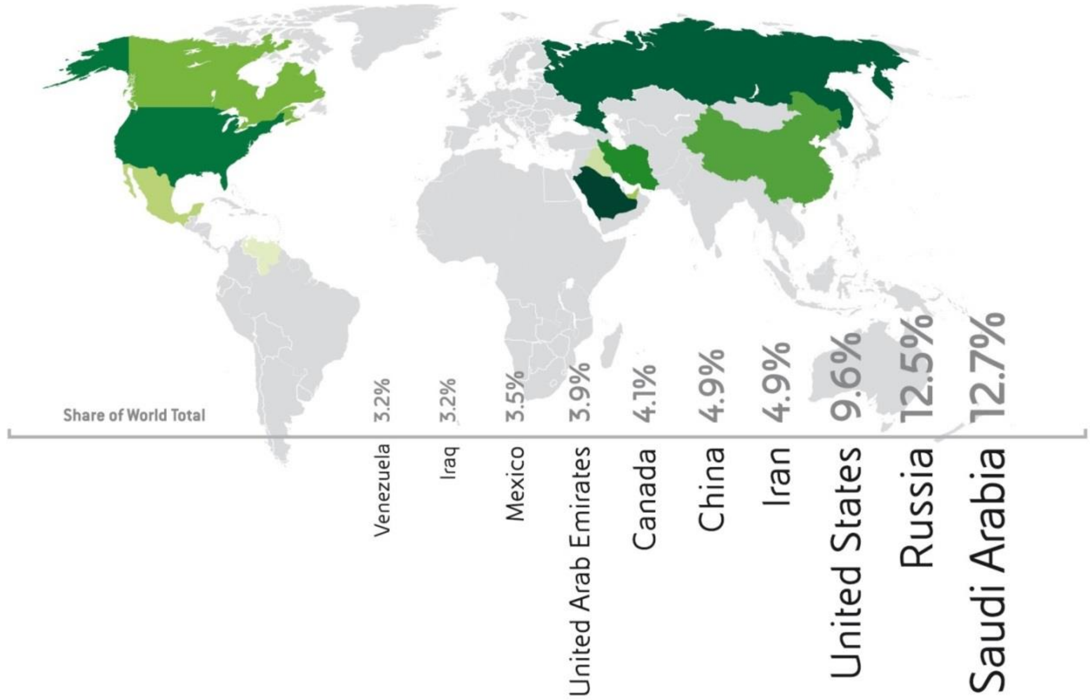

Figure 43 *The world top 10 oil producers (Eni, 2012)*

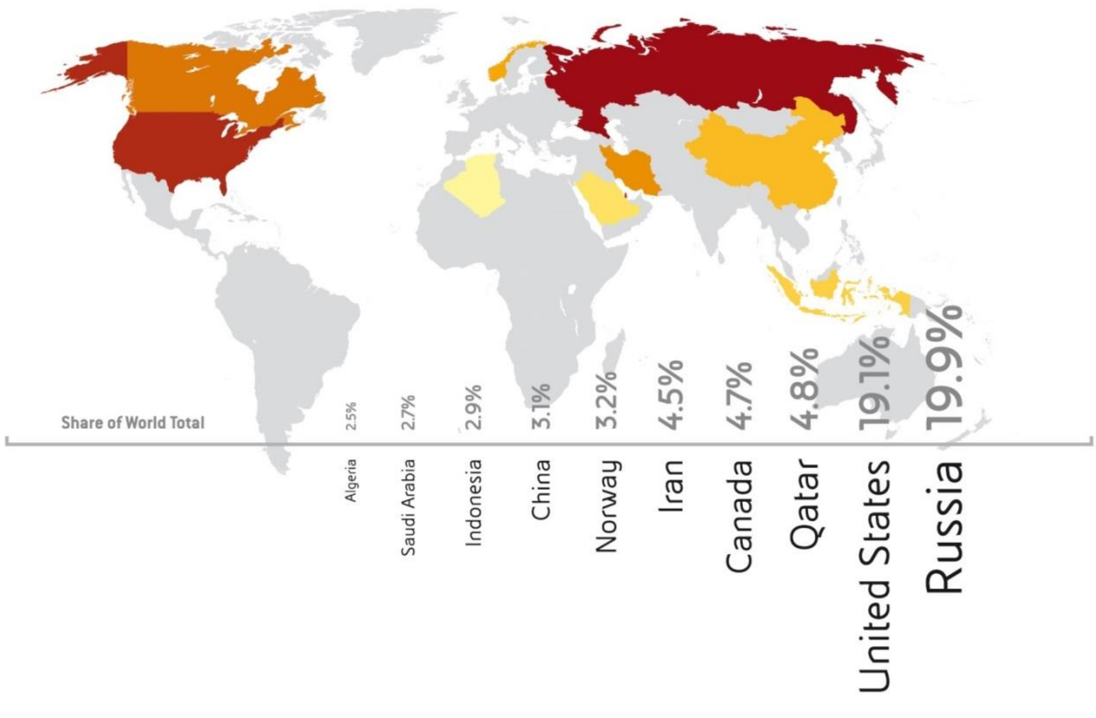

Figure 44 *The world top 10 natural gas producers (Eni, 2012)*

Table 21 *Crude production by gravity (thousand barrels/day) (Eni, 2012)*

	1995	2000	2005	2008	2009	2010	2011
World	**62,759**	**68,008**	**73,862**	**74,673**	**73,062**	**74,091**	**74,700**
Light	17,624	19,341	19,203	19,345	18,409	19,254	18,385
Medium	32,566	34,805	39,445	40,445	39,273	38,731	39,789
Heavy	6,440	8,052	9,922	9,698	9,768	10,370	10,508
Unassigned production	6,130	5,811	5,292	5,185	5,613	5,736	6,018
(percentage)							
Light	28.1	28.4	26.0	25.9	25.2	26.0	24.6
Medium	51.9	51.2	53.4	54.2	53.8	52.3	53.3
Heavy	10.3	11.8	13.4	13.0	13.4	14.0	14.1
Unassigned production	9.8	8.5	7.2	6.9	7.7	7.7	8.1

Table 22 *Crude production by sulfur content (thousand barrels/day) (Eni, 2012)*

	1995	2000	2005	2008	2009	2010	2011
World	**62,759**	**68,008**	**73,862**	**74,673**	**73,062**	**74,091**	**74,700**
Sweet	20,395	22,334	23,325	23,252	22,892	23,637	22,539
Medium Sour	4,946	6,042	6,593	8,225	8,477	8,681	8,757
Sour	31,288	33,821	38,653	38,010	36,080	36,036	37,386
Unassigned production	6,130	5,811	5,292	5,185	5,613	5,736	6,018
(percentage)							
Sweet	32.5	32.8	31.6	31.1	31.3	31.9	30.2
Medium Sour	7.9	8.9	8.9	11.0	11.6	11.7	11.7
Sour	49.9	49.7	52.3	50.9	49.4	48.6	50.0
Unassigned production	9.8	8.5	7.2	6.9	7.7	7.7	8.1

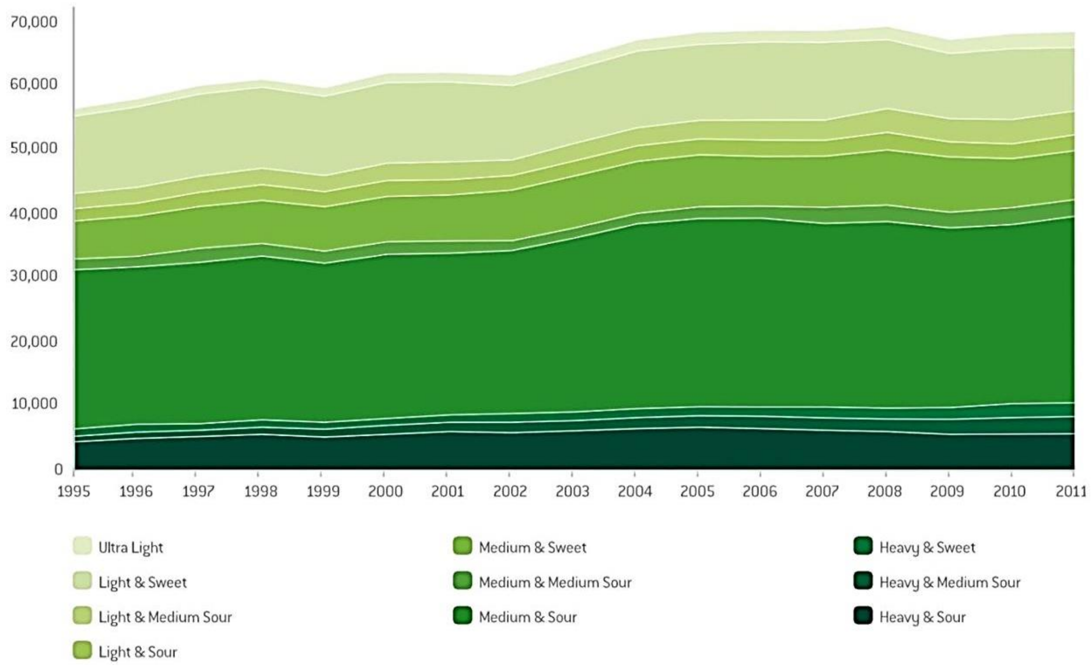

Figure 45 *Worldwide crude production by quality (thousand barrels/day) (Eni, 2012)*

Table 23** Main features of some qualities of crude oil (benchmarks in* ***bold*) (Maugeri, 2006)*

Name	Origin	Daily production (thousand barrels)	API degree	Sulfur content (%)
Brent blend	**United Kingdom**	**300**	**38.7**	**0.31**
Forties	United Kingdom	650	37.3	0.40
Ekofisk	Norway	500	37.8	0.22
Statfjord	Norway	480	37.7	0.29
WTI Blend	**United States**	**300**	**38.7**	**0.45**
Alaskan North Slope	United States	950	31	1
Light Louisiana	United States	400	38.7	0.13
West Texas Sour	United States	775	34.2	1.30
BCF-17	Venezuela	800	16.5	2.5
Maya	Mexico	2,450	21.6	3.6
Isthmus	Mexico	500	32.8	1.4
Olmeca	Mexico	400	39.3	0.8
Urals	Russia	3,200	32	1.30
Siberian Light	Russia	100	35.6	0.46
Arabian Light	**Saudi Arabia**	**5,000**	**33.4**	**1.80**
Arabian Extra Light	Saudi Arabia	1,200	37	1.33
Arabian Medium	Saudi Arabia	1,500	30.3	2.45
Arabian Heavy	Saudi Arabia	800	28.7	2.8
Basrah Light	Iraq	1,600	30.2	2.6
Kirkuk	Iraq	350	33.3	2.3
Iran Heavy	Iran	1,700	30	2
Iran Light	Iran	1,300	33.4	1.6
Kuwait	Kuwait	2,000	31	2.63
Dubai	**Dubai**	**100**	**31.4**	**2**
Bonny Light	**Nigeria**	**450**	**34.3**	**0.15**
Forcados	Nigeria	400	30.4	0.18
Escavros	Nigeria	300	34.4	0.15
Cabina	Angola	300	32	0.12
Palanca	Angola	200	37	0.17
Brega	Libya	120	42	0.20
Bu Attifel	Libya	100	43	0.03
Es Sider	Libya	300	36.6	0.42
Saharan Blend	Algeria	350	47	0.11
Tapis	**Malaysia**	**300**	**45.2**	**0.03**
Daquing	China	1,000	32.2	0.09
Shengli	China	550	26	0.76

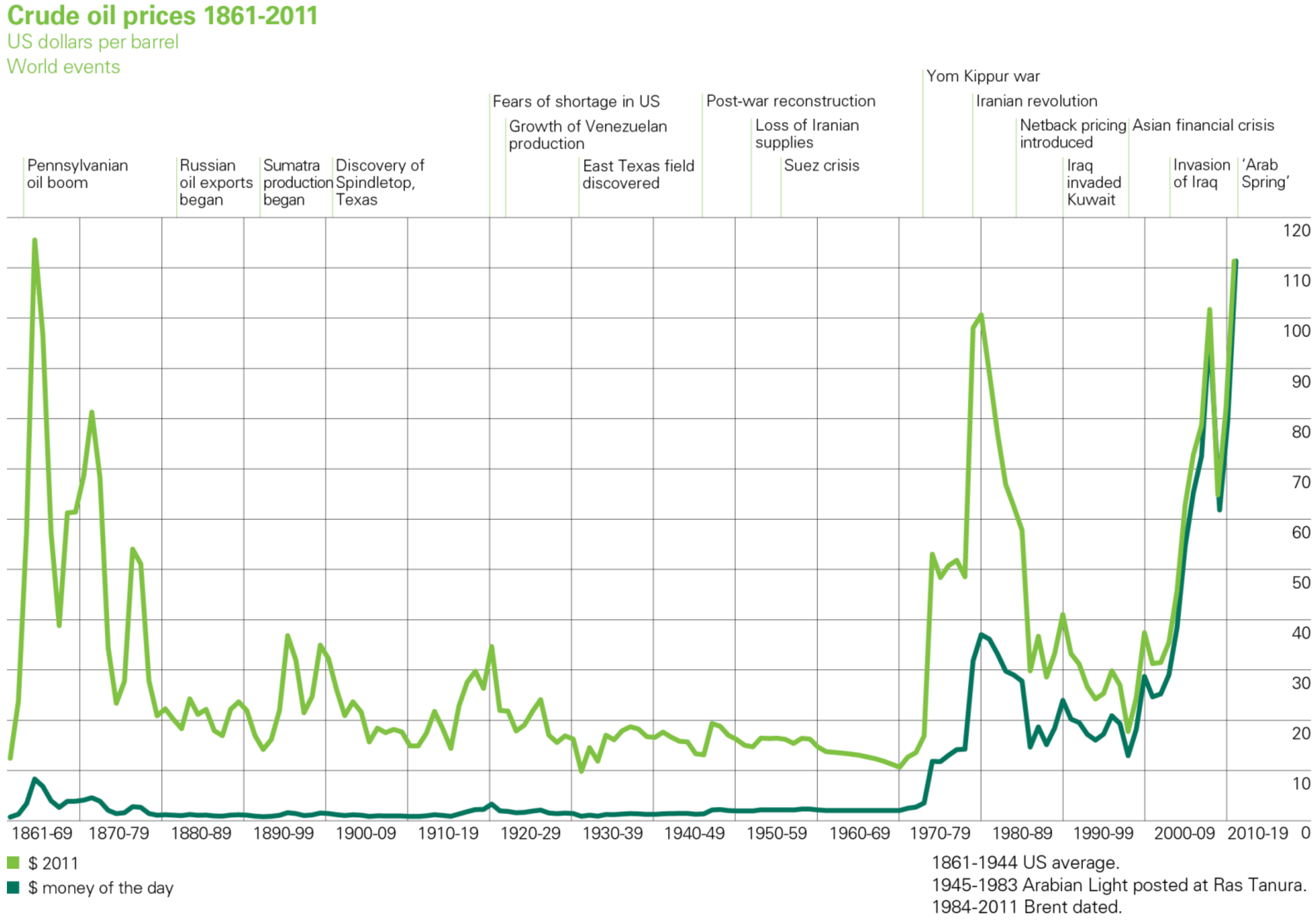

Figure 46 *Historical crude oil prices, 1861-2011 (BP, 2012)*

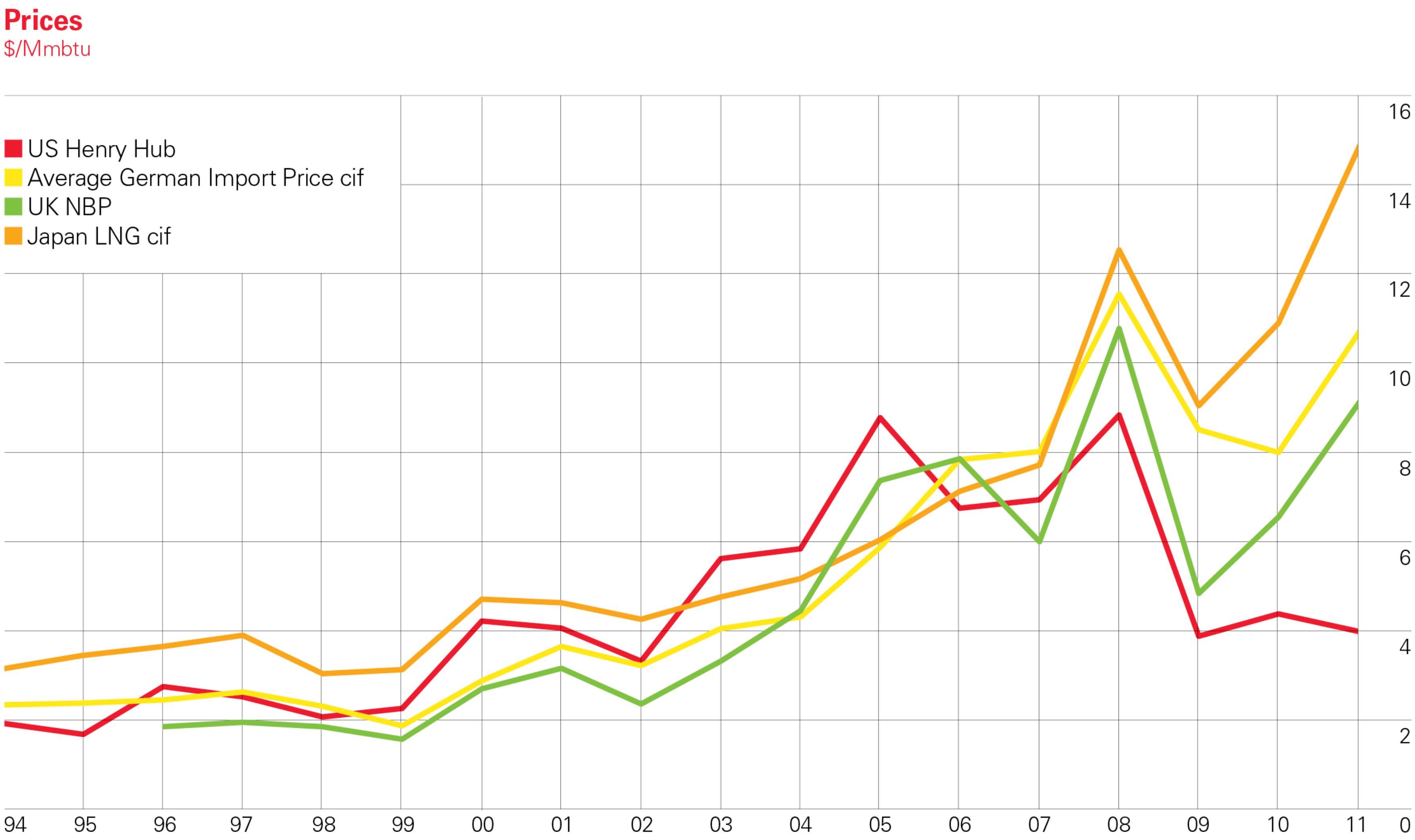

Figure 47 *Historical natural gas prices, 1994-2011 (BP, 2012)*

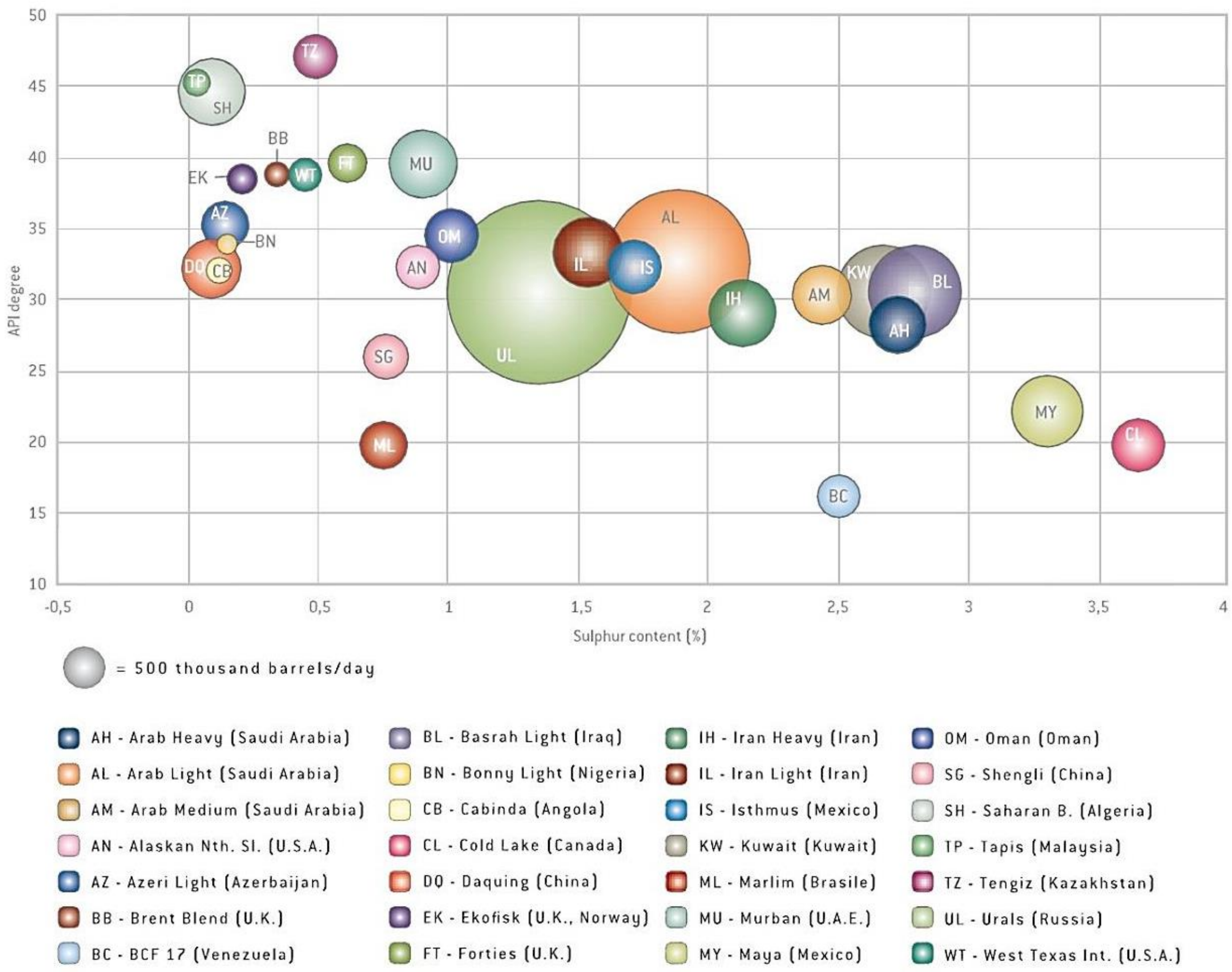

***Figure 48** Quality and production volume of main crudes (thousand barrels/day) (Eni, 2011)*

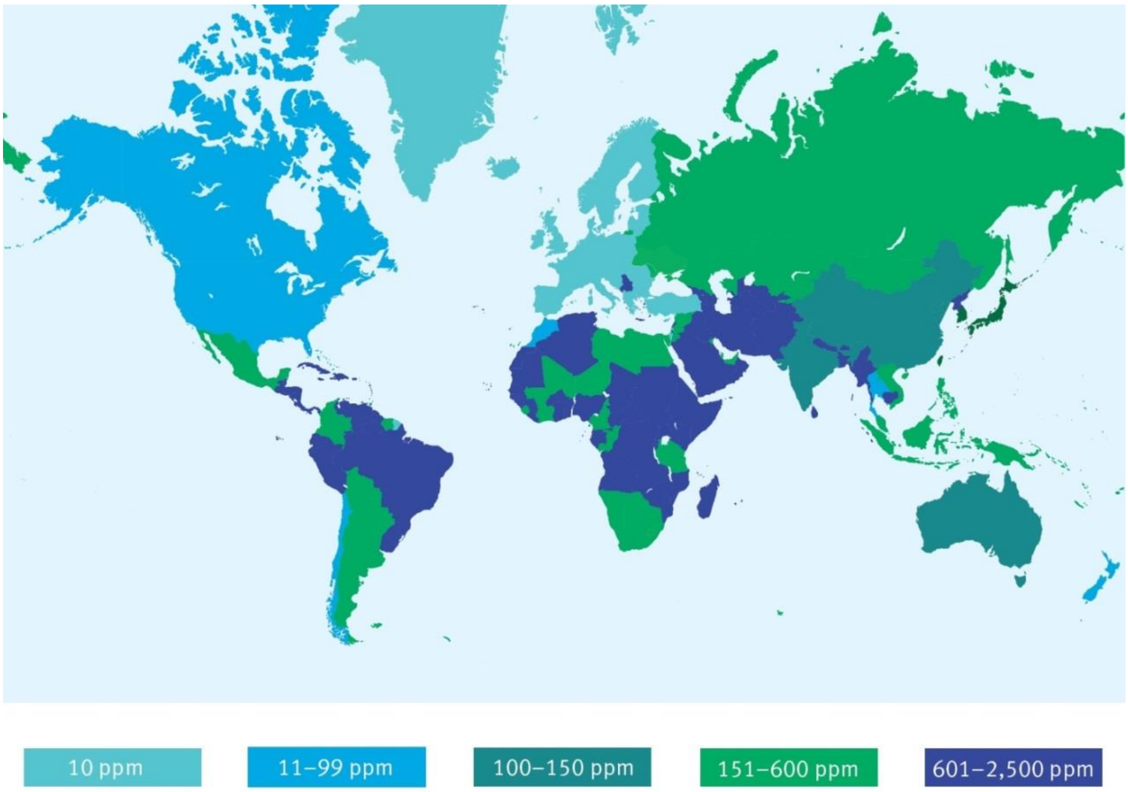

Figure 49 *Maximum gasoline sulfur limits as of September 2012 (OPEC, 2012)*

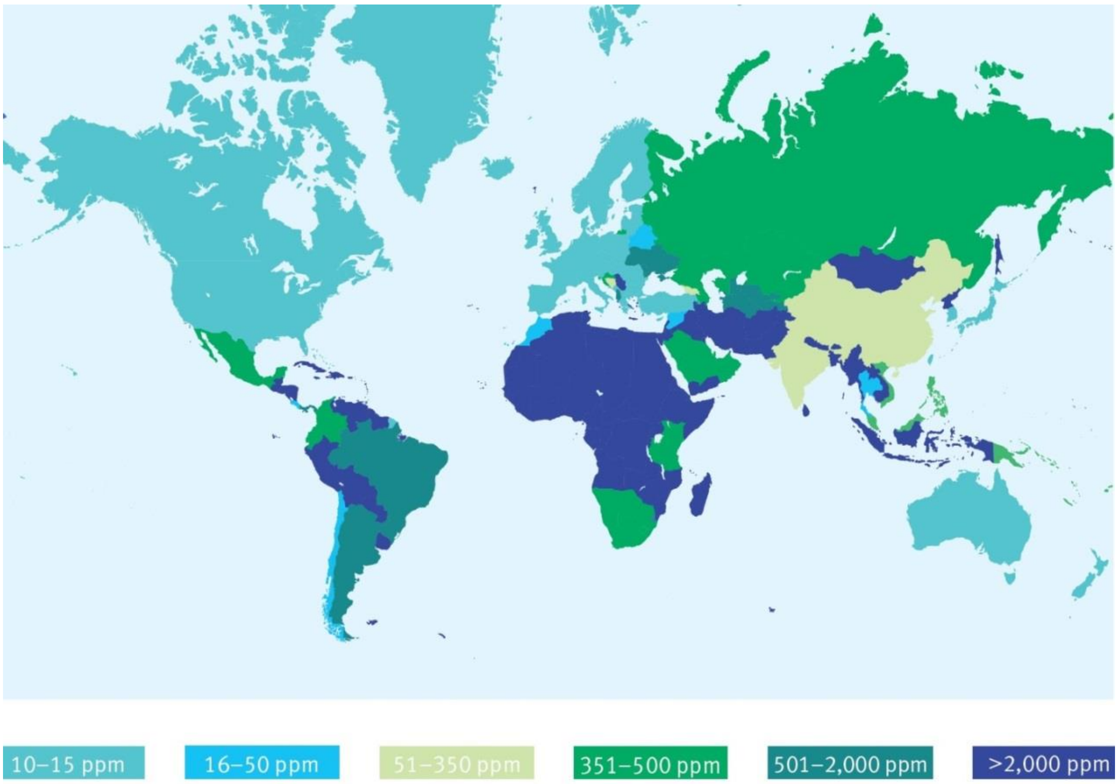

Figure 50 *Maximum on-road diesel sulfur limits as of September 2012 (OPEC, 2012)*

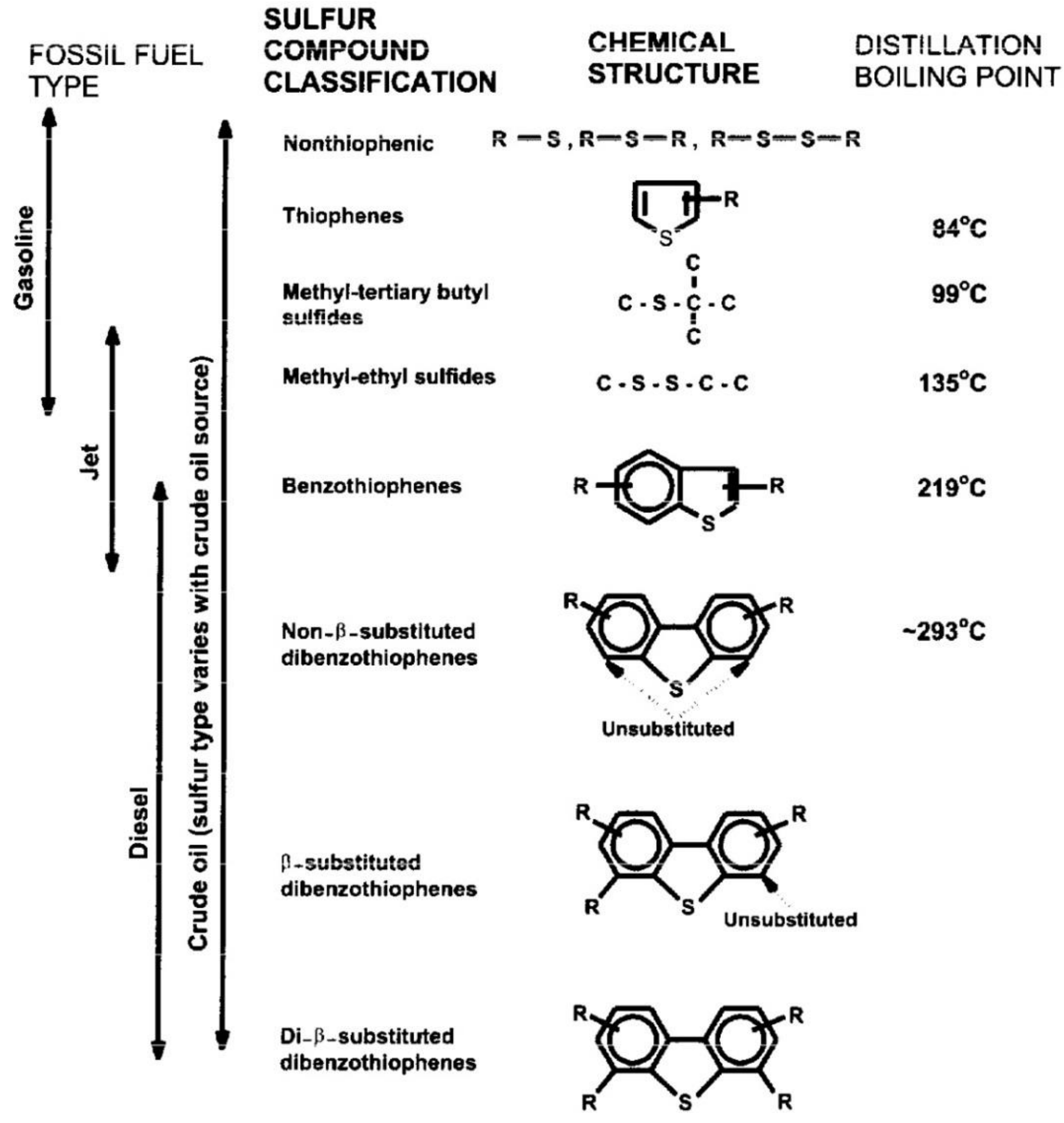

Figure 51 *Examples of organosulfur compounds present in fossil fuels (McFarland, 1999)*

Table 24 *Effect of hydrotreatment on the characteristics of gas oil (Wauquier, 1995)*

Product designation	A	A+	A++	A+++	A++++
Density, kg/l at 15˚C	0.862	0.850	0.849	0.838	0.827
Viscosity at 20˚C, mm^2/s	5.55	5.34	5.22	5.12	4.90
Sulfur content, ppm	11,600	640	230	22	4
Nitrogen content, ppm	216	150	135	17	0.2
Cetane number	49.0	50.4	49.0	53.9	60.2
Composition, weight %					
Paraffins	36.5	36.2	36.8	37.0	41.4
Naphthenes	24.3	24.5	36.5	37.7	51.8
Monoaromatics	14.2	23.1	21.9	20.2	6.0
Diaromatics	15.4	12.8	12.6	4.5	0.8
Triaromatics	1.8	1.0	0.9	0.4	0.0
Thiophenes	7.7	2.4	1.4	0.3	0.0
Total aromatics	39.1	39.3	36.8	25.4	6.8

Table 25 *Overview of petroleum refining processes (OSHA, 1999)*

Process name	Action	Method	Purpose	Feedstock	Product
Fractional processes					
Atmospheric distillation	Separation	Thermal	Separate fractions	Desalted crude oil	Gas, gas oil, distillate, residual
Vacuum distillation	Separation	Thermal	Separate w/o cracking	Atmospheric tower residua	Gas oil, lube stock, residual
Conversion processed-decomposition					
Catalytic cracking	Alteration	Catalytic	Upgrade gasoline	Gas oil, coke distillate	Gasoline, petrochemical feedstock
Coking	Polymerize	Thermal	Convert vacuum residuals	Gas oil, coke distillate	Gasoline, petrochemical feedstock
Hydro-cracking	Hydrogenate	Catalytic	Convert to lighter HC's	Gas oil, cracked oil, residual	Lighter, higher-quality products
Visbreaking	Decompose	Thermal	Reduce viscosity	Atmospheric tower residual	Distillate, tar
Conversion processes-unification					
Alkylation	Combining	Catalytic	Unite olefins & isoparaffins	Tower isobutane/ cracker olefin	Iso-octane (alkylate)
Grease compounding	Combining	Thermal	Combine soaps & oils	Lube oil, fatty acid, alky metal	Lubricating grease
Polymerizing	Polymerize	Catalytic	Unite 2 or more olefins	Cracker olefins	High-octane naphtha, petrochemical stocks
Conversion processes-alteration or rearrangement					
Catalytic reforming	Alteration/ dehydration	Catalytic	Upgrade low-octane naphtha	Coker/ hydro-cracker naphtha	High octane reformate/ aromatic

Isomerization	Rearrange	Catalytic	Convert straight chain to branch	Butane, pentane, hexane	Isobutane/ pentane/ hexane
Treatment processes					
Amine treating	Treatment	Absorption	Remove acidic contaminants	Sour gas, HCs w/CO_2 & H_2S	Acid free gases & liquid HCs
Desalting	Dehydration	Absorption	Remove contaminants	Crude oil	Desalted crude oil
Drying & sweetening	Treatment	Absorption /thermal	Remove H_2O & sulfur compounds	Liquid HCs, LPG, alkyl feedstock	Sweet & dry hydrocarbons
Furfural extraction	Solvent extraction	Absorption	Upgrade mid distillate & lubes	Cycle oils & lube feed-stocks	High quality diesel & lube oil
Hydrodesulphurization	Treatment	Catalytic	Remove sulfur, contaminants	High-sulfur residual/ gas oil	Desulfurized olefins
Hydrotreating	Hydrogenation	Catalytic	Remove impurities, saturate HC's	Residuals, cracked HC's	Cracker feed, distillate, lube
Phenol extraction	Solvent extraction	Absorption /thermal	Improve viscosity index, color	Lube oil base stocks	High quality lube oils
Solvent deasphalting	Treatment	Absorption	Remove asphalt	Vacuum tower residual, propane	Heavy lube oil, asphalt
Solvent dewaxing	Treatment	Cool/ filter	Remove wax from lube stocks	Vacuum tower lube oils	Dewaxed lube basestock
Solvent extraction	Solvent extraction	Absorption/ precipitation	Separate unsat. oils	Gas oil, reformate, distillate	High-octane gasoline
Sweetening	Treatment	Catalytic	Remove H_2S, convert mercaptan	Untreated distillate/gasoline	High-quality distillate/gasoline

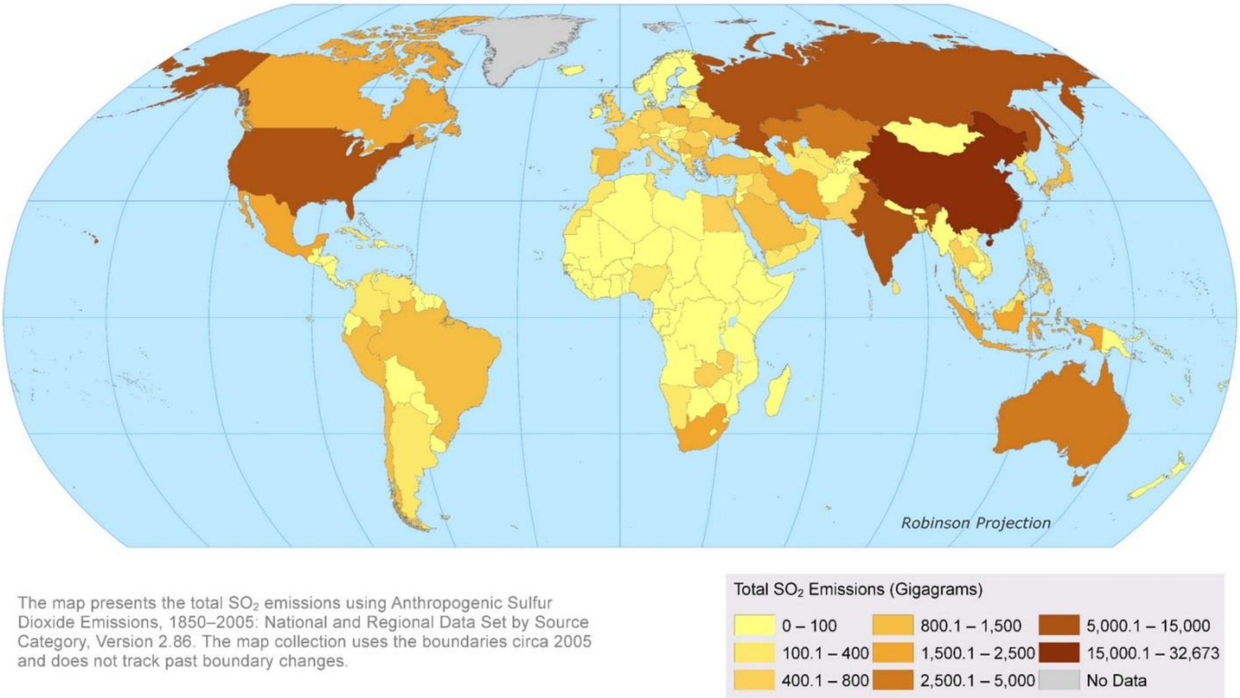

Figure 52 *Worldwide total SO_2 emissions as of 2005 (NASA, 2005)*

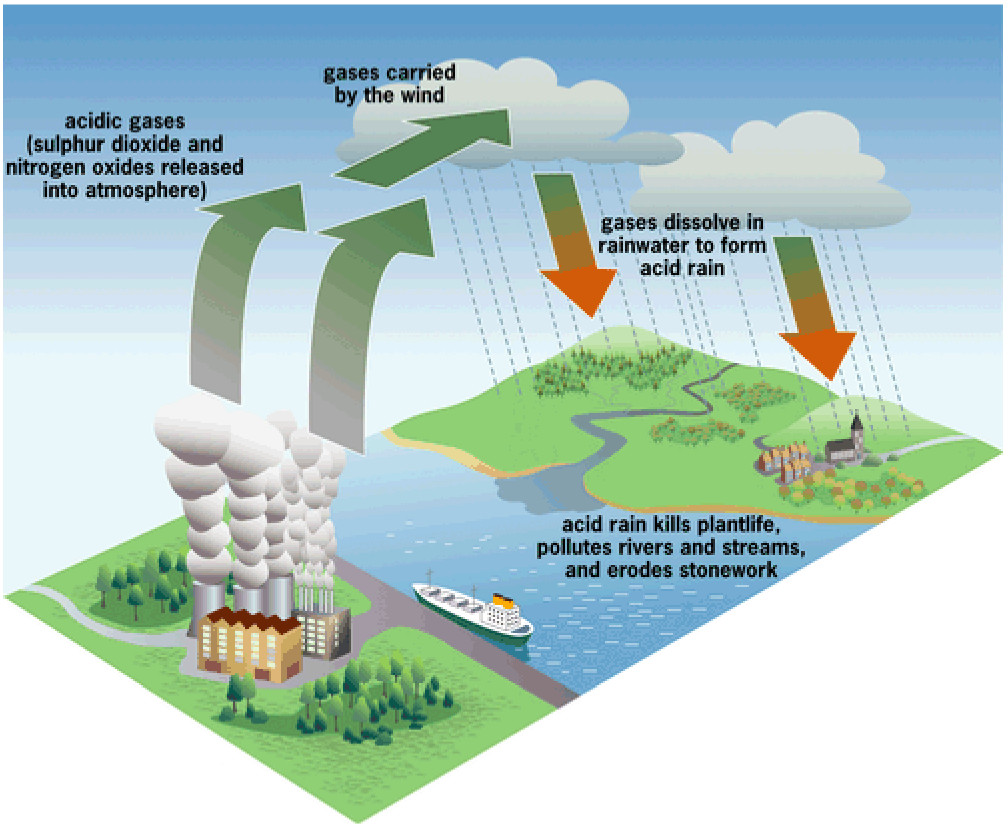

Figure 53 *Acid rain formation (McDonald, 2009)*

ATSDR
AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY

HYDROGEN SULFIDE

CAS # 7783-06-4

Division of Toxicology and Environmental Medicine ToxFAQs™ July 2006

This fact sheet answers the most frequently asked health questions (FAQs) about hydrogen sulfide. For more information, call the ATSDR Information Center at 1-888-422-8737. This fact sheet is one in a series of summaries about hazardous substances and their health effects. It is important you understand this information because this substance may harm you. The effects of exposure to any hazardous substance depend on the dose, the duration, how you are exposed, personal traits and habits, and whether other chemicals are present.

HIGHLIGHTS: Hydrogen sulfide occurs naturally and is also produced by human activities. Just a few breaths of air containing high levels of hydrogen sulfide gas can cause death. Lower, longer-term exposure can cause eye irritation, headache, and fatigue. Hydrogen sulfide has been found in at least 35 of the 1,689 National Priorities List sites identified by the U.S. Environmental Protection Agency (EPA).

What is hydrogen sulfide?

Hydrogen sulfide (H_2S) occurs naturally in crude petroleum, natural gas, volcanic gases, and hot springs. It can also result from bacterial breakdown of organic matter. It is also produced by human and animal wastes. Bacteria found in your mouth and gastrointestinal tract produce hydrogen sulfide from bacteria decomposing materials that contain vegetable or animal proteins. Hydrogen sulfide can also result from industrial activities, such as food processing, coke ovens, kraft paper mills, tanneries, and petroleum refineries.

Hydrogen sulfide is a flammable, colorless gas with a characteristic odor of rotten eggs. It is commonly known as hydrosulfuric acid, sewer gas, and stink damp. People can smell it at low levels.

What happens to hydrogen sulfide when it enters the environment?

❏ Hydrogen sulfide is released primarily as a gas and spreads in the air.
❏ Hydrogen sulfide remains in the atmosphere for about 18 hours.
❏ When released as a gas, it will change into sulfur dioxide and sulfuric acid.
❏ In some instances, it may be released as a liquid waste from an industrial facility.

How might I be exposed to hydrogen sulfide?

❏ You may be exposed to hydrogen sulfide from breathing contaminated air or drinking contaminated water.
❏ Individuals living near a wastewater treatment plant, a gas and oil drilling operation, a farm with manure storage or livestock confinement facilities, or a landfill may be exposed to higher levels of hydrogen sulfide.
❏ You can be exposed at work if you work in the rayon textiles, petroleum and natural gas drilling and refining, or wastewater treatment industries. Workers on farms with manure storage pits or landfills can be exposed to higher levels of hydrogen sulfide.
❏ A small amount of hydrogen sulfide is produced by bacteria in your mouth and gastrointestinal tract.

How can hydrogen sulfide affect my health?

Exposure to low concentrations of hydrogen sulfide may cause irritation to the eyes, nose, or throat. It may also cause difficulty in breathing for some asthmatics. Brief exposures to high concentrations of hydrogen sulfide (greater than 500 ppm) can cause a loss of consciousness and possibly death. In most cases, the person appears to regain consciousness without any other effects. However, in many individuals, there may be permanent or long-term effects such as headaches, poor attention span, poor memory, and poor motor function. No health effects have been found in humans exposed to typical environmental concentrations of hydrogen sulfide (0.00011–0.00033 ppm).

Scientists have no reports of people poisoned by ingesting hydrogen sulfide. Pigs that ate feed containing hydrogen sulfide experienced diarrhea for a few days and lost weight after about 105 days.

Scientists have little information about what happens when you are exposed to hydrogen sulfide by getting it on your skin, although they know that care must be taken with the compressed liquefied product to avoid frost bite.

How likely is hydrogen sulfide to cause cancer?

Hydrogen sulfide has not been shown to cause cancer in humans, and its possible ability to cause cancer in animals has not been studied thoroughly. The Department of Health and Human Services (DHHS), the International Agency for Research on Cancer (IARC), and the EPA have not classified hydrogen sulfide for carcinogenicity.

How can hydrogen sulfide affect children?

Children are likely to be exposed to hydrogen sulfide in the same manner as adults, except for adults at work. However, because hydrogen sulfide is heavier than air and because children are shorter than adults, children sometimes are exposed to more hydrogen sulfide than adults. Health problems in children who have been exposed to hydrogen sulfide have not been studied much. Exposed children probably will experience effects similar to those experienced by exposed adults. Whether children are more sensitive to hydrogen sulfide than adults or whether hydrogen sulfide causes birth defects in people is not known.

How can families reduce the risk of exposure to hydrogen sulfide?

Families can be exposed if they live near natural or industrial sources of hydrogen sulfide, such as hot springs, manure holding tanks, or pulp and paper mills. Families may want to restrict visits to these places.

Is there a medical test to show whether I've been exposed to hydrogen sulfide?

Hydrogen sulfide can be measured in exhaled air, but samples must be taken within 2 hours after exposure to be useful. A more reliable test to determine if you have been exposed to hydrogen sulfide is the measurement of thiosulfate levels in urine. This test must be done within 12 hours of exposure. Both tests require special equipment, which is not routinely available in a doctor's office. Samples can be sent to a special laboratory for the tests. These tests can tell whether you have been exposed to hydrogen sulfide, but they can not determine exactly how much hydrogen sulfide you have been exposed to or whether harmful effects will occur.

Has the federal government made recommendations to protect human health?

The Occupational Safety and Health Administration (OSHA) has set an acceptable ceiling limit for hydrogen sulfide of 20 parts hydrogen sulfide per 1 million parts of air (20 ppm) in the workplace.

The National Institute for Occupational Safety and Health (NIOSH) recommends a 10-minute ceiling limit of 10 ppm in the workplace.

Reference

Agency for Toxic Substances and Disease Registry (ATSDR). 2006. Toxicological Profile for Hydrogen Sulfide (Update). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service.

Where can I get more information? For more information, contact the Agency for Toxic Substances and Disease Registry, Division of Toxicology and Environmental Medicine, 1600 Clifton Road NE, Mailstop F-32, Atlanta, GA 30333. Phone: 1-888-422-8737, FAX: 770-488-4178. ToxFAQs Internet address via WWW is http://www.atsdr.cdc.gov/toxfaq.html. ATSDR can tell you where to find occupational and environmental health clinics. Their specialists can recognize, evaluate, and treat illnesses resulting from exposure to hazardous substances. You can also contact your community or state health or environmental quality department if you have any more questions or concerns.

CALIFORNIA CRUDE OIL PRODUCTION AND IMPORTS

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STAFF PAPER

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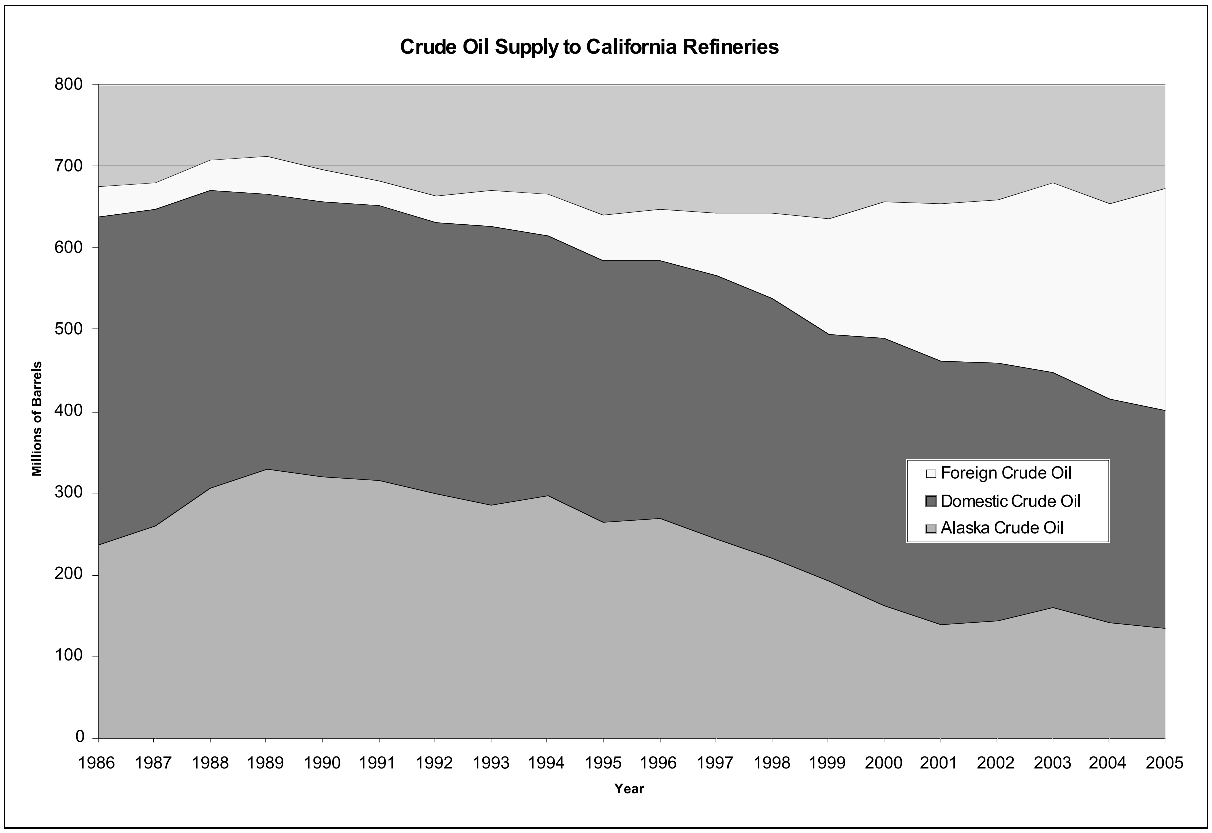
CALIFORNIA CRUDE OIL PRODUCTION AND IMPORTS

Introduction

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

Figure 1



Source: Petroleum Industry Information Reporting Act

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

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

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

Crude Oil Characteristics

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

Specific Gravity

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

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

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

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

Sulfur Content

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

Acid Content

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

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

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

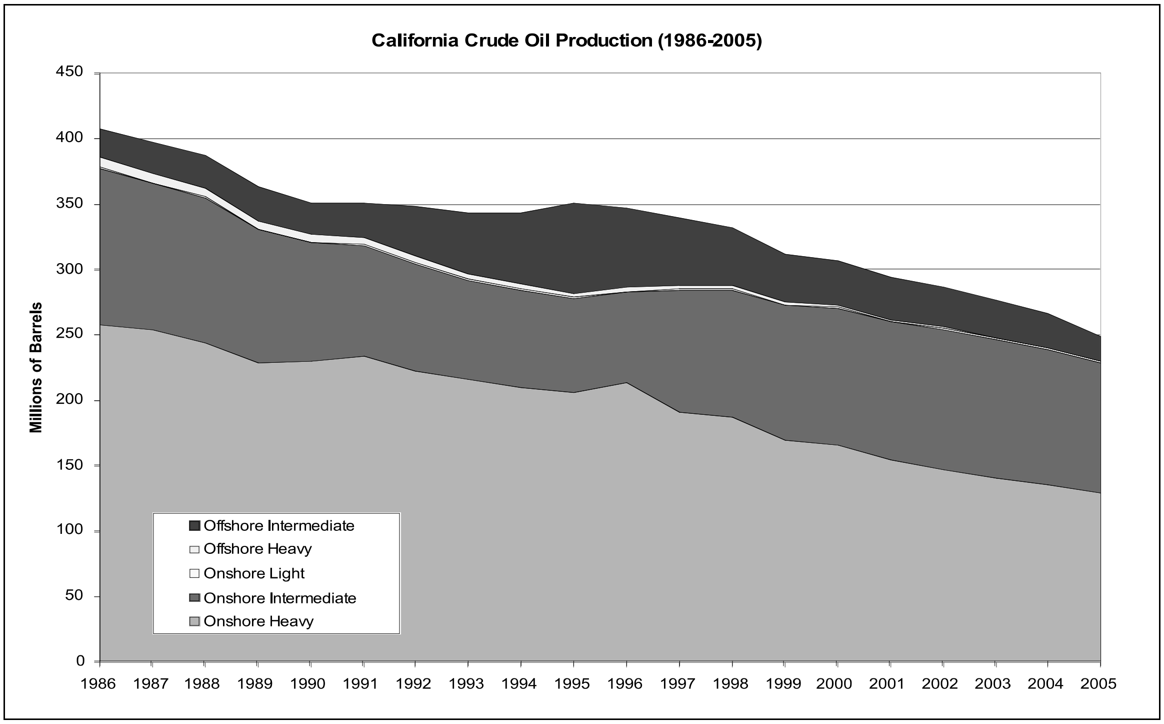
California Crude Oil Production

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

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

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

Figure 2



Sources: California Department of Conservation, Minerals Management Service

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

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

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

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

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

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

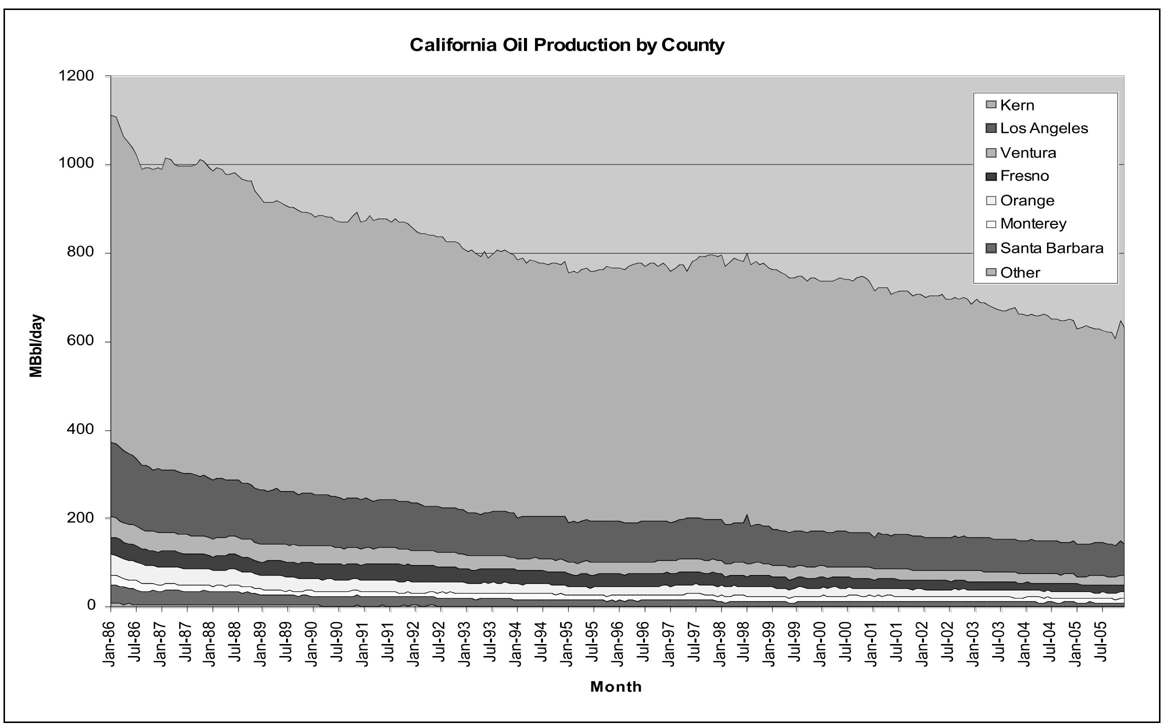
Table 1 shows an assay of selected California crude oils.[12] The table provides the percentages of 2005 production to show the relative importance of the field. The distillation breakdown of each crude oil provides a general guideline of the refining product suite that would result after the initial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

Table 1

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

Figure 3 shows the onshore production by county.

Figure 3



Source: Dept. of Conservation

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

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

Alaska North Slope Crude Oil

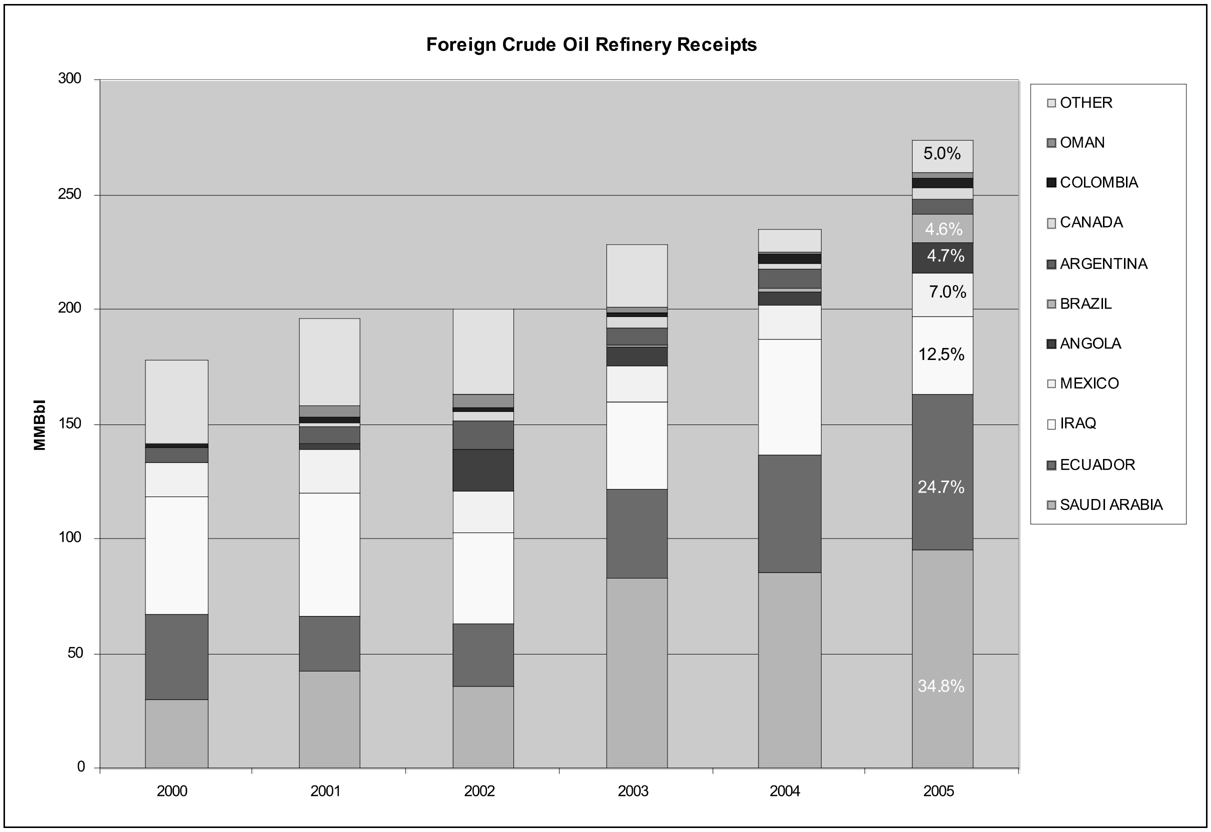
In 2005, California imported 21 percent of its total crude oil supply from Alaska. Oil fields in Alaska's North Slope produce a wide range of crude oils. API gravities from different fields range from 22 to 40 degrees. Alaskan refineries located along the Trans Alaska Pipeline System (TAPS) "top" the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

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

Foreign Crude Oil Imports

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

Figure 4



Source: Energy Information Administration

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

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

Table 2

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

Source: Office of Safety and Health Administration

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

Crude Oil Supply and Distribution to California Refineries

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

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

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

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

Figure 5

Source: California Energy Commission

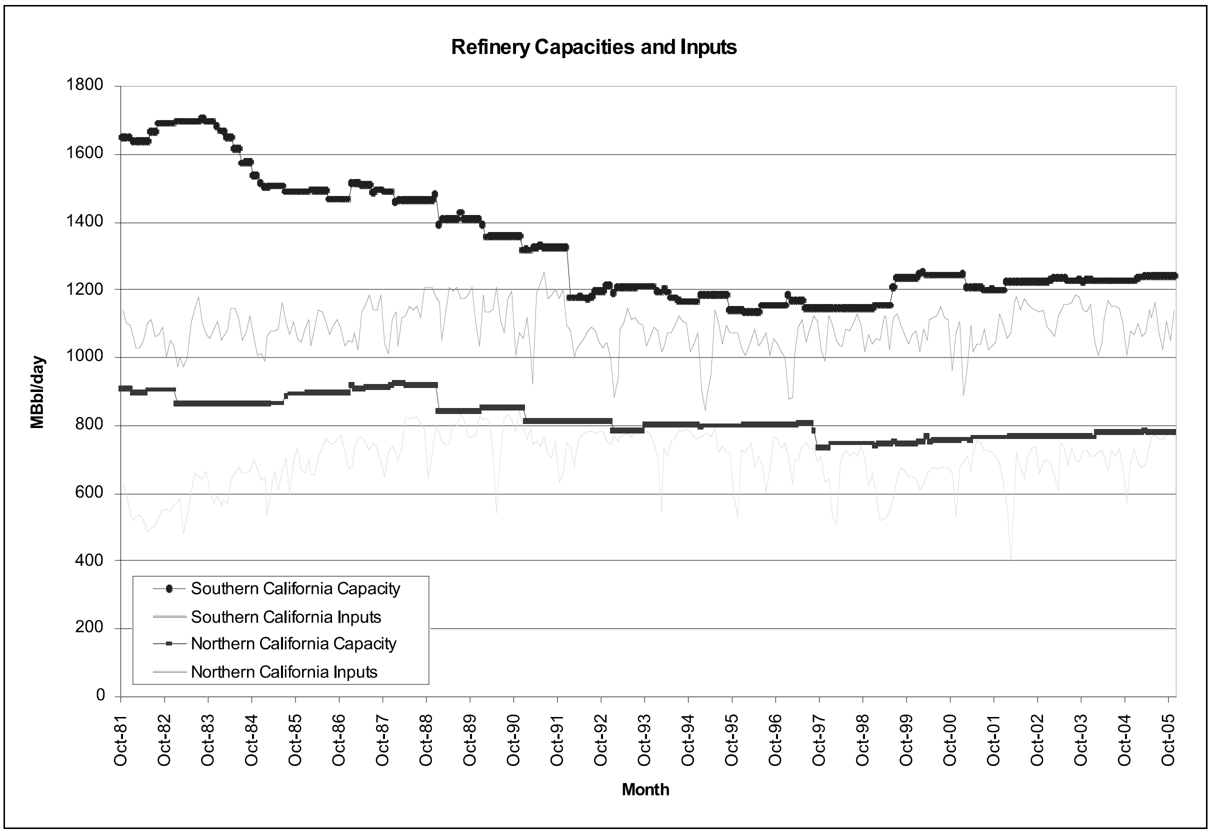
In California, 51 percent of the crude oil produced in the state is heavy crude. The transport of heavy crude through pipelines is complicated by the viscosity and inertia of the oil. Thus, some of the crude oil pipeline systems throughout the state require external heating. Booster stations are placed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

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

Refinery Operations

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

Figure 6



Source: Petroleum Industry Information Reporting Act

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

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

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

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

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

Findings

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

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

Current and Future Work

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

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

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

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

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

Endnotes

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

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View History: Monthly Annual

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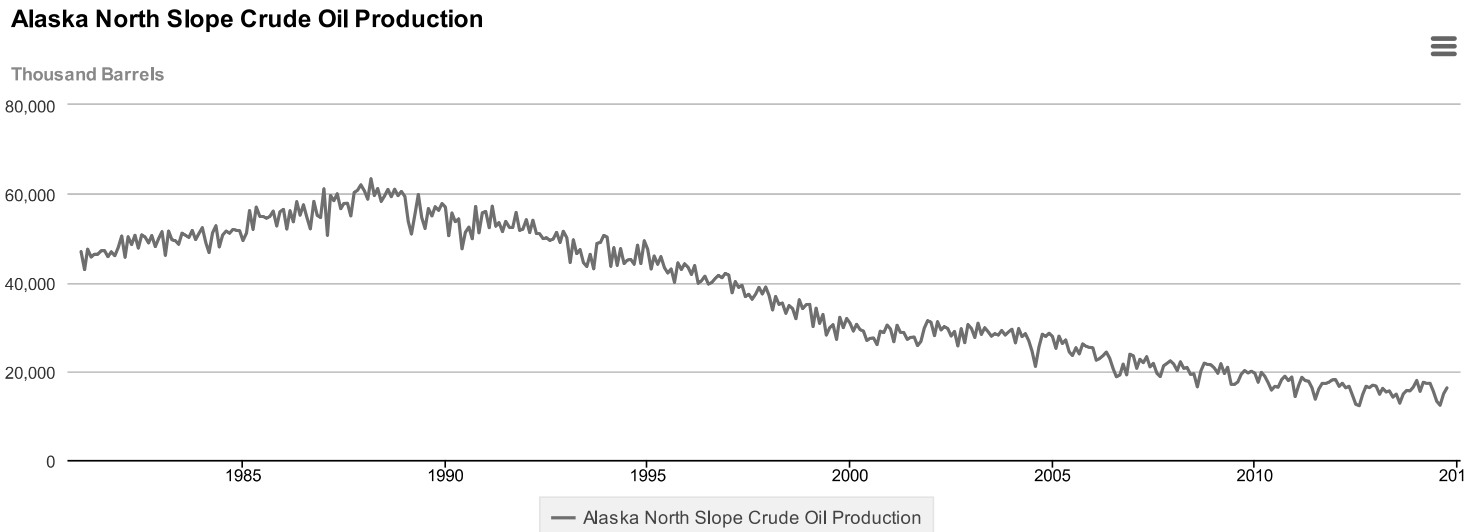

Source: U.S. Energy Information Administration

Chart Tools

no analysis applied

Alaska North Slope Crude Oil Production (Thousand Barrels)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1981	46,909	42,829	47,507	45,677	46,344	46,325	47,107	47,117	45,759	46,890	45,987	47,814
1982	50,450	45,656	50,262	48,518	50,621	47,707	50,695	50,247	48,876	50,565	48,033	49,876
1983	51,426	46,070	51,549	49,572	49,401	48,586	51,107	50,600	50,111	51,695	49,609	51,032
1984	52,340	48,897	46,683	51,158	52,743	47,978	50,665	51,559	51,070	51,934	51,750	51,641
1985	49,406	51,106	56,184	51,934	56,992	54,902	54,845	54,441	54,841	56,065	52,675	55,896
1986	56,471	52,015	56,132	53,605	58,207	55,142	57,471	54,691	52,038	58,277	55,087	54,600
1987	61,091	50,595	59,614	58,389	59,979	56,565	57,801	57,833	54,952	60,249	60,745	61,994
1988	60,633	58,761	63,361	59,575	61,149	58,234	59,434	60,962	59,277	61,028	59,520	60,513
1989	59,347	53,739	50,889	55,404	59,820	54,621	52,138	56,657	54,971	57,044	56,218	57,764
1990	56,989	50,473	55,643	53,676	54,322	47,542	51,289	52,469	49,810	57,126	51,135	55,691
1991	56,005	52,282	57,199	52,645	53,488	51,425	53,753	52,389	52,363	55,794	51,699	51,965
1992	54,135	51,191	54,010	50,976	50,940	49,843	50,049	49,424	49,775	51,271	48,967	51,537
1993	50,045	44,480	49,583	46,430	47,391	44,444	43,549	46,356	43,037	48,773	48,978	50,580
1994	50,186	43,605	47,808	43,830	47,584	44,214	45,016	45,136	44,059	48,382	44,227	49,360
1995	47,502	42,995	45,945	44,066	45,802	43,295	42,084	43,005	40,005	44,382	42,879	44,178
1996	43,387	41,763	43,792	39,786	40,311	41,380	39,578	39,958	40,879	41,579	40,985	42,018
1997	41,667	37,664	40,159	38,882	39,363	36,796	37,363	36,194	37,347	38,893	37,392	38,995
1998	37,078	33,776	36,861	35,059	35,372	33,040	34,804	34,109	31,815	36,099	34,068	34,969
1999	35,104	30,042	34,206	30,760	32,790	28,135	29,793	30,453	27,154	32,180	29,787	31,878
2000	30,816	29,021	30,571	29,348	29,025	26,890	27,412	27,461	25,946	29,026	28,682	30,407
2001	29,515	26,608	30,375	28,750	28,717	27,158	27,632	27,691	25,740	26,682	29,668	31,378
2002	31,050	27,969	31,147	29,275	30,056	29,596	27,895	28,962	25,678	29,561	26,384	30,506
2003	29,595	27,588	30,817	28,273	29,795	28,880	27,872	28,455	28,119	29,189	28,142	28,840

2004	29,470	26,357	29,596	27,780	28,448	26,877	24,455	21,042	25,452	28,351	27,811	28,576
2005	27,852	25,124	27,922	26,216	27,053	24,333	23,524	25,295	23,858	26,126	25,618	25,355
2006	25,226	22,476	22,781	23,478	24,320	22,911	20,576	18,720	19,151	21,615	19,154	23,837
2007	23,441	20,639	22,667	21,878	23,251	20,966	21,734	19,508	18,735	21,201	21,755	22,333
2008	21,605	20,114	22,112	20,628	20,802	19,244	19,396	16,460	20,038	21,813	21,488	21,404
2009	20,687	19,498	21,654	19,445	20,895	17,015	16,988	17,561	19,301	20,110	19,596	19,991
2010	19,537	17,496	19,707	18,858	17,415	15,727	16,563	16,359	18,116	18,855	17,836	18,668
2011	14,242	16,820	18,617	17,863	17,734	16,275	13,677	15,978	17,227	17,203	17,485	18,018
2012	18,051	16,554	17,290	16,230	16,597	14,483	12,524	12,198	14,710	16,597	16,258	16,841
2013	16,628	14,796	16,131	15,289	15,546	14,143	14,814	12,767	14,840	15,622	15,549	16,364
2014	17,878	15,439	17,482	17,220	17,265	15,441	13,181	12,290	14,886	16,217		

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 12/30/2014
Next Release Date: Last Week of January 2015

Referring Pages:

- Crude Oil Production

crudemonitor.ca

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Access Western Blend (AWB)

What is Access Western Blend crude?

Access Western Blend (AWB) is a heavy, high TAN dilbit produced by Devon Energy Canada and MEG Energy Corp. Production is from the Athabasca region south of Fort McMurray, Alberta. Production is generated by SAGD thermal methods. Diluent is supplied to the production sites from Edmonton and dilbit is pumped back to Edmonton on the Access Pipeline. AWB is available for upgrading in the Edmonton area, and for export on the Enbridge and Kinder Morgan systems.

Most Recent Sample Comments: AWB-931, Oct 1, 2014

Last 6 Samples

Other than marginally reduced BTEX, the October sample of Access Western Blend was consitent with historical trends. Typical simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	927.8	925.6	922.7	923.5
Gravity *(^{o}API)*	20.9	21.3	21.7	21.6
Sulphur *(wt%)*	4.03	3.96	3.95	3.94
MCR *(wt%)*	11.10	10.82	10.73	10.69
Sediment *(ppmw)*	129	106	104	139
TAN *(mgKOH/g)*	1.66	1.70	1.68	1.69
Salt *(ptb)*	5.7	4.8	4.1	6.0
Nickel *(mg/L)*	72.0	73.7	73.1	73.0
Vanadium *(mg/L)*	187.0	187.4	187.5	193.1
Olefins *(wt%)*	-	-	-	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3) ▼

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.05	0.05	0.05	0.04
Butanes	0.75	0.68	0.68	0.69
Pentanes	10.27	10.18	10.30	8.74
Hexanes	6.04	6.49	6.68	6.73
Heptanes	3.78	3.84	3.95	4.24
Octanes	2.21	2.10	2.11	2.45
Nonanes	1.12	1.02	0.98	1.17
Decanes	0.43	0.46	0.44	0.51

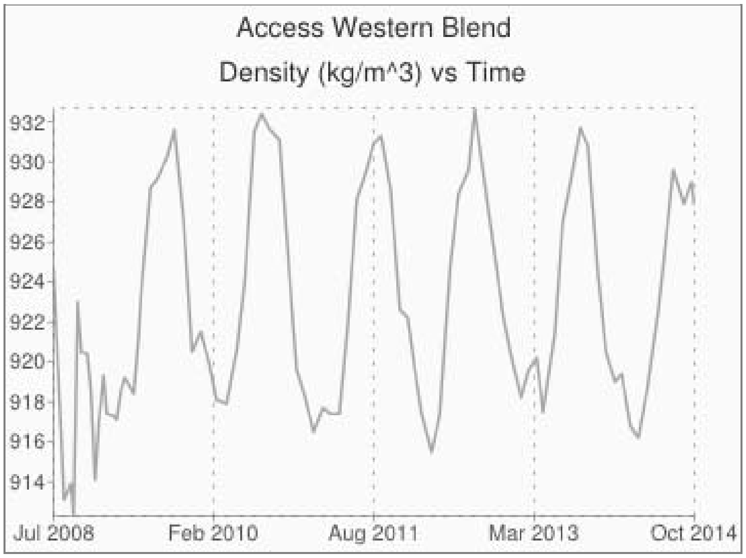
BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.17	0.24	0.25	0.29
Toluene	0.30	0.39	0.41	0.49
Ethyl Benzene	0.03	0.04	0.04	0.05
Xylenes	0.21	0.28	0.29	0.38

Distillation

TBP	ASTM D2892 & D5236	Select an assay date... ▼
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Access Western Blend Data



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PHILLIPS 66

Investor Update
Third Quarter 2014

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This presentation contains certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created thereby. Words and phrases such as “is anticipated,” “is estimated,” “is expected,” “is planned,” “is scheduled,” “is targeted,” “believes,” “intends,” “objectives,” “projects,” “strategies” and similar expressions are used to identify such forward-looking statements. However, the absence of these words does not mean that a statement is not forward-looking. Forward-looking statements relating to Phillips 66’s operations (including joint venture operations) are based on management’s expectations, estimates and projections about the company, its interests and the energy industry in general on the date this presentation was prepared. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecast in such forward-looking statements. Factors that could cause actual results or events to differ materially from those described in the forward-looking statements include fluctuations in crude oil, NGL, and natural gas prices, and refining and petrochemical margins; unexpected changes in costs for constructing, modifying or operating our facilities; unexpected difficulties in manufacturing, refining or transporting our products; lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, NGL, and refined products; potential liability from litigation or for remedial actions, including removal and reclamation obligations, under environmental regulations; limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets; and other economic, business, competitive and/or regulatory factors affecting Phillips 66’s businesses generally as set forth in our filings with the Securities and Exchange Commission. Phillips 66 is under no obligation (and expressly disclaims any such obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

This presentation includes non-GAAP financial measures. You can find the reconciliations to comparable GAAP financial measures at the end of the presentation materials or in the “Investors” section of our website.

Corporate Strategy

Operating excellence

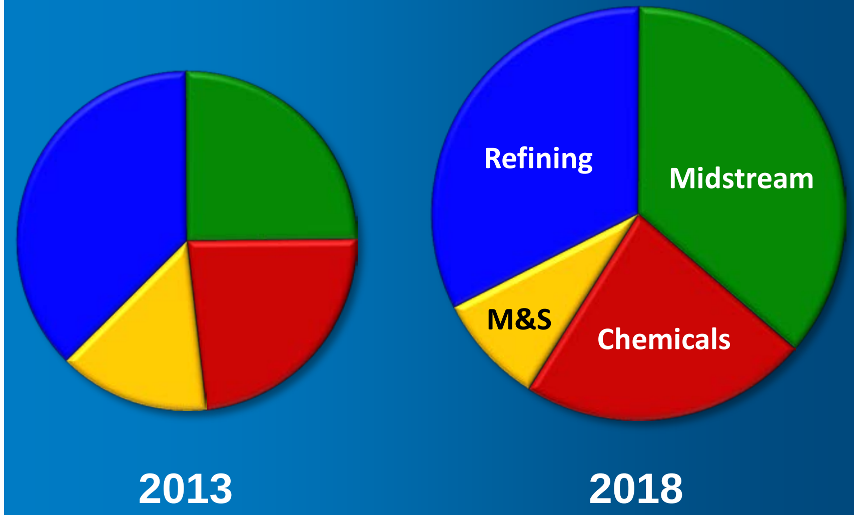
Growth

Returns

Distributions

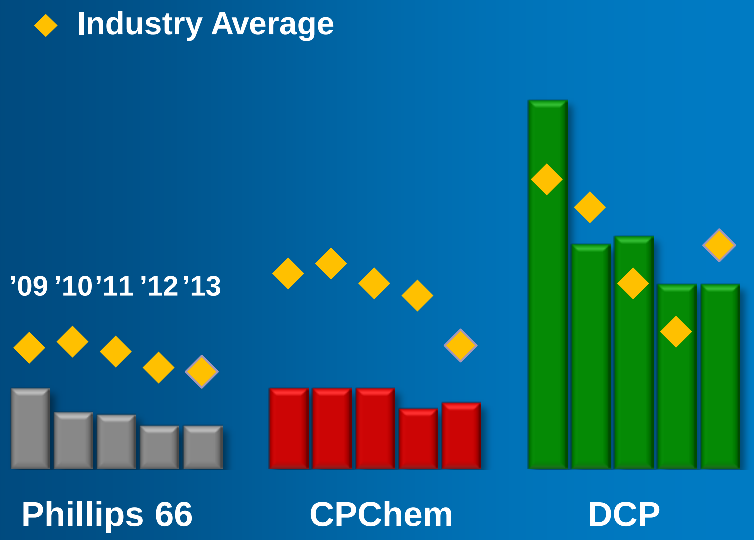
High-performing organization

Enterprise Value

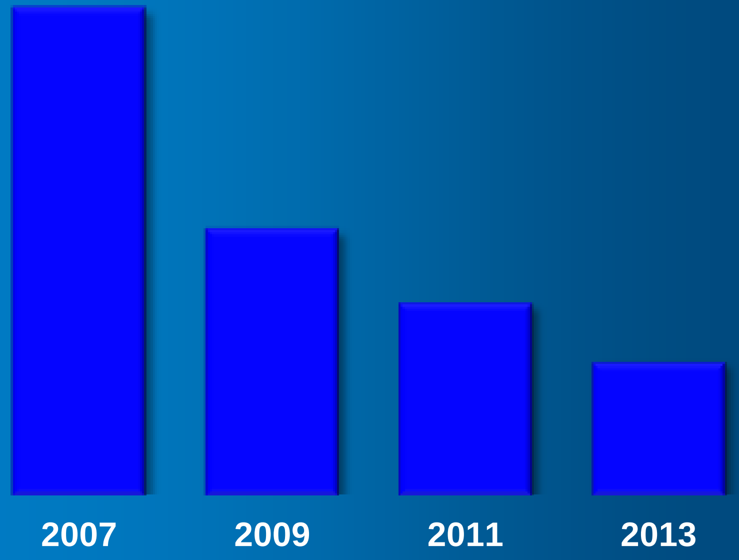


Operating Excellence

Total Recordable Rates
Incidents per 200,000 Hours Worked

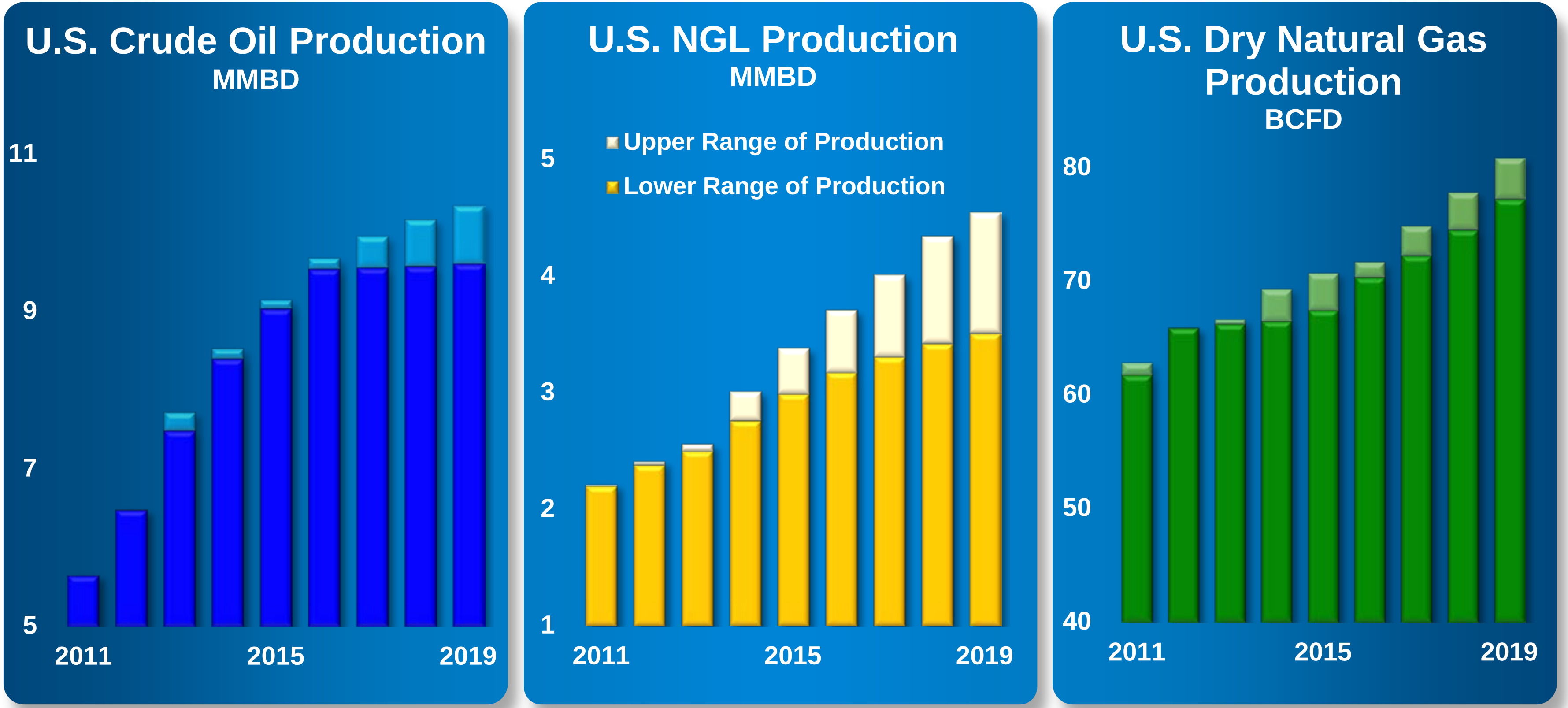


Refining Environmental Metrics



See appendix for footnotes.

U.S. Production Growth



Source: Industry consultants

Energy Landscape

North American oil and gas production growth

Energy infrastructure expansion

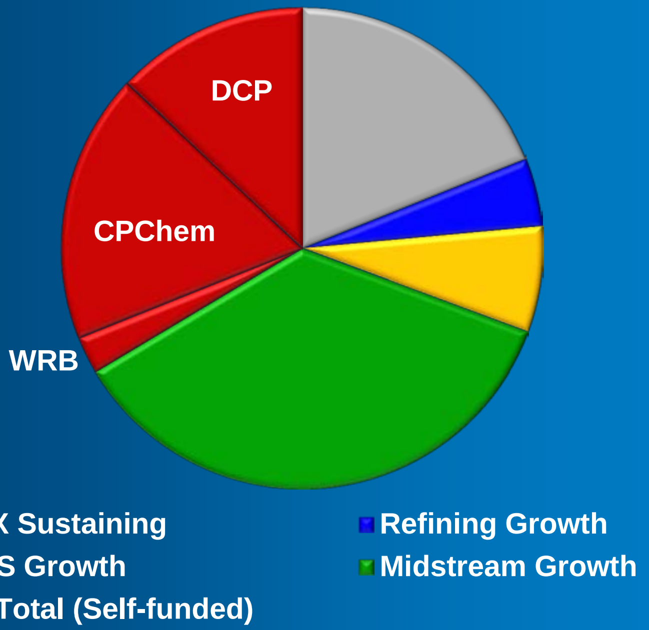
Global demand growth

Regulatory environment

Major project execution

Capital Program

2014E Total Capital Program
$5.8 B



$3.9 B 2014E Phillips 66 capital

- **$2.7 B 2014E initial Phillips 66 capital**
- **$1.2 B increase for Phillips 66 capital**
  - **$0.9 B acquisitions:**
    - Beaumont Terminal
    - Spectrum Corporation
    - Sweeny Cogen
    - Explorer Pipeline ownership increase
  - **$0.3 B organic growth acceleration:**
    - Sweeny Frac and LPG Export Terminal

$1.9 B 2014E JV capital (self-funded)

See appendix for footnotes.

Midstream

NGL

Pipelines and fractionation

Export terminals

Transportation

Crude and product pipelines

Terminals and storage

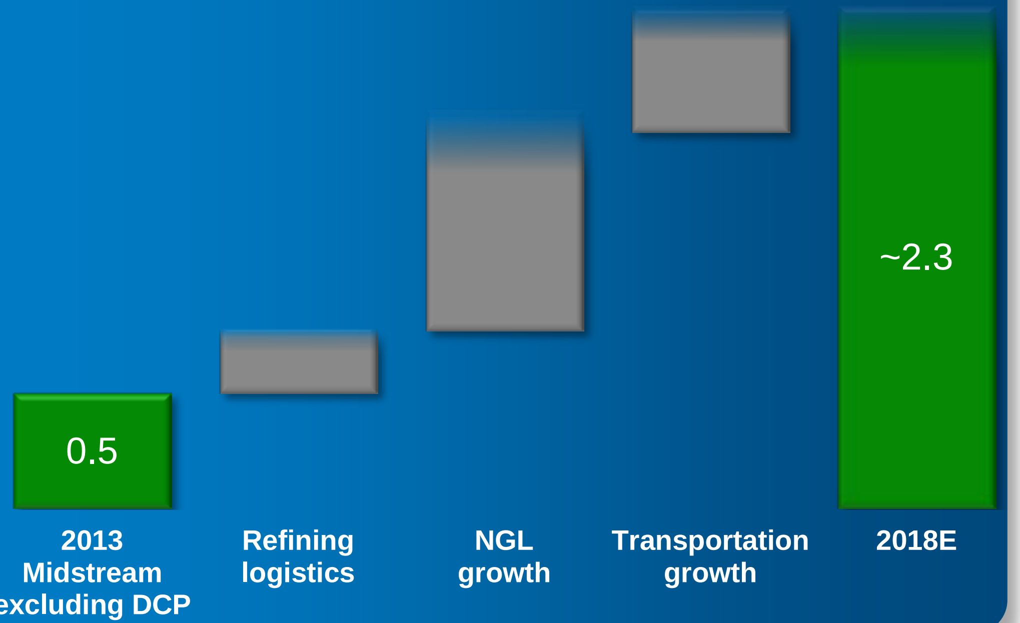
Rail, marine and trucks

DCP Midstream

Gathering and processing

Pipelines and fractionation

Midstream and Refining Logistics EBITDA
$B



See appendix for footnotes.

NGL – Gulf Coast

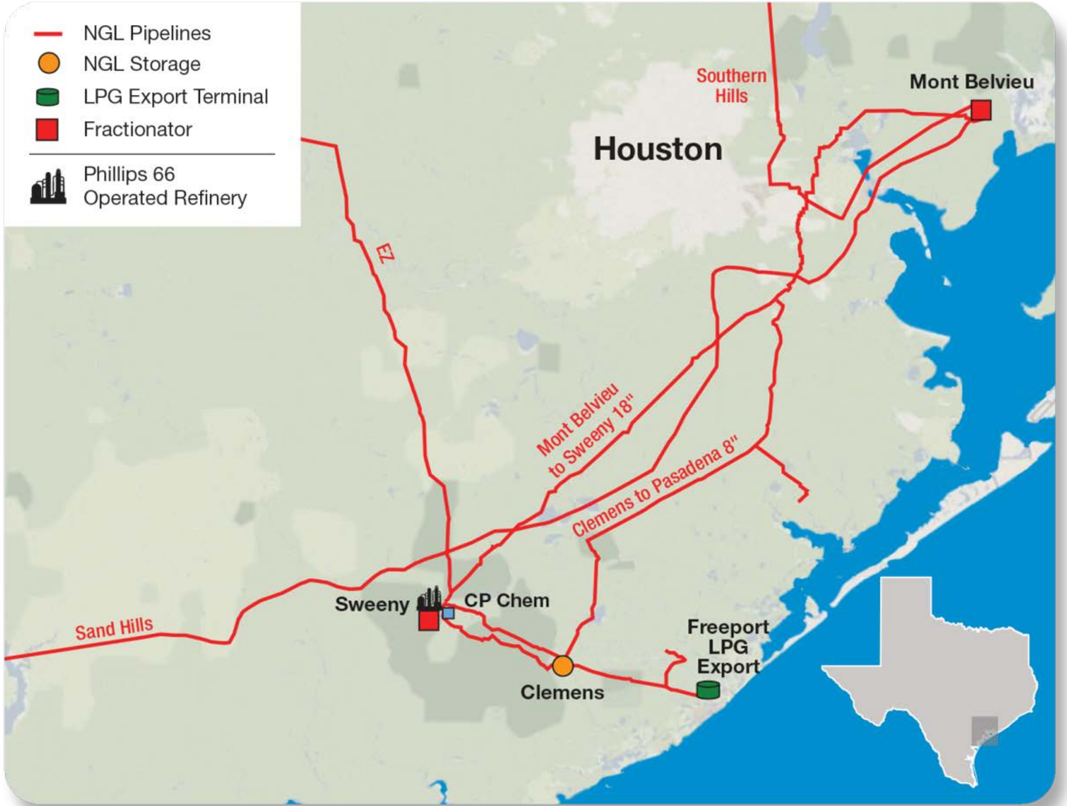
Sweeny Fractionator One – 100 MBD

Storage caverns – 8 MMBbls

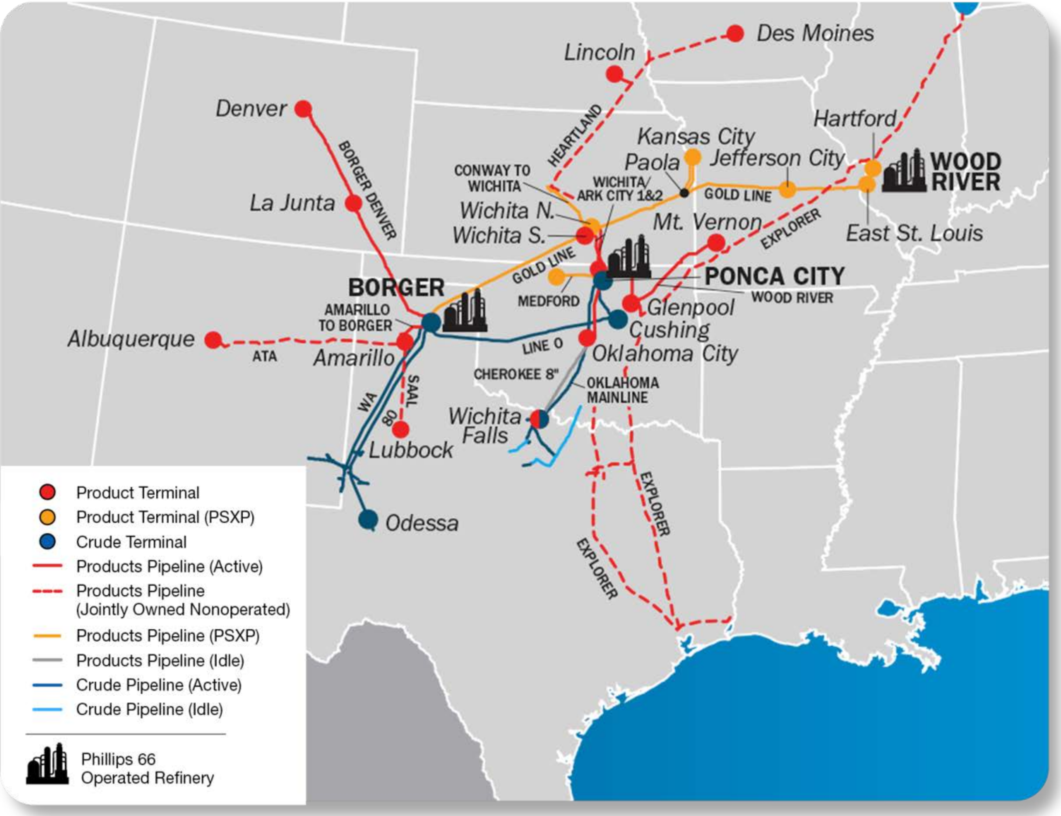
LPG export terminal – 150 MBD

Mont Belvieu pipeline – 200 MBD

Sweeny Fractionator Two – 110 MBD



Transportation – Midcontinent



3,600+ miles of pipeline

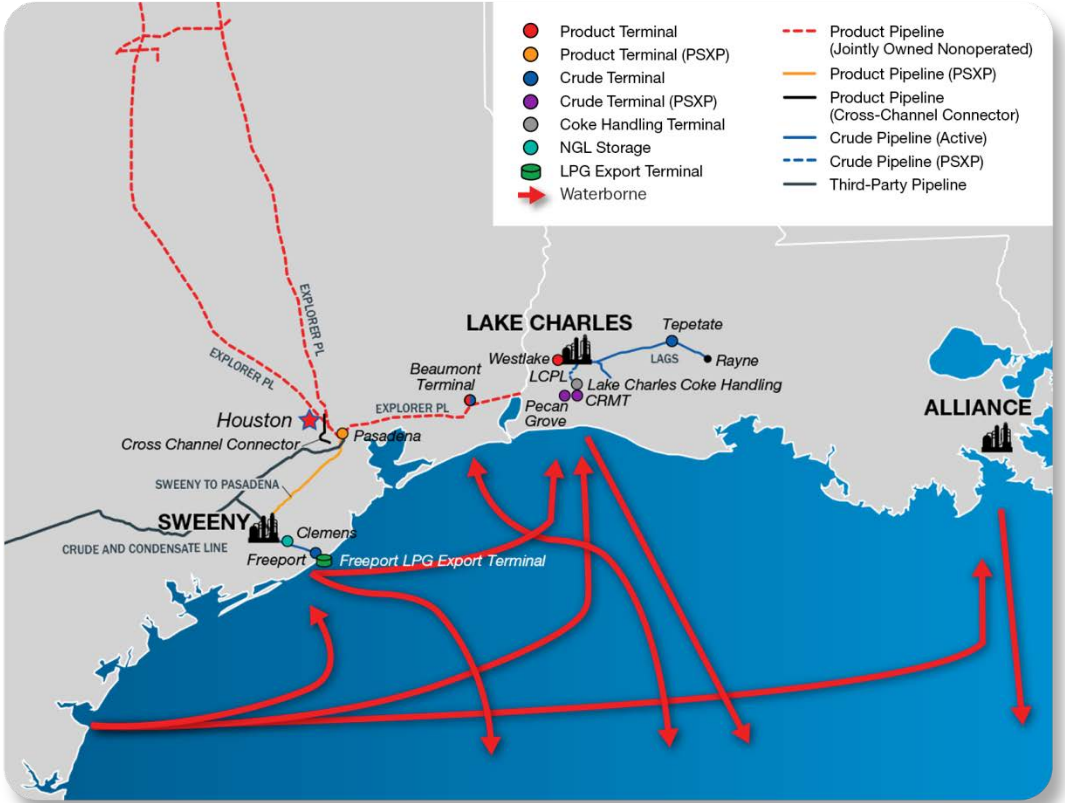
Over 20 crude and products terminals

Crude gathering infrastructure

Increased ownership in Explorer Pipeline

Transportation – West and East Coast

Transportation – Gulf Coast



Beaumont Terminal optionality

Integration with Refining

Access to Eagle Ford and Permian Basin

Increase export capability

Phillips 66 Partners

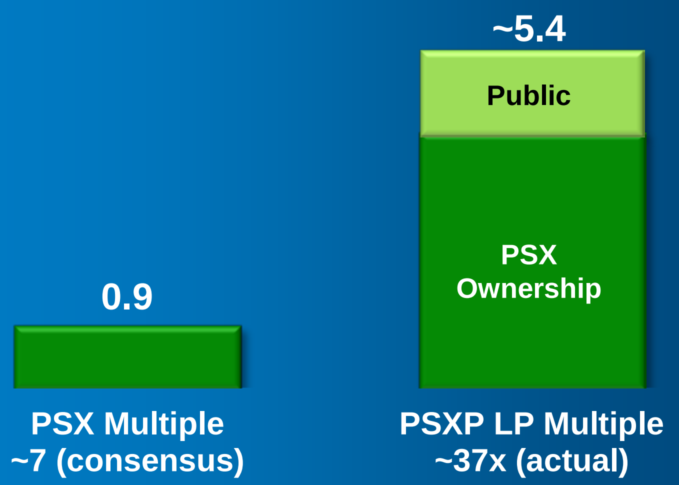
Increases PSX value

PSX sponsorship provides:

- Strong portfolio of existing assets
- Pipeline of organic growth

Low cost of capital

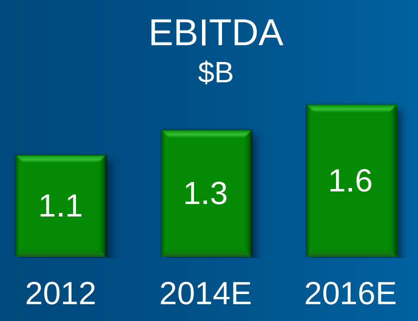
Enterprise Value
$B

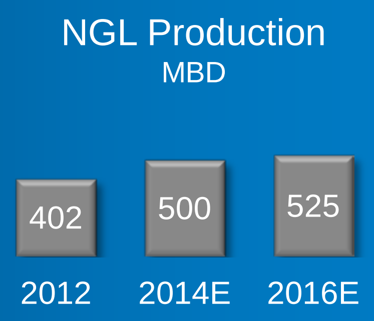


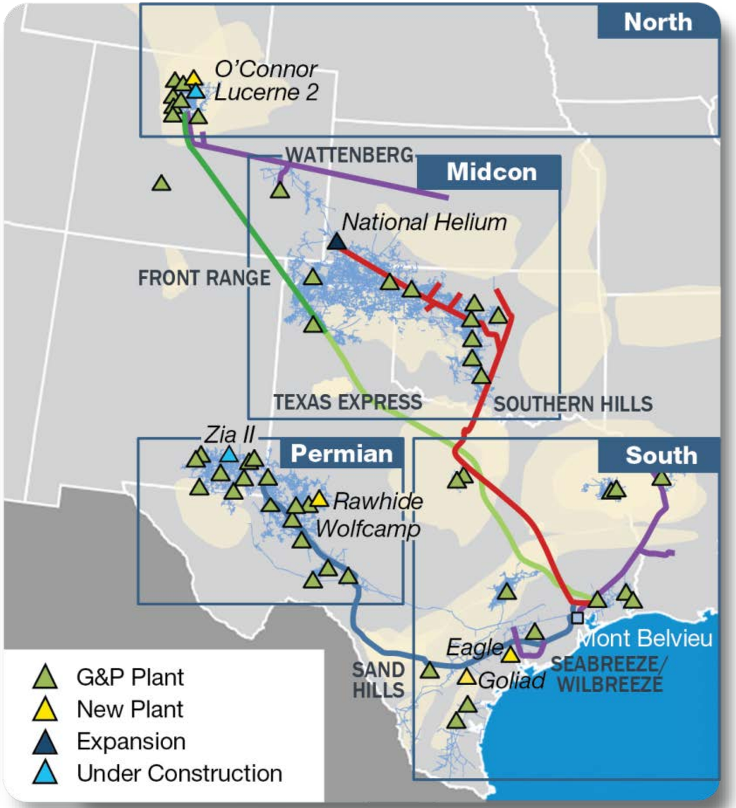
See appendix for footnotes.

DCP Midstream

	2013 NGL Production MBD	Processing Capacity BCFD	Capex 2014E-2016E $B
Permian	~130	1.4	1.0 - 1.5
South	~130	3.2	.50 - 1.0
North	~ 40	0.9	1.0 - 1.5
Midcon	~120	2.0	.75 - 1.0
Logistics	N/A	N/A	.75 - 1.0

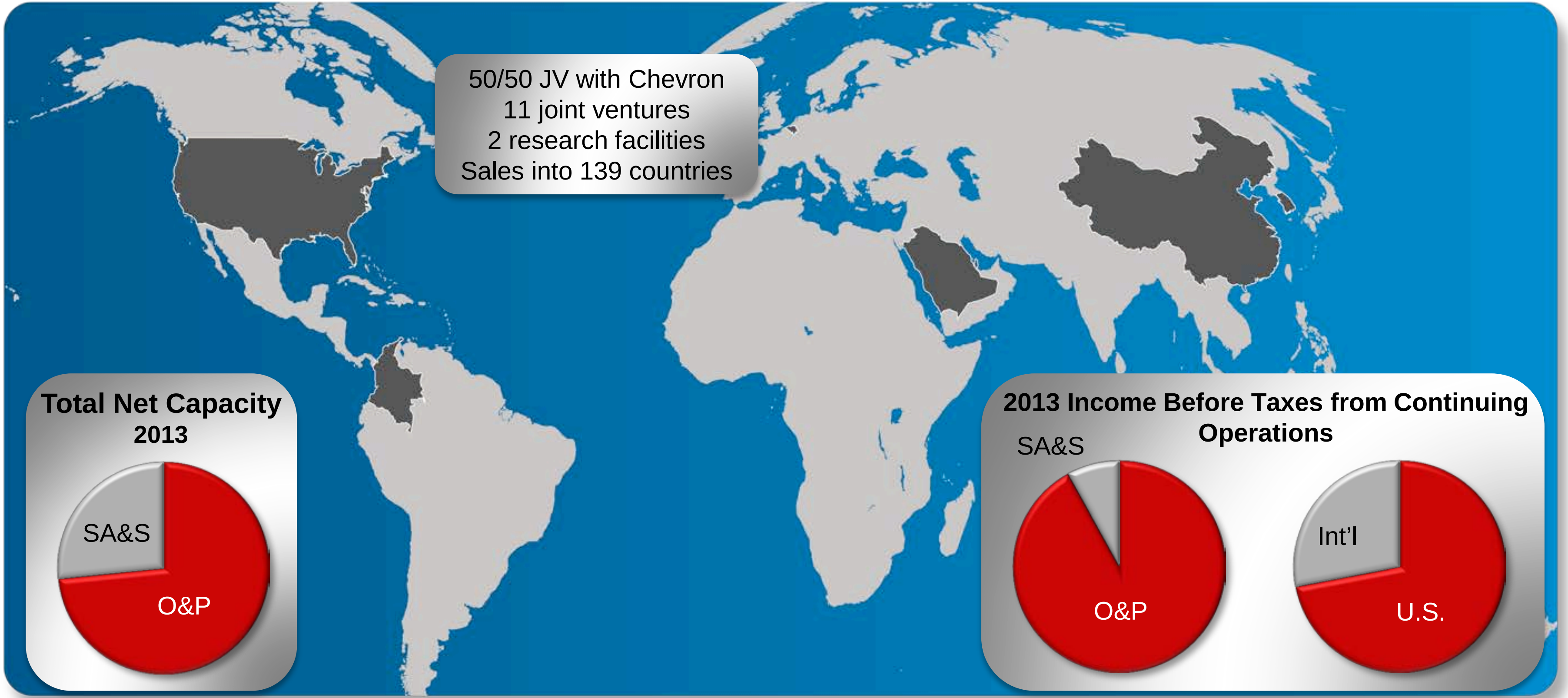






EBITDA chart reflects 100% DCP Midstream. See appendix for additional footnotes.

Chemicals – CPChem Portfolio



Chemicals – CPChem Growth Plans

2013	2014	2015	2016	2017

1-Hexene Unit
250 kMTA

Sweeny Ethylene
90 kMTA

USGC Petrochemicals
1,500 kMTA (ethylene)
1,000 kMTA (polyethylene)

NAO Expansion
~100 kMTA

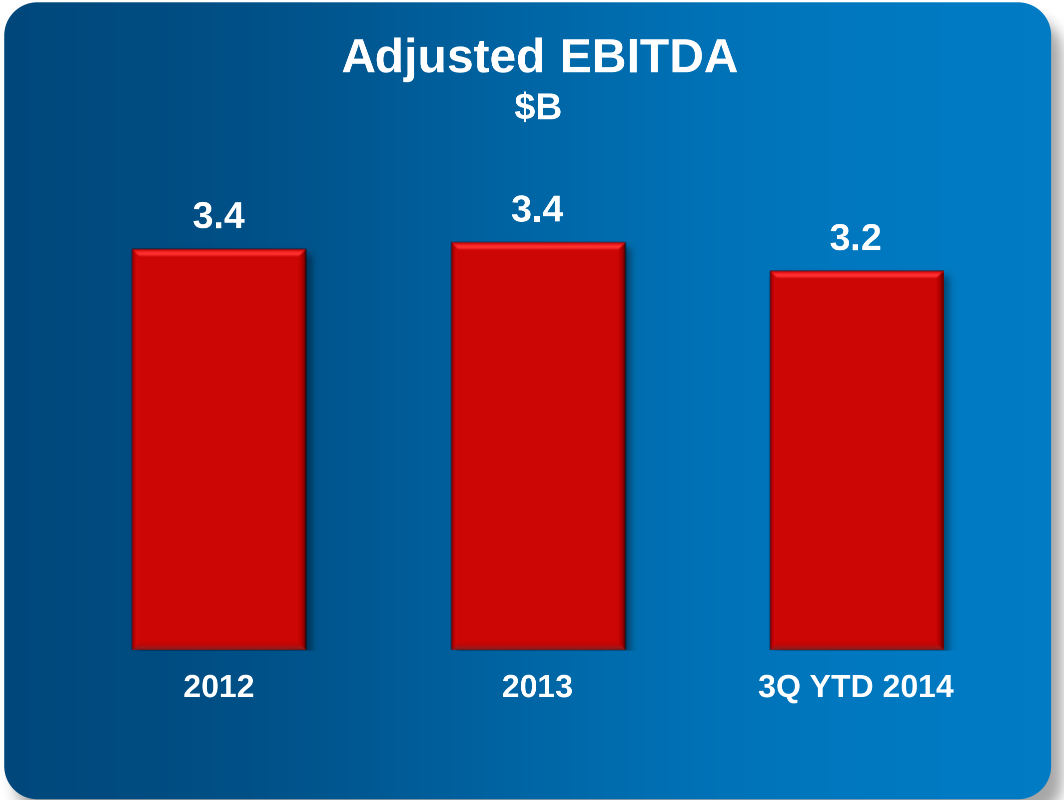
Self-funded capital program

$6.5 – 7 B growth spending

36% U.S. O&P capacity growth

Figures are 100% CPChem. See appendix for additional footnotes.

Chemicals – CPChem



Leading returns

Market leader

- Largest global HDPE producer
- 2nd largest global alpha olefins producer
- 4th largest N.A. ethylene producer

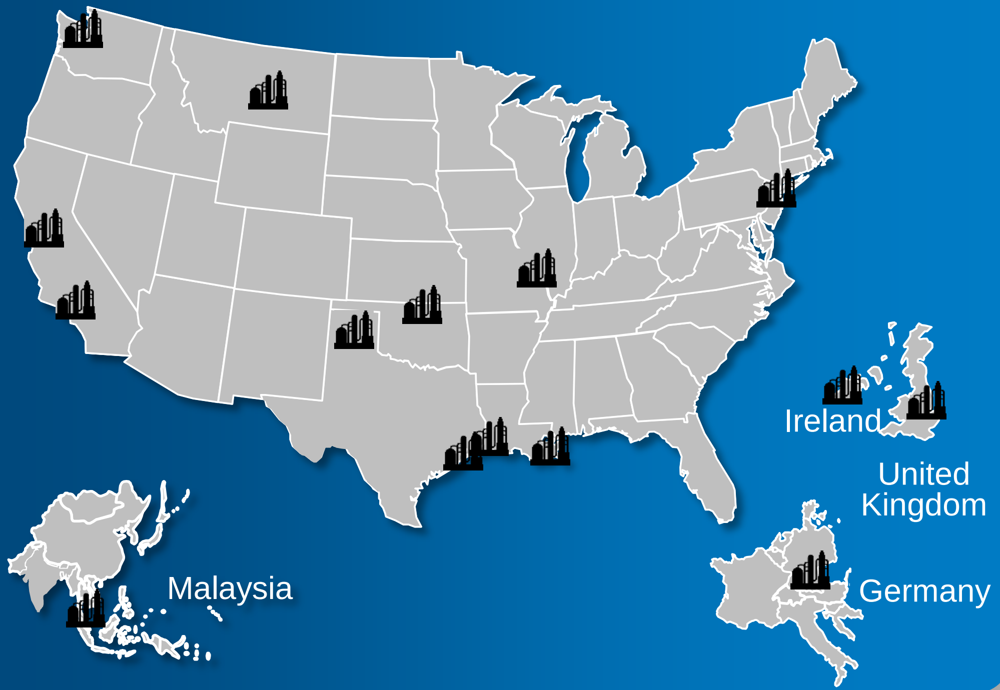
Estimated new project EBITDA

- $1.3 – 1.6 B/year 2017+

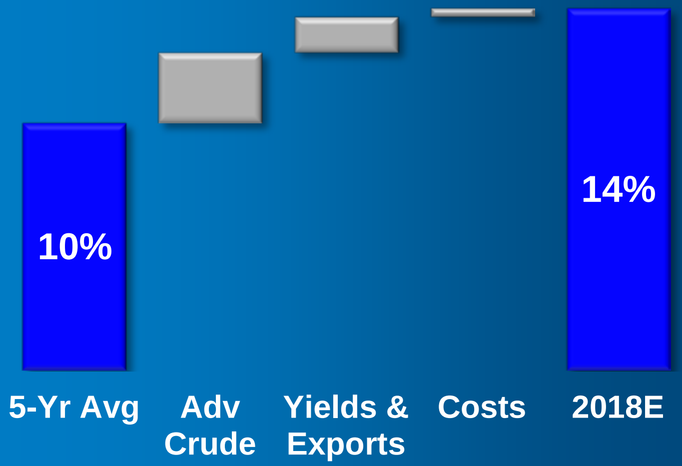
Figures reflect 100% CPChem.

Refining

15 refineries worldwide – 2.2 MMBD crude capacity



ROCE Improvement Constant Crack Spreads



See appendix for footnotes.

Marketing and Specialties

U.S. Marketing

- Ensures Refining pull-through

International Marketing

- Retail in Europe

Specialties

- Finished lubricants
- Base oil joint venture
- Needle and anode coke

Adjusted EBITDA
2009 – 2014 Q3 YTD

Disciplined Capital Allocation

Investment

Sustain operations

Fund capacity growth

Generate competitive returns

Distributions

Double-digit dividend growth rate

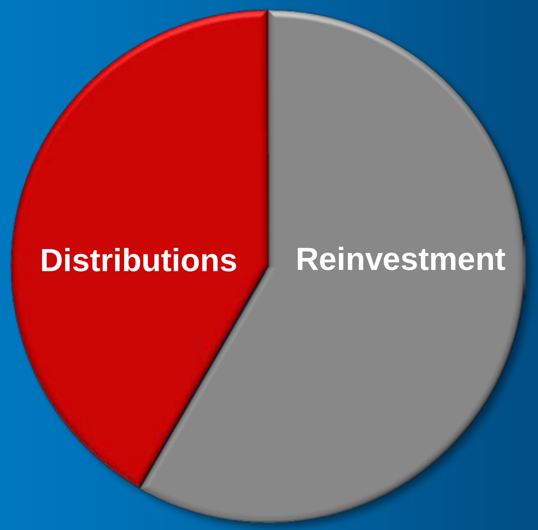
Repurchase shares

Capital Structure

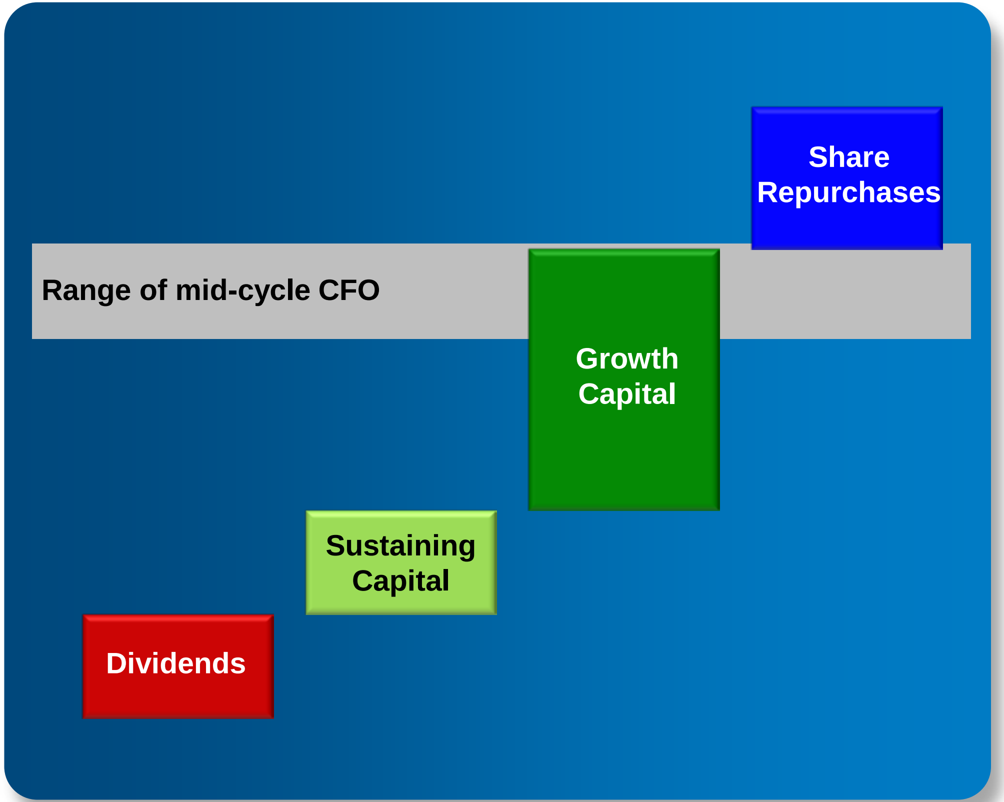
Maintain financial flexibility

Target debt-to-capital 20 – 30%

2014E – 2016E



Capacity to Execute

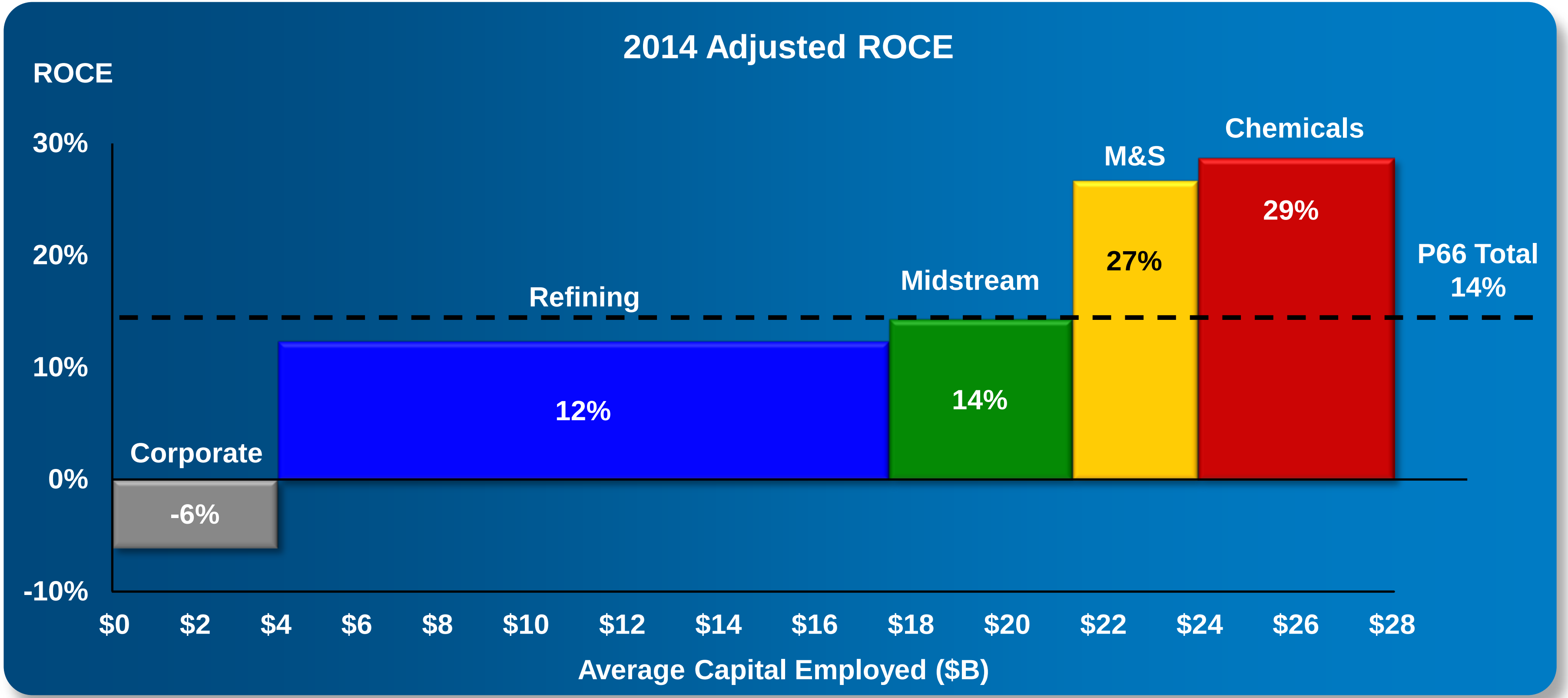


Additional Sources:

- Cash on hand
- Debt capacity
- MLP drop-downs
- Asset sales
- New project cash flows

See appendix for footnotes

Returns

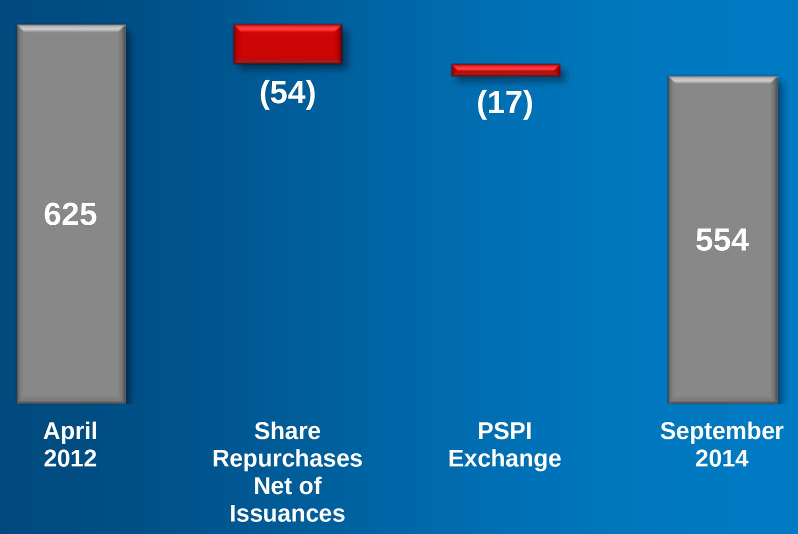


See appendix for footnotes.

Distributions

Phillips 66 Common Stock

MM shares



Dividend Growth

¢/share

150% growth vs. 69% peer average

See appendix for footnotes.

Delivering on Commitments

Growth

$4.2 B 2014E growth capital program

Beaumont Terminal and Spectrum acquisitions

Grow Phillips 66 Partners

Returns

95% advantaged crude slate in 3Q 2014

Record export volumes

Distributions

28% dividend increase

$2 B additional share repurchases

See appendix for footnotes.

Compelling Investment

Shareholder returns

Unique portfolio

EBITDA growth

Disciplined capital allocation

Multiple expansion

See appendix for footnotes.

Appendix

Institutional Investors Contact

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Footnotes

Slide 4

Injury statistics do not include major projects.

Industry Averages are from: Phillips 66 – American Fuel & Petrochemical Manufacturers (AFPM) refining data, CPChem – American Chemistry Council (ACC), DCP – Gas Processors Association (GPA).

Slide 7

“Sustaining” capital shown in chart includes Phillips 66 share only. Proportionate share of JV sustaining is included in the respective sections for DCP, CPChem and WRB, each of which is expected to be self-funding. 70% of capital program invested in growth based on 2014E – 2016E.

Slide 8

Refining logistics earnings are reported in Refining segment.

Slide 13

Phillips 66 ownership consists of ~75% of the total LP and GP units; Phillips 66 multiple of ~7x is based on consensus; Phillips 66 Partners multiple is based on actuals as of October 31, 2014.

Slide 14

EBITDA assumes commodity-neutral growth and includes noncontrolling interests.

Slide 16

Capital expenditures are estimates.

Slide 18

The 5-year average adjusted ROCE has been recast to reflect realignment of specific businesses moved from the Refining segment to the Marketing and Specialties segment.

Footnotes

Slide 21

Mid-cycle cash from operations is estimated based on a 10-year history normalized for Phillips 66's current operations and structure.

Slide 22

Data reflects 3Q 2014 YTD Annualized Adjusted Return on Capital Employed (ROCE).

Slide 23

Peer average includes DOW, MPC, TSO and VLO.

Slide 24

$4.2 B 2014E growth capital program includes proportionate share of JV growth capital.

Slide 25

Chart reflects total shareholder return May 1, 2012 to October 31, 2014. Phillips 66 dividends assumed to be reinvested in stock on payment date.

2014 Sensitivities

	Net Income $MM
Midstream	
1¢/Gal Increase in NGL price	4
10¢/MMBtu Increase in Natural Gas price	2
$1/BBL Increase in WTI price	2
Chemicals	
1¢/Lb Increase in Olefins Chain Margin (Ethylene, Polyethylene, NAO)	35
Worldwide Refining (assuming 94% refining utilization)	
$1/BBL Increase in Refining Margin	440
Impacts due to Actual Crude Feedstock Differing from Feedstock Assumed in Market Indicators:	
$1/BBL Widening LLS / Maya Differential (LLS less Maya)	50
$1/BBL Widening WTI / WCS Differential (WTI less WCS)	40
$1/BBL Widening WTI / WTS Differential (WTI less WTS)	15
$1/BBL Widening LLS / WCS Differential (LLS less WCS)	10
$1/BBL Widening ANS / WCS Differential (ANS less WCS)	10
$0.10/MMBtu Increase in Natural Gas price	(10)

Sensitivities shown above are independent and are only valid within a limited price range.

Capital Program

	Growth	Sustaining	Total
	Millions of Dollars		
	2014 Budget		
Capital Expenditures and Investments*			
Consolidated			
Midstream			
Transportation	806	150	956
NGL	1,262	5	1,267
	2,068	155	2,223
Chemicals	-	-	-
Refining	264	751	1,015
Marketing and Specialties	413	74	487
Corporate	15	116	131
	2,760	1,096	3,856
Selected Equity Affiliates			
DCP	600	150	750
CPChem	852	194	1,046
WRB	28	117	145
	1,480	461	1,941
Capital Program**			
Midstream			
Transportation	806	150	956
DCP	600	150	750
NGL	1,262	5	1,267
	2,668	305	2,973
Chemicals	852	194	1,046
Refining	292	868	1,160
Marketing and Specialties	413	74	487
Corporate	15	116	131
	4,240	1,557	5,797

**Includes non-cash capitalized leases and interest.*

***Includes Phillips 66's share of capital spending by DCP, CPChem and WRB, which are expected to be self-funded.*

Non-GAAP Reconciliations

	Millions of Dollars	
Year Ended December 31		2013
Transportation and NGL		
Net income attributable to Phillips 66	$	259
Plus:		
Net income attributable to noncontrolling interests		17
Income taxes		142
Depreciation and amortization		88
EBITDA*	$	506

**Includes noncontrolling interests.*

Refining logistics, NGL growth and Transportation growth forecasts were derived on an EBITDA-only basis. Accordingly, elements of net income including tax and depreciation information are not available. Together, these items generally result in a significant uplift in EBITDA over net income.

Non-GAAP Reconciliations

	Millions of Dollars	
	First Year	
Sweeny Fractionator One and Two, and Freeport Export Facility		
Estimated net income	$	370
Plus:		
Estimated income taxes		230
Estimated net interest expense		10
Estimated depreciation and amortization		190
Estimated EBITDA	$	800

Non-GAAP Reconciliations

	Millions of Dollars
Years Ended December 31	2014E
Phillips 66 Partners LP	
Net income	$ 119.0 - 124.0
Plus:	
Depreciation	15.0
Net interest expense	5.4
Amortization of deferred rentals	0.4
Provision for income taxes	0.4
EBITDA	$ 140.2 - 145.2

Non-GAAP Reconciliations

Years Ended December 31		Millions of Dollars 2012	2014E	2016E
100% DCP Midstream				
Net income attributable to members' interest	$	486	510	555
Plus:				
Net income attributable to noncontrolling interests		97	135	255
Income taxes		2	10	10
Net interest expense		193	315	345
Depreciation and amortization		291	360	430
EBITDA*	$	1,069	1,330	1,595

**Includes noncontrolling interests.*

Non-GAAP Reconciliations

		Millions of Dollars		
		2012	2013	3Q YTD 2014
100% CPChem				
Net income	$	2,403	2,743	2,492
Plus:				
Income taxes		67	71	71
Net interest expense		8	(3)	(2)
Depreciation and amortization		356	278	212
EBITDA	$	2,834	3,089	2,773
Adjustments (pre-tax):				
Proportional share of equity affiliates income taxes		91	115	109
Proportional share of equity affiliates net interest expense		17	24	14
Proportional share of equity affiliates depreciation and amortization		157	214	163
Premium on early debt retirement		287	-	-
Impairments		-	-	175
Adjusted EBITDA	$	3,386	3,442	3,234

Non-GAAP Reconciliations

		Millions of Dollars	
		Low	High
100% CPChem Incremental Project Earnings Projections			
Estimated incremental net income	$	1,000	1,313
Plus:			
Estimated income taxes		20	27
Estimated net interest expense		-	-
Estimated depreciation		280	260
Estimated EBITDA	$	1,300	1,600

Non-GAAP Reconciliations

		Millions of Dollars
		Average 2009 - 2013
Refining - ROCE		
Numerator		
Average 2009 - 2013 net income	$	998
After-tax interest expense		-
GAAP ROCE earnings		998
Special Items		452
Adjusted ROCE earnings	$	1,450
Denominator		
GAAP average capital employed*	$	13,940
Adjusted ROCE *(percent)*		10%
GAAP ROCE *(percent)*		7%

**2013 average total equity plus debt.*

Non-GAAP Reconciliations

	Millions of Dollars		
	January 1, 2009 - September 30, 2014		
	U.S. Marketing	International Marketing	Specialties
Net income	$ 1,518	1,226	1,249
Plus:			
Provision for income taxes	954	590	750
Net interest expense	(119)	-	3
Depreciation and amortization	149	548	45
EBITDA	$ 2,502	2,364	2,047
Adjustments (pretax):			
Gain on asset dispositions	(260)	(106)	(83)
Pending claims and settlements	(19)	-	-
Impairments	71	-	-
Exit of a business line	-	-	54
Tax law impacts	(6)	-	-
Adjusted EBITDA	$ 2,288	2,258	2,018

Non-GAAP Reconciliations

	Millions of Dollars						
	Nine Months Ended September 30, 2014						
		Phillips 66	Midstream	Chemicals	Refining	Marketing & Specialties	Corporate
ROCE							
Numerator							
Net Income	$	3,639	435	870	1,254	667	(293)
After-tax interest expense		126	-	-	-	-	126
GAAP ROCE earnings		3,765	435	870	1,254	667	(167)
Special Items		(746)	-	69	-	(109)	-
Adjusted ROCE earnings	$	3,019	435	939	1,254	558	(167)
Denominator							
GAAP average capital employed*	$	28,477	4,052	4,358	13,520	2,788	3,663
Discontinued Operations		(96)	-	-	-	-	-
Adjusted average capital employed*	$	28,381	4,052	4,358	13,520	2,788	3,663
Annualized Adjusted ROCE *(percent)*		14%	14%	29%	12%	27%	-6%
Annualized GAAP ROCE *(percent)*		18%	14%	27%	12%	32%	-6%

**Total equity plus debt.*

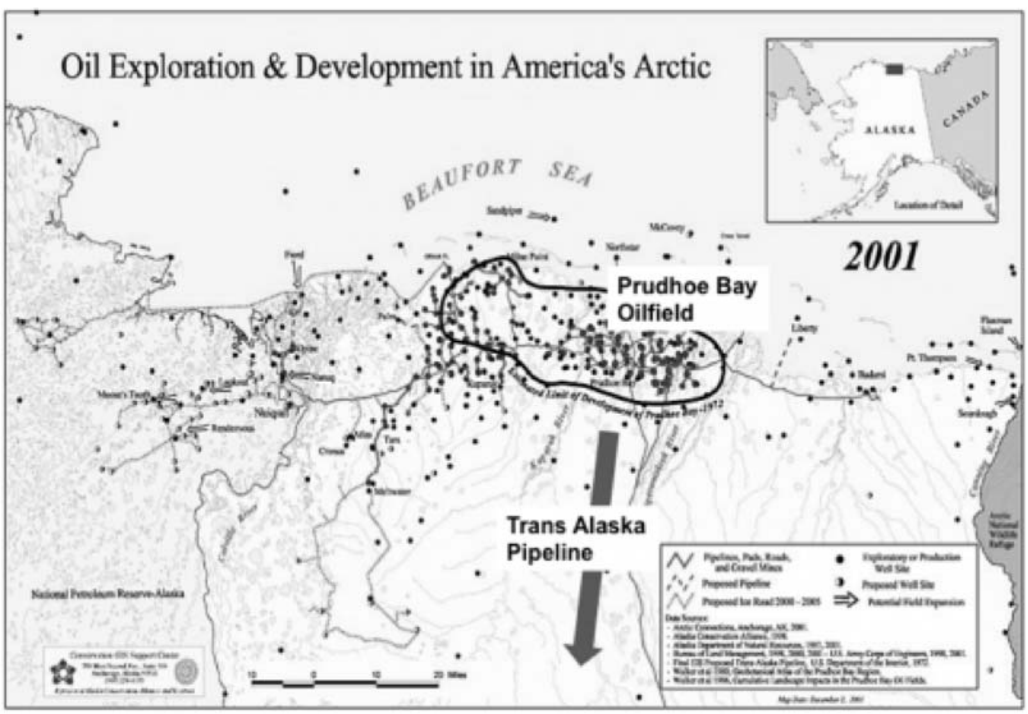
RBN Energy LLC

After the Oil Rush – ANS Decline and the West Coast Crude Market

Wednesday, 01/02/2013Published by: Sandy Fielden

Alaska North Slope (ANS) crude production has been in decline since 1987. Once producing over 2 MMb/d this prolific field averaged just 520 Mb/d in 2012. At the same time refiners on the West Coast who previously relied on ANS are beginning to get access to domestic shale crude and might be consuming Canadian crude exports from British Columbia in a few years' time. Today we explain the impact on West Coast crude pricing.

Alaska North Slope (ANS) crude is produced from the Prudhoe Bay field on the northern coast of Alaska beside the Beaufort Sea (see map below). The field was discovered in 1968 by ARCO (Atlantic Richfield now part of BP) and Humble Oil and Refining Company (now part of ExxonMobil). Production started in 1977 after the Mid-East Oil Crisis raised crude prices enough to justify construction of an $8B pipeline from Prudhoe Bay to Valdez marine terminal.



(http://www.rbnenergy.com/sites/default/files/styles/colorbox-full-screen/public/field/image/map_2.png)

(Click to Enlarge)

ANS is considered medium sour crude with an API gravity of 31.5 and 0.96 percent sulfur content. The chart below shows Alaskan crude production since 1977. After rising to a peak of over 2 MMb/d in 1987 production has been in decline since then. Average daily production through October of 2012 according to the Energy Information Administration (EIA) was 520 Mb/d. The largest ANS producers are ExxonMobil, ConocoPhillips and BP. There are still large recoverable crude reserves in Alaska but they will require significant investment to exploit and transport to market. Changes in the US crude supply position have made that new investment in Alaska less economically attractive. Prudhoe Bay also produces significant quantities of natural gas (8 Bcf/d). The majority of this gas is re-injected to improve oil recovery. There has been considerable debate and planning about building a pipeline to bring natural gas from Alaska to the US but low gas prices in the US make such a proposal uneconomic at present. For now ANS hydrocarbon production looks set to continue to decline.

Phillips 66
2014 Fact Book

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BUILDING
GROWING

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An electronic file of this Fact Book can be obtained by visiting *www.phillips66.com,* selecting the Investors tab and then Financial & Operating Information. The file is located in the Annual Reports section of that page.

COVER: Sweeny Refinery in Old Ocean, Texas.

Phillips 66 is investing, building and growing in order to capitalize on the opportunities of the American energy revolution.

Billings Refinery, Billings, Montana.

COMPANY OVERVIEW

Built on more than 130 years of experience, Phillips 66 is a growing energy manufacturing and logistics company with high-performing Midstream, Chemicals, Refining, and Marketing and Specialties businesses. This integrated portfolio enables Phillips 66 to capture opportunities in the changing energy landscape. Headquartered in Houston, the company has 13,500 employees who are committed to operating excellence and safety. Phillips 66 had $50 billion of assets as of Dec. 31, 2013. Phillips 66 stock trades on the New York Stock Exchange under the ticker symbol PSX.

Midstream

Our Midstream segment transports crude oil, refined products, natural gas and natural gas liquids (NGL). It also gathers, processes and markets natural gas and NGL to power businesses, heat homes and provide feedstock to the petrochemical industry. The segment consists of Phillips 66's NGL business; Phillips 66's Transportation business, including Phillips 66 Partners LP, our master limited partnership (MLP) formed in 2013; and DCP Midstream, LLC, our 50-50 joint venture with Spectra Energy Corp.

Refining

Our Refining segment transforms crude oil into petroleum products such as gasoline, diesel and aviation fuel. Phillips 66 is one of the largest refiners in the United States and worldwide, with 15 refineries and a net crude oil processing capacity of 2.2 million barrels per day (MMBD).

Chemicals

Chevron Phillips Chemical Company LLC (CPChem), our 50-50 joint venture with Chevron, manufactures and markets petrochemicals, polymers and plastics found in cars, electronics and other everyday goods. CPChem is North America's largest producer of high-density polyethylene and the fourth-largest North American ethylene producer. CPChem has a large global presence with 35 manufacturing sites and 33 billion pounds (BLb) of net annual processing capacity.

Marketing and Specialties

The Marketing and Specialties segment includes our global fuel marketing and lubricants businesses. Phillips 66's U.S. Marketing business markets fuels under the brands Phillips 66®, Conoco® and 76®. In Europe, we sell primarily under the JET® brand in the United Kingdom, Austria and Germany, and the Coop® brand in Switzerland. The company also markets lubricants in 65 countries, and has several other specialty businesses, including base oil, petroleum coke, waxes, solvents and polypropylene.

2013 ACCOMPLISHMENTS

- Continued to be a top performer in safety compared to peers and integrated majors.
- Returned more than $3 billion of capital to our shareholders.
- Successfully launched Phillips 66 Partners, an MLP, to own, develop and acquire primarily fee-based transportation and midstream assets.
- Increased our quarterly dividend by 25 percent on two separate occasions.
- Achieved a total shareholder return of 48 percent.
- Repaid $1 billion of debt, reducing our total debt to about $6 billion and our debt-to-capital ratio to 22 percent.
- Invested $2 billion in growth capital.

2014 KEY INITIATIVES

Growth

- Advance midstream infrastructure projects.
- Progress CPChem's U.S. Gulf Coast (USGC) Petrochemicals Project.
- Grow Phillips 66 Partners.

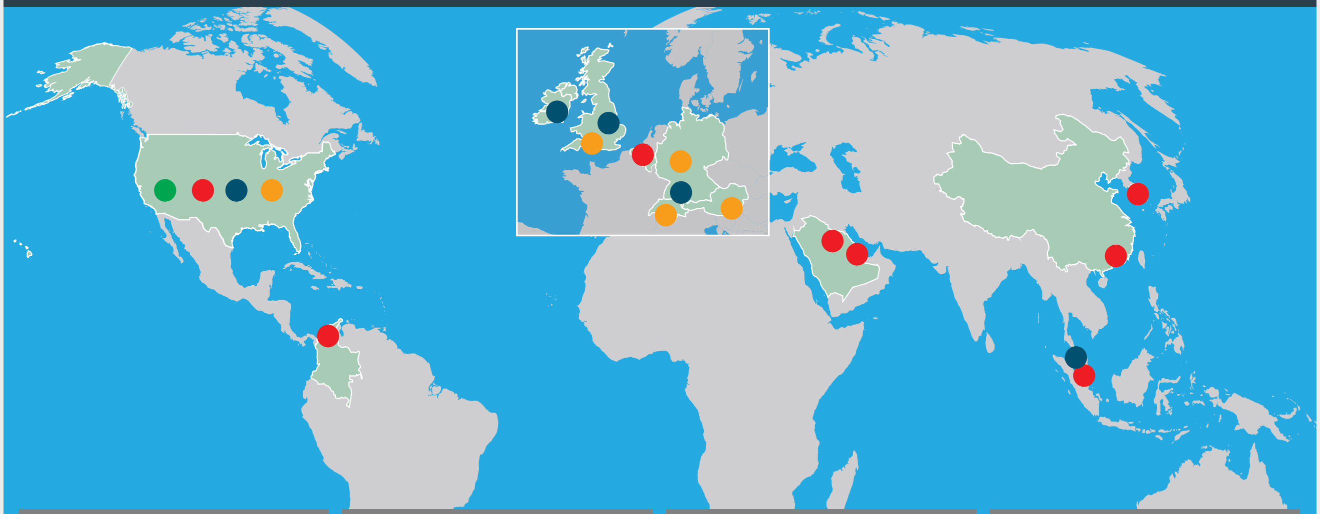
Enhance Returns

- Increase advantaged crude processing.
- Expand export capacity.
- Maintain cost discipline.

Grow Shareholder Distributions

- Annually grow dividend at double-digit rate through 2016.
- Continue share repurchase program.

WORLDWIDE OPERATIONS AS OF DEC. 31, 2013



MIDSTREAM

- 18,000+ pipeline miles
- 10,000+ railcars
- 115 MBD NGL fractionated
- 50-50 DCP joint venture

CHEMICALS

- 50-50 CPChem joint venture
- 35 manufacturing facilities
- 33 BLb/Y petrochemical and product capacity

REFINING

- 15 refineries
- 410 MBD export capacity
- 65% light-medium crudes
- 2.2 MMBD crude capacity

MARKETING & SPECIALTIES

- 10,000+ global outlets
- 2.2 MMBD marketing petroleum products sales
- 5 lubricant blending plants

COMPANY OVERVIEW

COMPETITIVE STRENGTHS

Robust Portfolio

As an energy manufacturing and logistics company that combines leading Midstream, Chemicals, Refining, and Marketing and Specialties businesses, Phillips 66 is uniquely positioned to capture opportunities of the changing energy landscape. Our businesses have the efficiency of scale and technical capability to compete in the most attractive markets globally.

Financial Strength

We hold an investment-grade credit rating on our long-term debt and maintain sufficient cash and liquidity enabling us to invest in high-return projects. Our approach to capital allocation is designed to fund sustaining investments and growth projects, while increasing shareholder distributions. As of Dec. 31, 2013, we had debt of $6.2 billion, a cash balance of $5.4 billion and a debt-to-capital ratio of 22 percent.

STRATEGIC PRIORITIES

Maintain Strong Operating Excellence

Our commitment to operating excellence guides everything we do, and it always will. Continuous improvement in safety, environmental stewardship, reliability and cost efficiency is a fundamental requirement for our company and employees. We employ rigorous training and audit programs to drive ongoing improvement in both personal and process safety as we strive for zero incidents. We are committed to protecting the environment and continually seek to reduce our environmental footprint throughout our operations.

Deliver Profitable Growth

Manufacturing and logistics capacity expansions in Midstream and Chemicals have the potential to deliver significant growth in earnings and cash flow. The businesses in our Midstream segment are pursuing multiple growth opportunities for additional fractionation and liquefied petroleum gas (LPG) export capacity, as well as gathering and processing, pipeline, storage and distribution infrastructure – driven by growing domestic unconventional crude oil, NGL and natural gas production. Over the next few years, CPChem plans to build additional processing capacity benefitting from lower-cost NGL feedstocks.

Enhance Returns on Capital

We intend to increase return on capital employed (ROCE) and capital efficiency in Refining through greater use of advantaged feedstocks, increasing refined product export capacity and increasing clean product and distillate yields from our refineries. By processing lower-cost crude oil and NGL feedstocks, our gross margins and ROCE have improved in Refining and Chemicals. We also expect to drive higher returns in Marketing and Specialties by selling finished products to higher-margin export markets. A disciplined and rigorous capital allocation process ensures that we focus investments in projects that generate competitive returns throughout the business cycle.

Grow Shareholder Distributions

We believe shareholder value is created through consistent and ongoing growth of regular dividends, supplemented by share repurchases. Regular dividends demonstrate the confidence we have in the company's capital structure and its capability to generate cash flow throughout the business cycle. The company has grown dividends

Sweeny Refinery, Old Ocean, Texas.

significantly in our first two years of operation. We plan, at the discretion of our board of directors, to increase dividends annually and fund a share repurchase program, while continuing to invest in the growth of our businesses. We expect to annually grow dividends at double-digit rates from 2014 through 2016.

Build a High-Performing Organization

Our success is primarily attributed to the contributions of our talented global workforce. We provide a great place to work where employees can reach their fullest potential, thrive on delivering results and create shareholder value through individual, team and organizational success. We foster an achievement-based culture that drives accountability and rewards performance, while investing in learning and development.

COMMERCIAL

Our Commercial organization manages the company's worldwide commodity portfolio. It partners with our Refining business to optimize our assets by procuring feedstocks with the highest economic value, minimizing laid-in cost and managing system inventory. The Commercial organization also partners with the Marketing business to ensure a dependable supply of products for wholesale customers while managing terminaling, throughput, exchange and other commercial agreements. This frees up both the Refining and Marketing and Specialties organizations to focus on operational performance. Commercial also identifies and executes location, time and quality arbitrage opportunities that generate attractive incremental returns.

In 2013, the Commercial organization was instrumental in sourcing lower-cost crude feedstocks for Phillips 66's U.S. refineries. Commercial negotiated several third-party agreements to procure and deliver more advantaged crudes to the company's facilities. As of Dec. 31, 2013, Commercial utilized 14 chartered, double-hulled crude oil and product tankers with capacities ranging in size from 300,000 to 1.1 million barrels that are primarily used to transport feedstocks to certain Phillips 66 U.S. refineries. Additionally, we have time charters on two medium-range Jones Act tankers to deliver shale crude to our Gulf and East Coast refineries.

MIDSTREAM

The 720-mile Sand Hills Pipeline began service in 2013.

Our Midstream segment consists of Phillips 66's NGL business; our Transportation business, including Phillips 66 Partners, our MLP formed in 2013; and our 50 percent interest in DCP Midstream.

MIDSTREAM OVERVIEW

OPERATING HIGHLIGHTS	2013	2012	2011
TRANSPORTATION			
Approximate miles of pipeline	18,000	18,000	17,000
Approximate number of railcars managed[1]	10,000	8,500	8,500
Crude terminals	14	10	5
Products terminals	39	39	42
Combined total recordable rate (safety incidents per 200,000 hours)	0.14	0.18	0.12
DCP MIDSTREAM (100%)			
Total natural gas throughput (TBTUD)	7.1	7.1	7.0
Midstream NGL produced (MBD)	426	402	383
Number of processing plants[2]	64	62	61
Number of NGL fractionators	12	12	12
Natural gas storage capacity (BCF)	15	9	9
Approximate miles of pipeline	67,000	63,000	62,000
Combined total recordable rate (safety incidents per 200,000 hours)	1.57	0.92	1.16
NGL			
NGL fractionated (MBD)	115	105	112

[1] Includes CPChem railcars that Phillips 66 manages.
[2] Three plants began operations and one was shut down in 2013.

2013 ACCOMPLISHMENTS

- Announced plans for the Sweeny Fractionator One and Freeport LPG Export Terminal.
- Launched an MLP through the successful initial public offering (IPO) of Phillips 66 Partners to own, develop and acquire primarily fee-based crude oil, refined petroleum products and NGL pipelines and terminals.
- Took delivery of 2,000 new crude oil railcars that meet or exceed current regulatory standards to deliver domestic advantaged crude oil to our U.S. refineries.
- Began construction on rail offloading facilities at the Bayway and Ferndale refineries.
- Began service on the 720-mile Sand Hills and 800-mile Southern Hills NGL pipelines.
- Conducted open season for the Cross-Channel Connector Pipeline, which was successfully completed in January 2014.
- DCP Midstream began commercial operations at three new gas processing plants in Colorado and Texas.

MIDSTREAM

NGL

Phillips 66 holds direct interests in three NGL fractionators and gathering systems at strategic NGL hubs in the United States. Phillips 66 owns 22.5 percent of the Gulf Coast Fractionators partnership in Mont Belvieu, Texas. The company also owns 12.5 percent of the Enterprise Mont Belvieu Fractionator and 40 percent of the Conway Fractionator, located at the Conway hub in Kansas.

In addition to fractionators, we own interests in several NGL gathering and interstate transmission pipeline systems. These systems gather and deliver raw or mixed NGL, also referred to as Y-Grade, to supply the company's facilities at its joint-venture Borger Refinery in Texas and the fractionators in Mont Belvieu and Conway.

Phillips 66 has supply and trading operations that manage NGL volume requirements for Phillips 66 refineries and fractionators. It also conducts trading at the Conway and Mont Belvieu hubs.

KEY PROJECTS

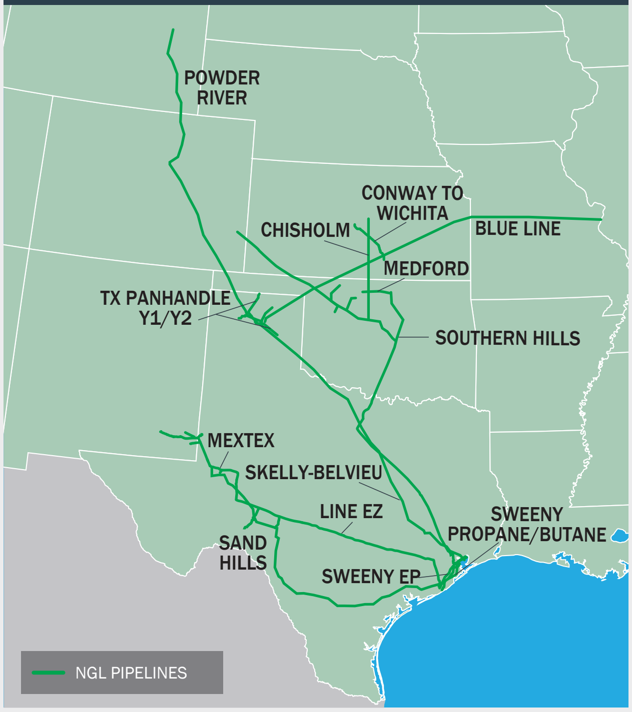
In 2013, Phillips 66 announced plans for two projects that we expect will significantly grow the value of our NGL business. The 100,000 barrel-per-day (BPD) Sweeny Fractionator One Project will be located close to our Sweeny Refinery in Old Ocean, Texas. NGL feedstock for the fractionator project will be supplied by several nearby pipelines, and products manufactured by the fractionator will be marketed to petrochemical customers in the region and exported globally.

Phillips 66 is also developing an LPG export facility at our existing marine terminal in Freeport, Texas. The new facility is intended to help meet growing global market demand for U.S.-supplied products and will leverage the company's transportation and storage infrastructure. With an expected 4.4 million barrels per month of LPG export capacity, the Freeport LPG Export Terminal will be supplied with LPG from the Mont Belvieu and Sweeny areas. A related sales contract for delivery of LPG to China was signed in March 2014.

The fractionator is expected to start up in the third quarter of 2015, with the export facility following in mid-2016. These two projects, which received board approval in early 2014, represent a total investment of more than $3 billion.

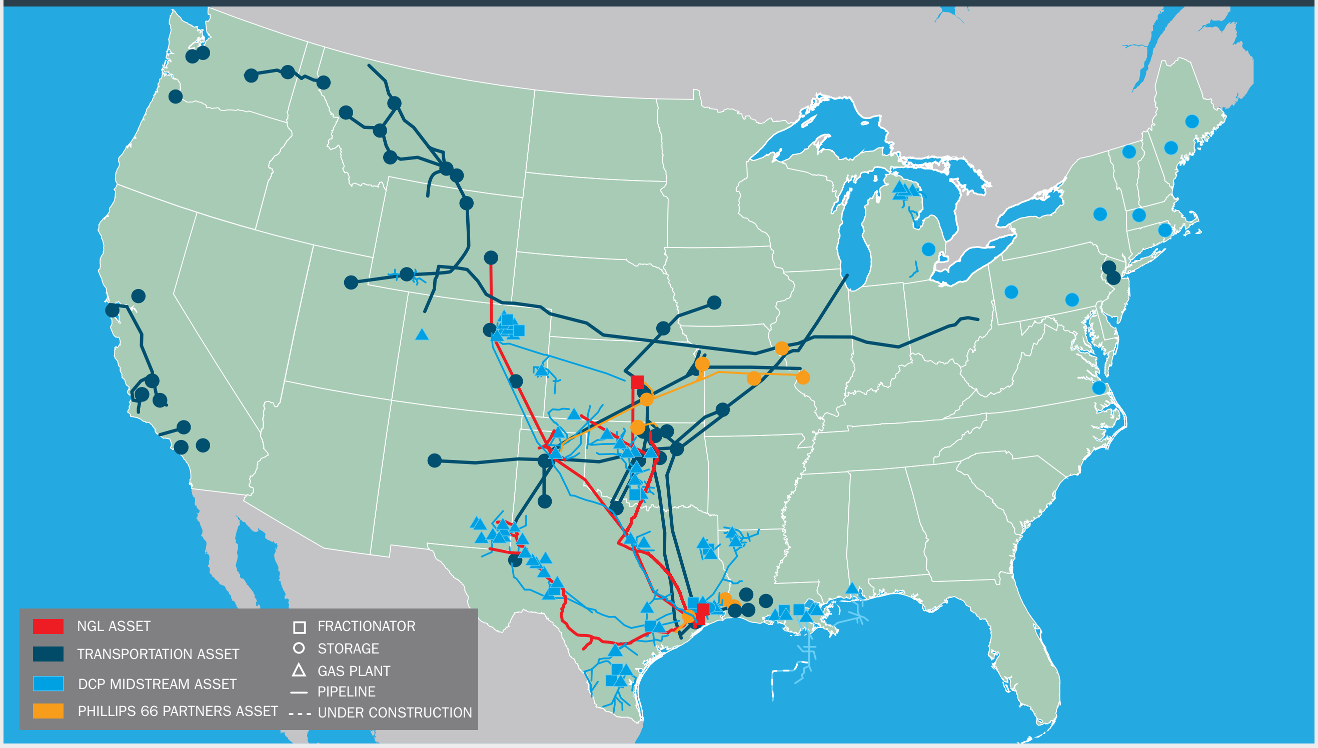
Phillips 66 holds direct one-third ownership interests in the Sand Hills and Southern Hills NGL pipelines, connecting Eagle Ford shale, Permian Basin and Midcontinent NGL production to the Mont Belvieu market. DCP Midstream operates the pipelines, which began service in 2013.

NGL PIPELINES AS OF DEC. 31, 2013*



* Includes certain NGL pipelines owned by equity affiliates.

MIDSTREAM AS OF MARCH 31, 2014



TRANSPORTATION

Phillips 66 owns or leases logistics assets to provide strategic, timely and environmentally safe delivery of crude oil, refined products, natural gas and NGL. These assets include pipeline systems; refined products, crude oil and LPG storage terminals; a petroleum coke-handling facility; marine vessels; railcars; and a trucking joint venture, Sentinel Transportation LLC.

KEY PROJECTS

Phillips 66 is investing hundreds of millions of dollars in Transportation assets to support the future success of its logistics customers, as well as Phillips 66 operations. Key among these investments is the planned acquisition of a terminal located near Beaumont, Texas. The Beaumont Terminal will be the largest terminal in the Phillips 66 portfolio and is strategically located on the U.S. Gulf Coast. It provides deep-water access and multiple interconnections with major crude oil and refined products pipelines serving 3.6 MMBD of refining capacity. The terminal also has 4.7 million barrels (MMBbl) of crude oil storage capacity and 2.4 MMBbl of refined products storage capacity; two marine docks capable of handling Aframax tankers and one barge dock; and rail and truck loading and offloading facilities. The acquisition is expected to close in the third quarter of 2014.

MIDSTREAM

Hartford Terminal, Hartford, Illinois.

The Cross-Channel Connector Pipeline, planned to be operational in the fourth quarter of 2014, will have an initial capacity for transport of up to 180,000 BPD of refined petroleum products from refineries and terminals on the south side of the Houston Ship Channel to third-party systems on the north side of the channel at Galena Park and East Houston. Additional pumping capability could bring the capacity up to 230,000 BPD.

Several notable pipeline expansions began in 2013, including pump station work on the Pioneer and Amarillo to Lubbock (SAAL) products pipeline systems. These projects were completed in early 2014. Transportation also completed projects in 2013 to increase capacity of the Powder River and Skelly-Belvieu pipelines in support of our growing NGL business in Texas.

Construction began on rail offloading facilities at the Bayway Refinery in New Jersey and the Ferndale Refinery in Washington, both of which are expected to be operational in the second half of 2014. The Bayway rail facility will have a capacity of 70,000 BPD, and the Ferndale rail facility will have a capacity of 30,000 BPD.

The company continued to add biodiesel and ethanol blending capability at its terminals in response to the Environmental Protection Agency's Renewable Fuel Standards program. Since 2012, the company has increased its overall renewable fuel blending capacity by 9 percent, including a 110 percent increase in biodiesel.

PIPELINES AND TERMINALS

As of March 31, 2014, Phillips 66 managed approximately 18,000 miles of crude oil, raw NGL, natural gas and refined products pipeline systems in the United States, including those partially owned or operated by affiliates. In addition, the company owned or operated 39 refined products terminals, 37 storage locations, five LPG terminals, 14 crude oil terminals and one petroleum coke exporting facility.

The Transportation Midcontinent Region includes nearly 3,700 miles of pipelines and more than 20 crude oil and refined products storage terminals.

MIDCONTINENT REGION AS OF MARCH 31, 2014

MIDCONTINENT REGION

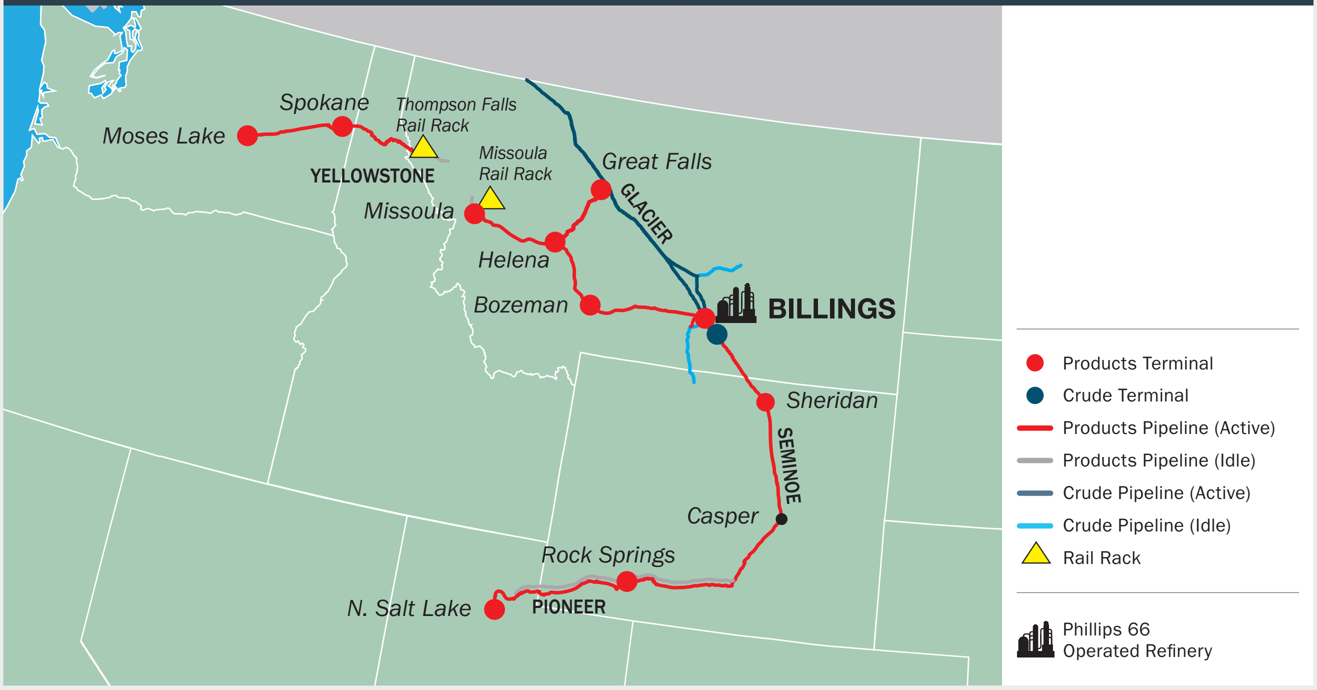
Phillips 66 has nearly 3,700 miles of pipelines and over 20 crude oil and refined products terminals in the Midcontinent Region. In addition, the company currently has a 19.5 percent interest in the Explorer Pipeline after acquiring an additional 5.7 percent interest in early 2014. Explorer is a 1,835-mile joint-interest product pipeline servicing both Midcontinent and Gulf Coast markets.

Using pipelines and trucks or the market centers in Midland, Texas, and Cushing, Oklahoma, our system delivers 100 percent of the Ponca City and Borger refineries' crude needs through local sources. The company is evaluating opportunities to increase connectivity of these assets to increase utilization, extend its reach into growing production areas and provide enhanced market access.

The company uses its extensive network of Phillips 66- and Phillips 66 Partners-owned pipelines and terminals, as well as connections to third-party systems, to distribute clean products to our large branded marketing business in the Midcontinent and Rockies regions.

MIDSTREAM

ROCKIES REGION AS OF MARCH 31, 2014

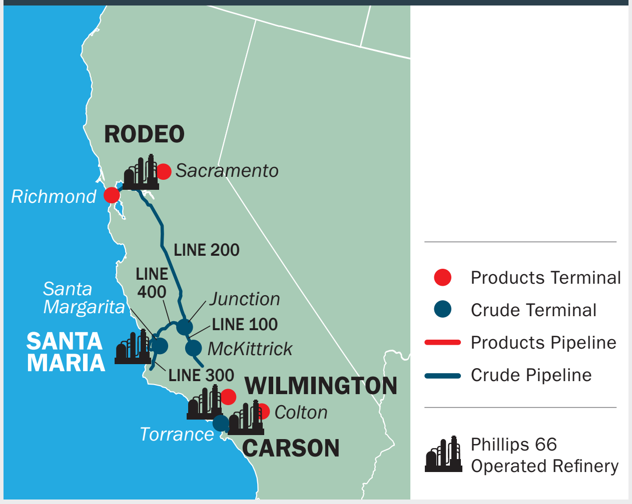


ROCKIES REGION

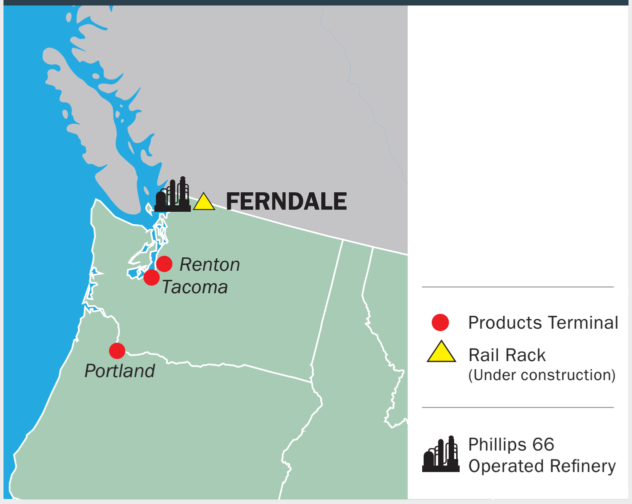
In the Rockies Region, the 865-mile Glacier Pipeline delivers Canadian crude oil to Phillips 66's Billings Refinery in Montana. The company ships clean products on approximately 1,600 miles of pipeline for placement into key branded markets in Montana, eastern Washington and Wyoming. There are 11 crude and products terminals in the system.

We recently expanded capacity on the Pioneer products system that serves Salt Lake City and accesses the UNEV Pipeline serving Las Vegas. Further projects are planned to serve growing demand in the region.

WEST COAST SOUTH REGION AS OF MARCH 31, 2014



WEST COAST NORTH REGION AS OF MARCH 31, 2014



WEST COAST REGION

In California, Phillips 66 has more than 600 miles of crude pipelines that access locally produced California crudes and marine docks for waterborne crudes. We are adding additional tankage at our Los Angeles Refinery to increase access to advantaged waterborne crudes.

On the products side, the company's network in the region includes over 100 miles of pipelines and seven terminals to service its wholesale marketing business. The Wilmington truck rack has a capacity of 75,000 BPD.

A 30,000 BPD rail offloading facility under construction at the Ferndale Refinery is expected to be operational in the second half of 2014.

MIDSTREAM

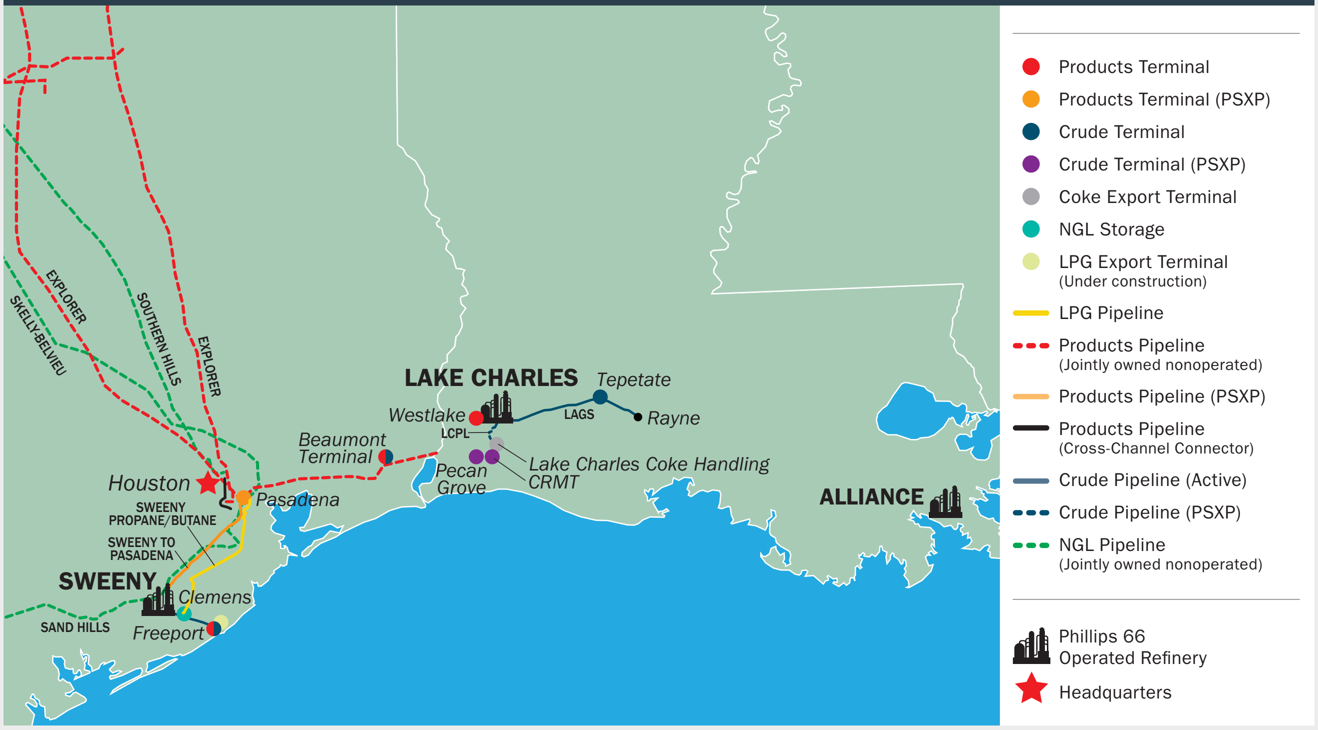
GULF COAST REGION

Phillips 66 owns and operates a number of shorter, high-capacity lines to support its 733,000 BPD of refining capacity and NGL operations on the Gulf Coast. The Gulf Coast Region contains about 300 miles of both Phillips 66- and Phillips 66 Partners-owned pipelines and six terminals.

In addition to the expanding NGL business, we are pursuing a number of projects in the region to provide our refineries and third parties access to growing U.S. and Canadian crude oil production.

The company is also increasing its product export capability in this region to meet the growing demand for motor fuels in regions outside the United States.

GULF COAST REGION AS OF MARCH 31, 2014*

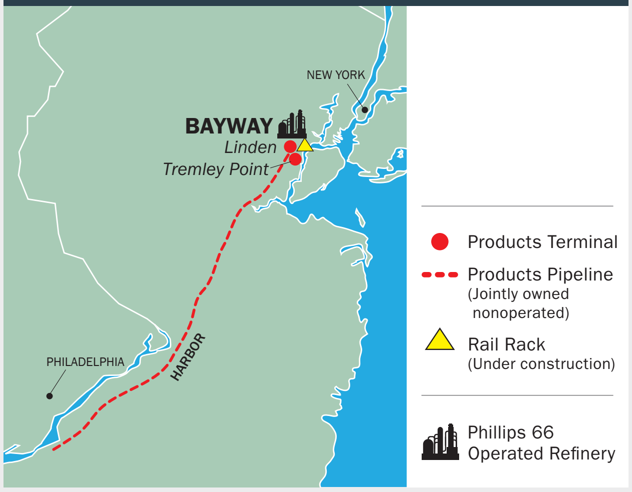


*Beaumont Terminal acquisition expected to close in the third quarter of 2014.

Phillips 66 took delivery of 2,000 new crude oil railcars in 2013, and has ordered another 1,200 crude oil railcars for delivery by the end of 2014.

Phillips 66 took delivery of 2,000 new crude oil railcars in 2013.

EAST COAST REGION AS OF MARCH 31, 2014



TRUCK AND RAIL

Phillips 66 manages truck and rail operations on behalf of its U.S. Refining and Specialties businesses. Rail movements are provided via a diverse fleet of more than 10,000 owned and leased railcars. In October 2012, we entered into an operating lease covering 2,000 new crude oil railcars that were delivered in 2013, and in early 2014, the company ordered an additional 1,200 crude oil railcars expected to be delivered by the end of 2014. These new crude railcars, which meet or exceed current government safety standards, are part of our program to increase the safe shipment of advantaged crudes into Phillips 66 refineries. Truck movements are provided through approximately 150 third-party trucking companies. In addition, a joint venture, Sentinel Transportation, provides dedicated and specialized trucking services for Phillips 66.

EAST COAST REGION

Phillips 66 operates two refined product terminals in New Jersey near our Bayway Refinery and has a 33 percent interest in a refined products pipeline in the region. A 70,000 BPD rail offloading facility, expected to start up in mid-2014, will enable the Bayway Refinery to receive advantaged crude oil deliveries by rail.

MIDSTREAM

MAJOR PIPELINE SYSTEMS *as of March 31, 2014*

NAME	ORIGINATION/TERMINUS	INTEREST (PERCENT)	SIZE	MILES	CAPACITY (MBD)
CRUDE AND FEEDSTOCKS					
Glacier	Cut Bank, MT/Billings, MT	79	8”-12”	865	100
Line 80	Gaines, TX/Borger, TX	100	8”, 12”	237	33
Line O	Cushing, OK/Borger, TX	100	10”	276	37
WA Line	Odessa, TX/Borger, TX	100	12”, 14”	289	118
Cushing	Cushing, OK/Ponca City, OK	100	18”	62	130
North Texas Crude	Wichita Falls, TX	100	2”-16”	339	28
Oklahoma Mainline	Wichita Falls, TX/Ponca City, OK	100	12”	217	100
Clifton Ridge [1] (PSXP)	Clifton Ridge, LA/Westlake, LA	75	20”	10	300
Louisiana Crude Gathering	Rayne, LA/Westlake, LA	100	4”-8”	85	25
Sweeny Crude	Sweeny, TX/Freeport, TX	100	12”, 24”, 30”	31	295
Sweeny Crude Butadiene [2]	Clemens, TX/Webster, TX	100	4”, 6”	68	7
Coast and Valley System	Central CA/Bay Area, CA	100	8”-16”	602	307
PETROLEUM PRODUCTS					
Harbor	Woodbury, NJ/Linden, NJ	33	16”	80	104
Pioneer [1]	Sinclair, WY/Salt Lake City, UT	50	8”, 12”	562	63
Seminoe	Billings, MT/Sinclair, WY	100	6”-10”	342	33
Yellowstone	Billings, MT/Moses Lake, WA	46	6”-10”	710	66
Borger to Amarillo	Borger, TX/Amarillo, TX	100	8”, 10”	93	76
ATA Line	Amarillo, TX/Albuquerque, NM	50	6”, 10”	293	20
Borger-Denver	McKee, TX/Denver, CO	70	6”-12”	405	38
Gold Line [1] (PSXP)	Borger, TX/East St. Louis, IL	75	8”-16”	681	120
SAAL	Amarillo, TX/Amarillo and Lubbock, TX	33	6”	121	18
Cherokee 8”	Ponca City, OK/Oklahoma City, OK	100	8”	90	46
Heartland [3]	McPherson, KS/Des Moines, IA	50	8”, 6”	49	30
Paola Products [1] (PSXP)	Paola, KS/Kansas City, KS	75	8”, 10”	106	96
Standish	Marland Junction, OK/Wichita, KS	100	18”	92	80
Wichita/Ark City 1&2	Ponca City, OK/Wichita, KS	100	8”, 10”	105	55
Wood River	Medford, OK/Mt. Vernon, MO	100	10”, 12”	287	45
Explorer	Texas Gulf Coast/Chicago, IL	19	24”, 28”	1,835	500
Sweeny to Pasadena [1] (PSXP)	Sweeny, TX/Pasadena, TX	75	12”, 18”	120	264
LA Basin	Los Angeles, CA	100	6”- 20”	89	357
Richmond	Rodeo, CA/Richmond, CA	100	6”	14	26
NGL					
Powder River	Sage Creek, WY/Borger, TX	100	6”-8”	695	19
Skelly-Belvieu	Skellytown, TX/Mont Belvieu, TX	50	8”	571	45
TX Panhandle Y1/Y2	Sherhan, TX/Borger, TX	100	3”-10”	299	73
Chisholm	Kingfisher, OK/Conway, KS	50	4”-10”	202	42
Line EZ [2]	Benedum, TX/Sweeny, TX	100	10”	434	101
MexTex [2]	Artesia, NM/Benedum, TX	100	4”-12”	305	51
Sweeny EP [2]	Mont Belvieu, TX/Sweeny, TX	100	8”	85	40
Sand Hills [4]	Permian Basin/Mont Belvieu, TX	33	20”	720	200
Southern Hills [4]	U.S. Midcontinent/Mont Belvieu, TX	33	20”	800	175
LPG					
Blue Line	Borger, TX/East St. Louis, IL	100	8”-12”	667	29
Conway to Wichita	Conway, KS/Wichita, KS	100	12”	55	38
Medford	Ponca City, OK/Medford, OK	100	4”-6”	42	15, 60
Sweeny Propane/Butane [2]	Clemens, TX/Pasadena, TX	100	8”	65	31
NATURAL GAS					
Rockies Express	Meeker, CO/Clarington, OH	25	36”-42”	1,679	1.8 BCFD

[1] Ownership interest excludes noncontrolling interests.
[2] 100 percent interest held by CPChem. Operated by Phillips 66.
[3] Total pipeline system is 419 miles. Phillips 66 has ownership interest in multiple segments totaling 49 miles.
[4] Phillips 66 has a direct one-third ownership in the pipeline entities; operated by DCP Midstream.

FINISHED PRODUCTS TERMINALS *as of March 31, 2014*

FACILITY NAME	LOCATION	STORAGE CAPACITY (MBbl)	RACK CAPACITY (MBD)
Albuquerque	New Mexico	244	18
Amarillo	Texas	277	26
Billings	Montana	88	16
Bozeman	Montana	113	13
Colton	California	211	21
Denver	Colorado	310	36
Des Moines	Iowa	206	15
East St. Louis (PSXP)	Illinois	2,245	78
Freeport*	Texas	1,151	N/A
Glenpool	Oklahoma	366	17
Great Falls	Montana	157	12
Hartford (PSXP)	Illinois	1,075	25
Helena	Montana	178	10
Jefferson City (PSXP)	Missouri	110	16
Kansas City (PSXP)	Kansas	1,294	66
La Junta	Colorado	101	10
Lincoln	Nebraska	219	21
Linden	New Jersey	429	121
Lubbock	Texas	179	17
Missoula	Montana	348	29
Moses Lake	Washington	186	10
Mount Vernon	Missouri	363	46
North Salt Lake	Utah	657	41
Oklahoma City	Oklahoma	341	48
Pasadena (PSXP)	Texas	3,210	65
Ponca City	Oklahoma	51	23
Portland	Oregon	664	33
Renton	Washington	228	20
Richmond	California	334	28
Rock Springs	Wyoming	125	19
Sacramento	California	141	13
Sheridan	Wyoming	86	15
Spokane	Washington	351	24
Tacoma	Washington	307	17
Tremley Point	New Jersey	1,593	39
Westlake	Louisiana	128	16
Wichita Falls	Texas	303	15
Wichita North (PSXP)	Kansas	679	12
Wichita South	Kansas	216	21
Wilmington	California	161	75

CRUDE AND OTHER TERMINALS *as of March 31, 2014*

FACILITY NAME	LOCATION	STORAGE CAPACITY (MBbl)
Billings	Montana	270
Borger	Texas	678
Clifton Ridge Marine Terminal (PSXP)	Louisiana	3,410
Cushing	Oklahoma	700
Freeport*	Texas	955
Junction	California	523
Lake Charles, Coke Handling	Louisiana	N/A
McKittrick	California	237
Odessa	Texas	523
Pecan Grove (PSXP)	Louisiana	142
Ponca City	Oklahoma	1,200
Santa Margarita	California	335
Santa Maria	California	112
Tepetate	Louisiana	152
Torrance	California	309
Wichita Falls	Texas	240

* Refining asset.

MIDSTREAM

Phillips 66 Partners is a growth-oriented, traditional MLP formed by Phillips 66 as part of our strategy to grow our Midstream business.

PHILLIPS 66 PARTNERS

Phillips 66 Partners is a growth-oriented, traditional MLP formed by Phillips 66 as part of our strategy to grow our Midstream business. The partnership was formed to own, operate, develop and acquire primarily fee-based crude oil, refined petroleum products and NGL pipelines and terminals, and other transportation and midstream assets. Phillips 66 Partners successfully completed its IPO in July 2013, and its units trade on the New York Stock Exchange under the ticker symbol PSXP.

Phillips 66 has majority ownership of Phillips 66 Partners and acts as the general partner with full management and operating responsibility for the business. The remaining noncontrolling interest, consisting of limited partner common units, was sold in the IPO.

We believe that Phillips 66 Partners provides value to Phillips 66 shareholders, highlights the value of our logistics and infrastructure assets, and will be an integral vehicle to support growth in transportation and midstream infrastructure.

Headquartered in Houston, the partnership's initial assets at completion of the IPO included the Clifton Ridge crude oil pipeline, terminal and storage system in Louisiana; the Sweeny to Pasadena refined petroleum products pipeline, terminal and storage system in Texas; and the Hartford Connector refined petroleum products pipeline, terminal and storage system in Illinois.

On March 1, 2014, Phillips 66 Partners executed its first post-IPO acquisition, purchasing from Phillips 66 the Gold Line products system, an interstate refined petroleum products pipeline, terminal and storage system running from Texas to Illinois, and two refinery-grade propylene storage spheres in Medford, Oklahoma.

The partnership will continue to pursue acquisitions from Phillips 66 and third parties, as well as organic growth opportunities, which we expect will allow it to deliver top-quartile distribution growth.

PHILLIPS 66 PARTNERS AS OF MARCH 31, 2014

PHILLIPS 66 PARTNERS[1] *as of March 31, 2014*

PIPELINES

NAME	ORIGINATION/TERMINUS	SIZE	MILES	CAPACITY (MBD)
CRUDE OIL PIPELINES				
Clifton Ridge Crude System				
	Clifton Ridge/Lake Charles Refinery	20”	10	300
	Pecan Grove/Clifton Ridge	12”	0.6	84
	Shell/Clifton Ridge	20”	0.6	312
PETROLEUM PRODUCTS PIPELINES				
Sweeny to Pasadena Products System				
	Sweeny Refinery/Pasadena, TX	12”	60	125
	Sweeny Refinery/Pasadena, TX	18”	60	138
Hartford Connector Products System				
	Wood River Refinery/Hartford, IL	12”	3	80
	Hartford, IL/Explorer Pipeline	24”	1	430
Gold Line Products System				
	Borger Refinery/Wichita, KS	16”	273	120
	Wichita, KS/Paola, KS	16”	143	132
	Paola, KS/East St. Louis, IL	8”-12”	265	53
	Paola, KS/Kansas City, KS	8”	53	24
	Paola, KS/Kansas City, KS	10”	53	72

TERMINALS AND STORAGE ASSETS

NAME	TANK SHELL STORAGE CAPACITY (MBbl)	RACK CAPACITY (MBD)
Clifton Ridge Crude System		
Clifton Ridge Terminal	3,410	12
Pecan Grove Storage	142	N/A
Sweeny to Pasadena Products System		
Pasadena Terminal	3,210	65
Hartford Connector Products System		
Hartford Terminal	1,075	25
Gold Line Products System		
East St. Louis Terminal	2,245	78
Jefferson City Terminal	110	16
Kansas City Terminal	1,294	66
Wichita North Terminal	679	12
Medford Spheres[2]	70	N/A

MARINE ASSETS

NAME	THROUGHPUT CAPACITY (Thousands of barrels per hour)
Clifton Ridge Crude System	
Clifton Ridge Ship Dock	48
Pecan Grove Barge Dock	6
Hartford Connector Products System	
Hartford Barge Dock	3

[1] Phillips 66 Partners ownership percentage for assets listed above is 100 percent.

[2] Medford Spheres are newly constructed assets that began operations in March 2014.

MIDSTREAM

DCP MIDSTREAM

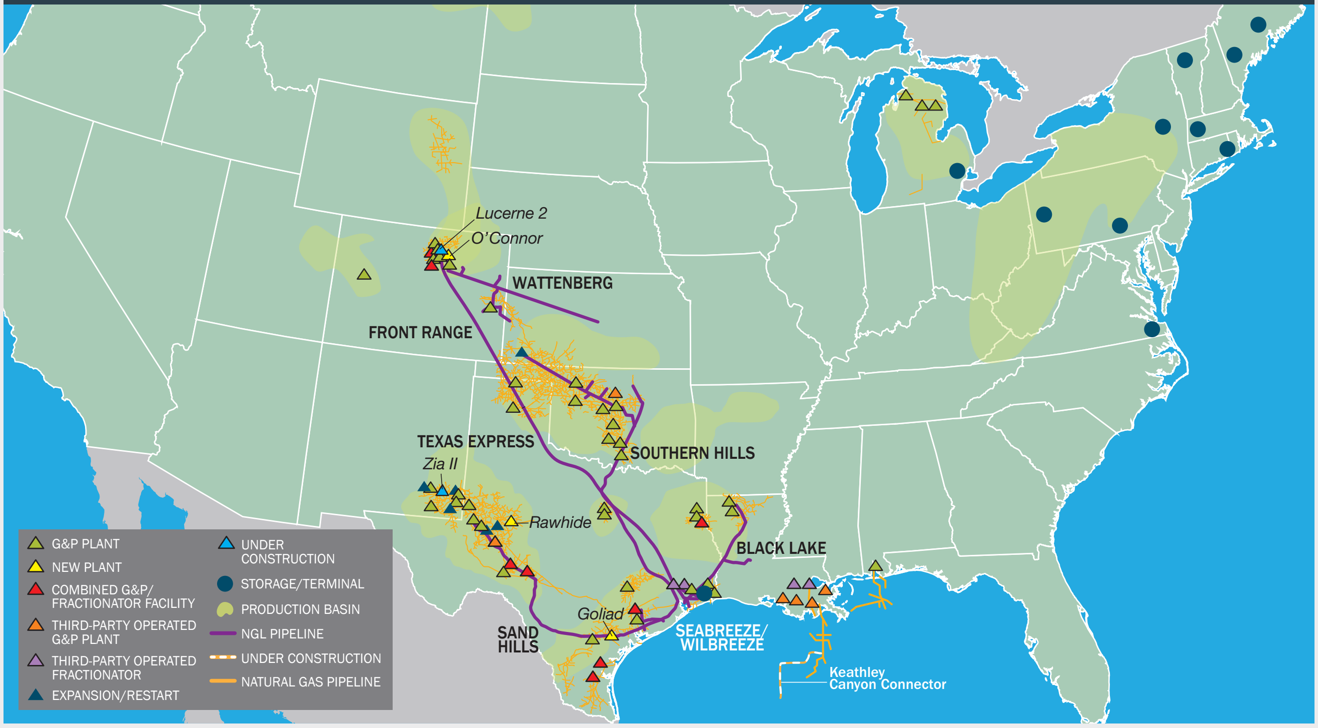
DCP Midstream is equally owned by Phillips 66 and Spectra Energy. Headquartered in Denver, Colorado, DCP Midstream leads the midstream industry as one of the nation's largest natural gas gatherers and processors and one of the largest producers and marketers of NGL in the United States. Operations include gathering and transporting raw natural gas and NGL through approximately 67,500 miles of pipeline as of March 31, 2014. The collected gas is processed at 64 owned or operated plants and treaters. Additionally, DCP Midstream owns or operates 12 NGL fractionators.

In 2005, DCP Midstream sponsored an MLP, DCP Midstream Partners LP (DCP Partners). DCP Partners gathers, compresses, treats, processes, transports, stores and sells natural gas. It also produces, fractionates, transports, stores and sells NGL, and recovers and sells condensate. DCP Partners is also a leading distributor of propane. The partnership's units trade on the New York Stock Exchange under the ticker symbol DPM.

Through recent additions of the Sand Hills, Southern Hills, Texas Express and Front Range pipelines, DCP Midstream has approximately 4,500 miles of NGL pipelines across its system as of March 31, 2014, more than double what it had in 2010. These pipelines connect plants in the Front Range, Midcontinent, Permian and Eagle Ford basins to premium markets on the Texas Gulf Coast.

DCP Midstream is a large integrated service provider with strategically located assets in liquids-rich developments. Growing industry demand continues to drive infrastructure needs and provide attractive

DCP MIDSTREAM AND DCP MIDSTREAM PARTNERS ASSETS AS OF MARCH 31, 2014



DCP Midstream is one of the nation's largest natural gas gatherers and processors, and one of the largest producers and marketers of NGL in the United States.

DCP OPERATING DATA *as of March 31, 2014*

NAME	GAS AND NGL GATHERING AND TRANSMISSION SYSTEMS (MILES)	OWNED AND OPERATED PLANTS	PLANTS OPERATED BY THIRD-PARTY	FRACTIONATORS	PLANT THROUGHPUT (TBtu/d)	NGL PRODUCTION (MBbl/d)
REGION						
Midcontinent	29,900	12	1	-	1.9	122
Permian	18,200	16	1	1	1.3	134
East Texas-North Louisiana	2,400	5	-	1	0.8	35
Eagle Ford	6,100	7	-	3	1.2	76
Rocky Mountain	4,800	9	-	-	0.7	52
Gulf Coast	1,400	4	-	2	0.4	21
Barnett Shale	200	2	4	-	-	5
Antrim Shale	500	3	-	-	0.2	-
Logistics	4,000	-	-	5	-	-
Total	**67,500**	**58**	**6**	**12**	**6.5**	**445**

expansion opportunities. DCP Midstream expects to execute $4 billion to $6 billion in growth projects from 2014 to 2016.

KEY PROJECTS

The 800-mile Southern Hills Pipeline provides improved market access for growing Midcontinent NGL production. Extensions lead to the Mont Belvieu market hub and various receipt points in the Midcontinent. The pipeline was placed in service in the second quarter of 2013. Phillips 66, Spectra Energy Partners and DCP Partners each own a one-third interest in the entity that owns the pipeline. The regulated, common-carrier pipeline will ramp up to a capacity of 175,000 BPD after completion of planned pump stations in 2014.

The 720-mile Sand Hills Pipeline was developed to meet growing demand in the Permian Basin and Eagle Ford shale. Service from the Eagle Ford shale began in December 2012, and deliveries from the Permian Basin started in the second quarter of 2013. Phillips 66, Spectra Energy Partners and DCP Partners each own a one-third interest in the entity that owns the pipeline. The common-carrier pipeline has a capacity of more than 200,000 BPD after completion of initial pump stations in early 2014. Further capacity increases to 350,000 BPD are possible with the installation of additional pump stations.

DCP Partners began operations at several newly built natural gas processing plants in 2013, including the 200 million-cubic-feet-per-day (MMCFD) Eagle Plant near Edna, Texas, and the 110 MMCFD O'Connor Plant near Kersey, Colorado. One of DCP Partners' joint-venture assets, the approximately 580-mile Texas Express Pipeline, began operations in late 2013 to deliver NGL to Mont Belvieu. DCP Midstream's 75 MMCFD Rawhide Plant in Glasscock County, Texas, also began operations in 2013.

In the first quarter of 2014, DCP Partners' 200 MMCFD Goliad Plant in Goliad, Texas, began operations. Additionally, in the first quarter of 2014, an expansion of DCP Partners' O'Connor Plant in the Denver-Julesburg Basin increased the plant's capacity to 160 MMCFD. Another of DCP Partners' joint-venture projects, the approximately 435-mile Front Range Pipeline, was placed into service in the first quarter of 2014. The pipeline transports NGL from the Denver-Julesburg Basin to the Texas Express Pipeline.

DCP Partners also holds an ownership interest in a joint venture that is constructing the Keathley Canyon Connector, a 215-mile subsea natural gas gathering pipeline for production from the Keathley Canyon, Walker Ridge and Green Canyon areas in the central deep-water Gulf of Mexico. The pipeline is expected to be completed in the fourth quarter of 2014.

In the first half of 2014, DCP Midstream announced plans to build a 200 MMCFD sour natural gas processing plant, the Zia II Plant, with associated gathering system expansions in the Permian Basin. The Zia II Plant is expected to start up during the first half of 2015. DCP Partners plans to complete construction and place into service the 200 MMCFD Lucerne 2 Plant in the Denver-Julesburg Basin in mid-2015.

CHEMICALS

In the second quarter of 2014, CPChem began operations at the world's largest on-purpose 1-hexene plant at its Cedar Bayou facility in Baytown, Texas.

Phillips 66's Chemicals segment comprises a 50 percent equity investment in CPChem.

CHEMICALS OVERVIEW

OPERATING HIGHLIGHTS – CPCHEM (100%)	2013	2012	2011
Number of manufacturing sites	35	36	35
Plant gross capacity (BLb/Y)	48	48	41
Net capacity (BLb/Y)	33	34	31
Combined total recordable rate (safety incidents per 200,000 hours)	0.34	0.30	0.41
Employees at year-end (thousands)	5.0	4.7	4.7
Olefins and polyolefins capacity utilization	88	93	94

2013 CPCHEM ACCOMPLISHMENTS

- Received final investment approval to build its world-scale $6 billion USGC Petrochemicals Project, including a 3.3 billion-pound-per-year (BLb/Y) ethane cracker and two 1.1 BLb/Y polyethylene facilities.
- Completed a 22,000 BPD NGL fractionator expansion at its Sweeny facility.
- Increased normal alpha olefins capacity by 75 million pounds per year (MMLb/Y) and completed a study to further expand normal alpha olefin capacity at its Cedar Bayou facility. In June 2014, CPChem received final investment approval for the 220 MMLb/Y expansion project.
- Announced plans to expand its ethylene production by 200 MMLb/Y by adding a 10th furnace to an ethylene unit at its Sweeny facility.
- Completed sale of polystyrene plant located in Zhangjiagang, China.
- CPChem continued construction in 2013 on the world's largest on-purpose 1-hexene plant at its Cedar Bayou facility in Baytown, Texas. The plant began operations in the second quarter of 2014.

CHEMICALS

CPCHEM PROFILE

Headquartered in The Woodlands, Texas, CPChem had approximately 5,000 employees worldwide and approximately $11 billion in assets as of Dec. 31, 2013. CPChem's business is structured around two primary operating segments: Olefins and Polyolefins (O&P), and Specialties, Aromatics and Styrenics (SA&S). The O&P segment produces and markets ethylene, propylene and other olefins products. The majority of the ethylene is consumed within the O&P segment for the production of polyethylene, normal alpha olefins and polyethylene pipe. The SA&S segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane, as well as polystyrene and styrene-butadiene copolymers. SA&S also manufactures and markets a variety of specialty chemical products, including organosulfur chemicals, solvents, drilling chemicals, mining chemicals and high-performance engineering plastics and compounds.

CPCHEM IS THE:

- Largest producer of high-density polyethylene in the world.
- Fourth-largest ethylene producer in North America.
- Second-largest cyclohexane producer and largest cyclohexane marketer in the world.
- Second-largest alpha olefins producer in the world.

CPCHEM'S PRIMARY BRANDS INCLUDE:

- Marlex® polyethylene, a premium extrusion and rigid packaging resin.
- MarFlex® polyethylene, a superior flexible packaging resin.
- K-Resin® styrene-butadiene copolymer (SBC), the number one brand of SBC in the world.
- Soltex® drilling mud additive, a high-temperature/high-pressure fluid loss control additive for water-based muds.
- Scentinel® Gas Odorants, which are added to natural gas to give it a distinctive smell, a vital safety measure.

CPCHEM WORLDWIDE OPERATIONS AS OF DEC. 31, 2013

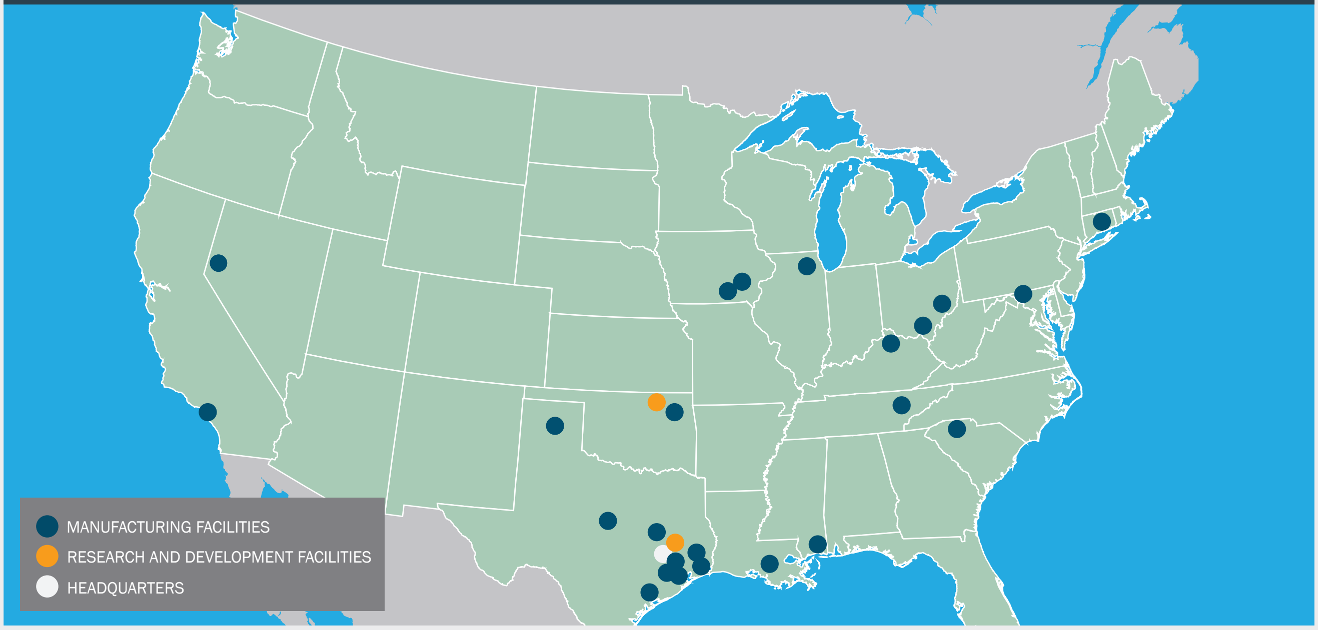
CPChem, through its subsidiaries and equity affiliates, has 35 manufacturing sites located in Belgium, China, Colombia, Qatar, Saudi Arabia, Singapore, South Korea and the United States. In addition, CPChem has two research and development centers. These facilities provide petrochemical and polymer research and an advanced analytical sciences group to support new catalyst development, product and process development, and commercial process support for all of its major product lines. CPChem employs more than 260 scientists, researchers and engineers in its research facilities.

CPChem's state-of-the-art plastics technical center is equipped with the latest processing and testing technology for the molding and extruding of polymer and copolymer resins.

CPChem's loop slurry process for high-density polyethylene production is one of the most widely licensed processes in the world, with more than 80 commercial reactor facilities utilizing this technology. Another technological achievement is CPChem's proprietary Aromax® technology, the lowest-cost process for on-purpose production of benzene.

Other technological achievements and proprietary technologies include: on-purpose 1-hexene technology; normal alpha olefin and polyalphaolefin production technology; proprietary acetylene reduction catalyst technology; K-Resin® SBC technology; methyl mercaptan process technology; and first- and second-generation functional drilling fluid technology.

CPCHEM U.S. OPERATIONS AS OF DEC. 31, 2013



CHEMICALS

KEY PROJECTS

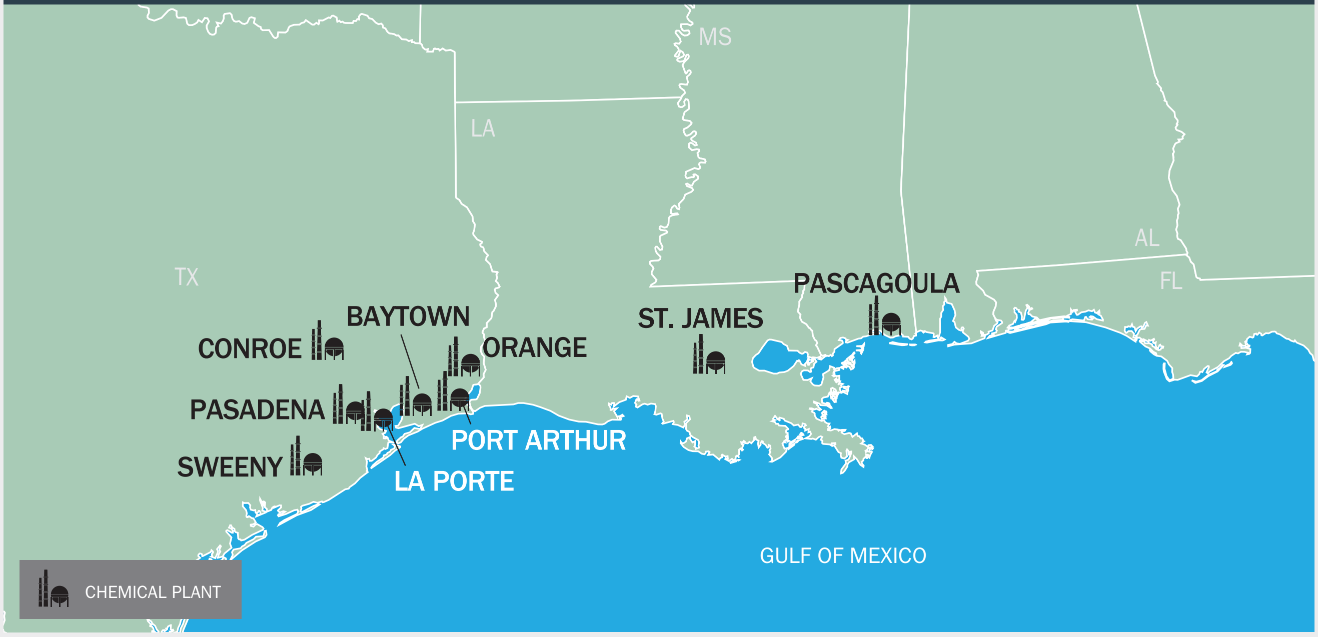
The development of shale gas resources in the United States provides significant opportunities on the U.S. Gulf Coast for CPChem. The rise in shale oil and natural gas production creates cost-advantaged NGL feedstocks and lower energy costs.

During 2013, CPChem completed an NGL fractionator expansion at its Sweeny facility. The project increased capacity by 22,000 BPD or 19 percent.

In 2013, CPChem received final investment approval to build its world-scale USGC Petrochemicals Project. The project includes a 3.3 BLb/Y ethane cracker to be built at CPChem's Cedar Bayou facility in Baytown, Texas, and two 1.1 BLb/Y polyethylene facilities that will be located near its Sweeny facility in Old Ocean, Texas. It will be one of the first major cracker complexes developed on the Gulf Coast since the shale production boom and will utilize lower-priced ethane feedstock. The approximately $6 billion project is scheduled to start up in 2017 and is expected to increase CPChem's U.S. ethylene capacity by more than 40 percent.

CPChem's Cedar Bayou facility in Baytown, Texas.

CPCHEM U.S. GULF COAST MANUFACTURING FACILITIES AS OF DEC. 31, 2013



CPChem's $6 billion USGC Petrochemical Project will include one of the first major ethane cracker complexes developed on the Gulf Coast since the shale production boom began.

Another of CPChem's projects is the world's largest on-purpose 1-hexene plant at its Cedar Bayou facility. The plant began operations in the second quarter of 2014 and has capacity of 550 MMLb/Y. The primary product, 1-hexene, is a key component in the manufacturing of polyethylene, a plastic resin commonly converted into film, pipe, detergent bottles and food and beverage containers.

In June 2014, CPChem received final investment approval to expand its normal alpha olefin capacity at Cedar Bayou. After achieving 75 MMLb/Y of additional capacity through a number of small projects in 2013, the incremental expansion is expected to add 220 MMLb/Y to the current capacity of 1.6 BLb/Y in a phased approach. The project is anticipated to be completed in July 2015.

CPChem also announced plans to expand its ethylene production by 200 MMLb/Y by adding a 10th furnace to an ethylene unit at its Sweeny facility. The project is expected to start up in the third quarter of 2014.

CPChem expanded its sulfur-based products capacity at its Tessenderlo, Belgium, facility by more than 40 percent. Construction was completed in the second quarter of 2014.

Saudi Polymers Company plant in Jubail Industrial City, Saudi Arabia.

CPCHEM MIDDLE EAST MANUFACTURING FACILITIES
AS OF DEC. 31, 2013

CHEMICALS

CPCHEM NET PETROCHEMICAL AND PLASTICS PRODUCTION CAPACITIES *as of Dec. 31, 2013*

MMLB/Y	U.S.	MIDDLE EAST	WORLDWIDE
O&P			
Ethylene	7,830	2,475	10,305
Propylene	2,675	505	3,180
High-density polyethylene	4,205	1,725	6,500
Low-density polyethylene	620	-	620
Linear low-density polyethylene	490	-	490
Polypropylene	-	310	310
Normal alpha olefins	1,565	515	2,080
Polyalphaolefins	105	-	235
Polyethylene pipe	590	-	590
Total O&P	18,080	5,530	24,310
SA&S			
Benzene	1,600	930	2,530
Cyclohexane	1,060	395	1,455
Paraxylene	1,000	-	1,000
Styrene	1,050	825	1,875
Polystyrene	835	155	1,070
K-Resin® SBC	100	-	170
Specialty chemicals	555	-	655
Ryton® PPS	61	-	81
Total SA&S	6,261	2,305	8,836

WHOLLY OWNED CPCHEM FACILITIES *as of Dec. 31, 2013*

FACILITY/LOCATION	PRODUCTS	CAPACITY (MMLB/Y)
Pasadena Plastics Complex, Pasadena, TX	K-Resin® SBC High-density polyethylene	100 2,180
Sweeny Facility, Old Ocean, TX	Ethylene Propylene	4,110 870
Borger Facility, Borger, TX	Organosulfur chemicals Ryton® PPS polymer Performance and reference fuels High-purity hydrocarbons and solvents Mining chemicals	180 40 120 140 70
Cedar Bayou Facility, Baytown, TX	Ethylene Propylene Normal alpha olefins Polyalphaolefins Linear low-, low- and high-density polyethylene	1,840 1,030 1,565 105 2,625
Orange Chemical Facility, Orange, TX	High-density polyethylene	970
Port Arthur Facility, Port Arthur, TX	Ethylene Propylene Cyclohexane	1,880 775 1,060
Drilling Specialties, Conroe, TX	Drilling specialty chemicals	45
Houston Compounding Facility, La Porte, TX	Ryton® PPS compounds	21
Pascagoula Facility, Pascagoula, MS	Paraxylene Benzene	1,000 1,600
Performance Pipe Division, nine locations in the United States	Polyethylene pipe and pipe fittings	590
Tessenderlo Chemicals Facility, Tessenderlo, Belgium	Organosulfur chemicals	100
Kallo Compounding Facility, Kallo-Beveren, Belgium	Ryton® PPS compounds	20
Beringen, Belgium Facility, Beringen, Belgium	Polyalphaolefins	130

JOINT-VENTURE CPCHEM FACILITIES *as of Dec. 31, 2013*

FACILITY/LOCATION	CPCHEM OWNERSHIP (PERCENT)	PRODUCTS	GROSS CAPACITY (MMLB/Y)
Americas Styrenics, St. James, LA	50	Styrene	2,100
Americas Styrenics, Joliet, IL	50	Polystyrene	270
Americas Styrenics, Allyn's Point, CT	50	Polystyrene	250
Americas Styrenics, Hanging Rock, OH	50	Polystyrene	400
Americas Styrenics, Torrance, CA	50	Polystyrene	330
Americas Styrenics, Marietta, OH	50	Polystyrene	420
Americas Styrenics, Cartagena, Colombia	50	Polystyrene	160
Qatar Chemical Company Ltd., Mesaieed, Qatar	49	Ethylene	1,150
		High-density polyethylene	1,010
		1-hexene	130
Qatar Chemical Company II Ltd., Mesaieed, Qatar	49	High-density polyethylene	770
		Normal alpha olefins	760
Ras Laffan Olefins Company (RLOC), Ras Laffan, Qatar	26	Ethylene	2,870
Chevron Phillips Singapore, Chemicals (Private) Limited, Singapore	50	High-density polyethylene	880
Shanghai Golden Phillips Petrochemical Co., Jinshanwei, China	40	High-density polyethylene	320
Saudi Polymers Company, Jubail Industrial City, Saudi Arabia	35	Ethylene	2,690
		Propylene	970
		High-density polyethylene	2,425
		Polypropylene	880
		Polystyrene	440
		1-hexene	220
Saudi Chevron Phillips Company, Jubail Industrial City, Saudi Arabia	50	Benzene	1,865
		Cyclohexane	790
Jubail Chevron Phillips Company, Jubail Industrial City, Saudi Arabia	50	Styrene	1,650
		Ethylene	450
		Propylene	330
K R Copolymer Co., Ltd., Yeosu, South Korea	60	K-Resin® SBC	115

REFINING

With a gross crude oil processing capacity of 314,000 BPD, the Wood River Refinery in Roxana, Illinois, is the largest refinery in the Phillips 66 portfolio.

Phillips 66's U.S. Refining assets are integrated with Transportation, Marketing and Commercial activities. Phillips 66 also owns or has an interest in three refineries in Europe and one refinery in Asia.

REFINING OVERVIEW

OPERATING HIGHLIGHTS	2013	2012	2011
Crude oil processed (MBD)	2,079	2,064	2,166
Crude oil capacity utilization (percent)	93	93	92
Clean product yield (percent)	84	84	84
Distillate yield (percent)	40	40	40
U.S. crude processing capacity (MBD)	1,816[1]	1,806[2]	1,801
International crude processing capacity (MBD)	430	430	426
Worldwide crude processing capacity (MBD)	2,246[1]	2,236[2]	2,227
Combined total recordable rate (safety incidents per 200,000 hours)	0.26	0.23	0.35

[1] As of Jan. 1, 2014.

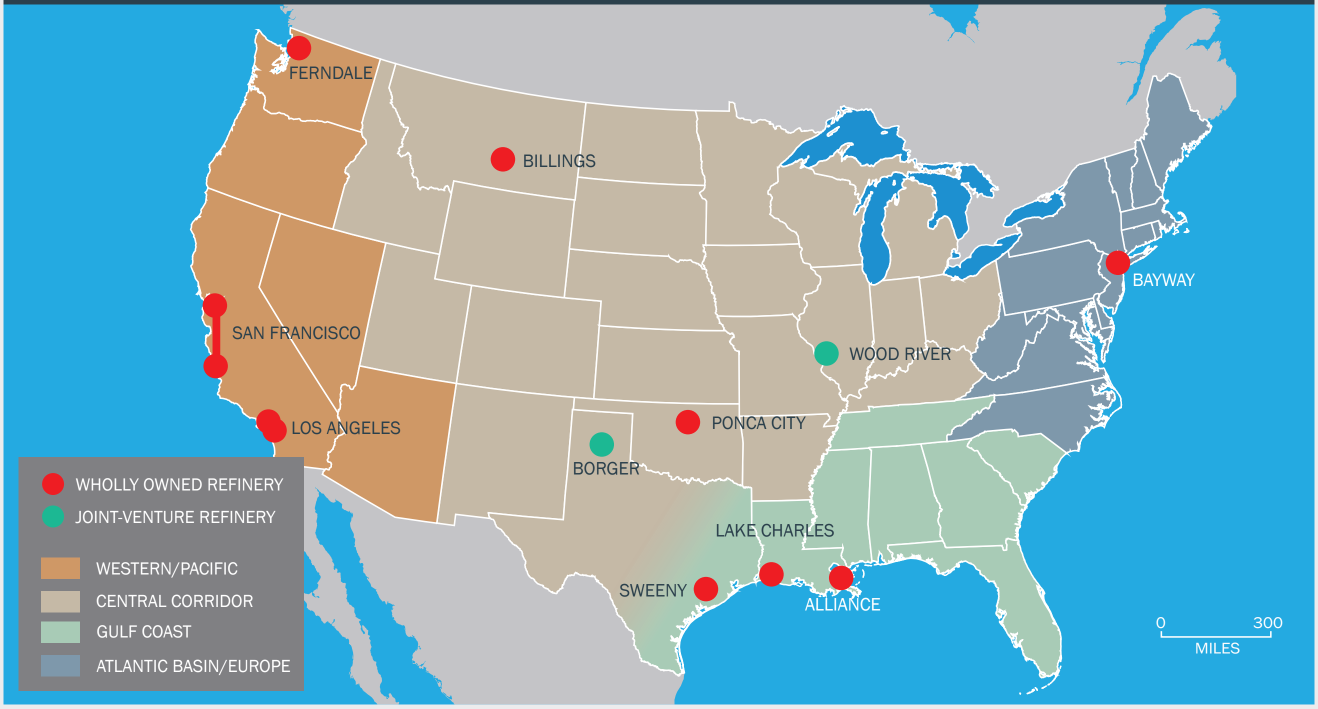
[2] As of Jan. 1, 2013.

2013 ACCOMPLISHMENTS

- Ongoing focus on safety, with multiple facilities earning external recognition for superior safety performance during the year.
- Increased domestic advantaged crude processing to 74 percent of total crude runs in 2013, compared to 62 percent in 2012.
- Captured strong refining margins in the Central Corridor Region.
- Continuing improvements in optimization and increasing clean product yield.
- Achieved industry-leading distillate yield of approximately 40 percent.
- Global refinery utilization rate of 93 percent in 2013, well above industry average.
- Expanded U.S. refined product export capability to 410,000 BPD by the end of 2013.

REFINING

U.S. REFINING AS OF DEC. 31, 2013



ASIA REFINING AS OF DEC. 31, 2013

EUROPE REFINING AS OF DEC. 31, 2013

WORLDWIDE REFINING AS OF DEC. 31, 2013

Region	Capacity (MBD)				Crude Mix (Percent)		Average Nelson Complexity Factor	Average Clean Product Yield (Percent)
	Crude[1]	Total	Gasoline[3]	Distillate[3]	Light/Medium	Heavy		
Western/Pacific[2]	440	488	210	205	45	55	11.6	85
Central Corridor[2]	485	531	265	185	60	40	11.1	87
Gulf Coast	733	855	340	355	65	35	12.2	82
Atlantic Basin/Europe[2]	588	657	270	285	85	15	9.0	83
Worldwide	2,246	2,531	1,085	1,030	65	35	11.0	84

[1] As of Jan. 1, 2014.
[2] Includes Phillips 66's share of joint-venture refineries.
[3] Clean product capacities are maximum rates for each clean product category, independent of each other. The capacities are not additive when calculating the average clean product yield.

KEY STRATEGIES

In 2013, Phillips 66 continued its strategy of aggressively pursuing increased access to advantaged crude oil to run in its refineries by expanding its own system capabilities and partnering with third-party transportation providers. Our 2013 U.S. refinery crude slate was 74 percent advantaged, compared with 62 percent in 2012. This increase was primarily due to processing 239,000 BPD of shale and similar tight oils, 118,000 BPD more than in 2012, as well as to additional domestic crudes consistently trading at a discount to Brent crude. Our Refining, Commercial and Transportation businesses work in collaboration to develop strategies for accessing advantaged crude with the goal of having our U.S. refineries capable of processing 100 percent advantaged crudes by the end of 2016.

By the end of 2013, we had 2,000 new railcars in service delivering primarily Bakken shale crude oil from North Dakota to our Bayway Refinery in New Jersey and our Ferndale Refinery in Washington. We are building new rail offloading facilities at these refineries that are expected to be operational in the second half of 2014. In early 2014, we ordered another 1,200 crude oil railcars that are expected to be delivered by the end of the year. We continue to use third-party logistics companies to deliver advantaged crude oil to our refineries and signed several new crude logistics agreements in 2013.

Phillips 66 is also making modest investments in its refineries to increase export capabilities and liquids yields. In 2013, we removed constraints at our coastal refineries to increase our total U.S. export capacity from 285,000 BPD in 2012 to 410,000 BPD. Over the next few years, we expect to achieve a clean product yield improvement of 1 percent with minimal capital investment. We are specifically focused on increasing yields of diesel because we expect global diesel demand to grow faster than gasoline demand. We already have an industry-leading distillate yield of about 40 percent and expect to achieve another 1 percent increase over the next few years.

REFINING

REFINING WESTERN/PACIFIC *as of Dec. 31, 2013*

Ferndale Refinery

101
CRUDE CAPACITY (MBD)

108
TOTAL CAPACITY (MBD)

55
GASOLINE CAPACITY (MBD)

30
DISTILLATE CAPACITY (MBD)

7.3
NELSON COMPLEXITY FACTOR

75%
CLEAN PRODUCT YIELD CAPABILITY

The Ferndale Refinery is located on Puget Sound in Ferndale, Washington, about 20 miles south of the U.S.-Canada border. The refinery processes Alaskan North Slope, sour Canadian and U.S. shale crude oils.

Ferndale operates a deepwater dock capable of accommodating tankers transporting Alaskan North Slope crude oil from Valdez, Alaska. It also receives Canadian crude oil via pipeline and U.S.-advantaged crude via a combination of rail and barge transport. Ferndale Refinery facilities include a fluid catalytic cracker, an alkylation unit, hydrotreating units and a naphtha reformer.

The refinery primarily produces transportation fuels, such as gasoline and diesel fuels. Other products include fuel oil supplying the northwest marine transportation market. Most refined products are distributed by pipeline and barge to major markets in the northwest United States. Recent improvements have enhanced the refinery's ability to export refined products.

In 2013, the necessary permits were received for a rail offloading facility that is expected to be operational in the second half of 2014. This facility will have capacity of 30,000 BPD and will enable the refinery to access additional advantaged crudes.

Los Angeles Refinery

139
CRUDE CAPACITY (MBD)

160
TOTAL CAPACITY (MBD)

80
GASOLINE CAPACITY (MBD)

65
DISTILLATE CAPACITY (MBD)

14.3
NELSON COMPLEXITY FACTOR

89%
CLEAN PRODUCT YIELD CAPABILITY

The Los Angeles Refinery is composed of two linked facilities located roughly five miles apart in Carson and Wilmington, California, about 15 miles southeast of Los Angeles International Airport. Carson serves as the front portion of the refinery by processing crude oil, and Wilmington serves as the back portion by upgrading the intermediate products to finished products.

The refinery processes mainly heavy, high-sulfur crude oil. It receives domestic crude oil via pipeline from California and both foreign and domestic crude oils by tanker through a third-party terminal in the Port of Long Beach. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels. Other products include fuel-grade petroleum coke.

The facilities include fluid catalytic cracking, alkylation, hydrocracking, coking and naphtha reforming units. The refinery produces California Air Resources Board (CARB)-grade gasoline and diesel fuels. Refined products are distributed to customers in California, Nevada and Arizona by pipeline and truck. Recent improvements have enhanced the refinery's ability to export refined products.

Phillips 66 is expanding its U.S. refined products export capability and expects to increase its export capacity to 550,000 BPD by the end of 2016.

San Francisco Refinery

120
CRUDE CAPACITY (MBD)

135
TOTAL CAPACITY (MBD)

55
GASOLINE CAPACITY (MBD)

60
DISTILLATE CAPACITY (MBD)

14.1
NELSON COMPLEXITY FACTOR

84%
CLEAN PRODUCT YIELD CAPABILITY

The San Francisco Refinery is comprised of two facilities linked by a 200-mile pipeline. The Santa Maria facility is located in Arroyo Grande, California, while the Rodeo facility is in the San Francisco Bay Area.

The refinery processes a mixture of heavy, high-sulfur and light sweet crude oils. It receives California crude oil via pipeline and both domestic and foreign crude oils by tanker. Semi-refined products from the Santa Maria facility are sent by pipeline to the Rodeo facility for upgrading into finished petroleum products. A large proportion of the refinery's production is transportation fuel, such as gasoline and diesel fuels.

Process facilities include coking, hydrocracking, hydrotreating and naphtha reforming units. The refinery produces CARB-grade gasoline and diesel fuels. The majority of refined products are distributed by pipeline, railcar and barge to customers in California. Recent improvements have enhanced the refinery's ability to export refined products.

Melaka Refinery[1]

80
CRUDE CAPACITY (MBD)

85
TOTAL CAPACITY (MBD)

20
GASOLINE CAPACITY (MBD)

50
DISTILLATE CAPACITY (MBD)

8.9
NELSON COMPLEXITY FACTOR

80%
CLEAN PRODUCT YIELD CAPABILITY

The PSR-2 refinery in Melaka, Malaysia, is a joint venture with Petronas, the Malaysian state oil company. Phillips 66 owns a 47 percent interest in the joint venture. The medium, high-sulfur crude oil processed by the refinery is sourced mostly from the Middle East.

The refinery produces a full range of refined petroleum products and capitalizes on hydrocracking and coking technology to upgrade low-cost feedstocks to higher-margin products. Phillips 66's share of refined products is transported by tanker and marketed in Malaysia and other Asian markets.

[1]Reflects Phillips 66's equity share.

REFINING

REFINING CENTRAL CORRIDOR *as of Dec. 31, 2013*

Billings Refinery

59
CRUDE CAPACITY (MBD)

65
TOTAL CAPACITY (MBD)

35
GASOLINE CAPACITY (MBD)

25
DISTILLATE CAPACITY (MBD)

14.0
NELSON COMPLEXITY FACTOR

89%
CLEAN PRODUCT YIELD CAPABILITY

The Billings Refinery, located in Billings, Montana, processes a mixture of Canadian heavy, high-sulfur crude oil plus domestic high-sulfur and low-sulfur crude oils, all delivered via pipeline and truck.

The facilities include fluid catalytic cracking, naphtha reforming and hydrodesulfurization units. A delayed coker converts heavy, high-sulfur residue into higher-value light oils. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels, as well as fuel-grade petroleum coke. Finished petroleum products from the refinery are delivered via pipeline, railcar and truck. Pipelines transport most of the refined products to markets in Montana, Wyoming, Idaho, Utah, Colorado and Washington.

Ponca City Refinery[1]

196
CRUDE CAPACITY (MBD)

210
TOTAL CAPACITY (MBD)

105
GASOLINE CAPACITY (MBD)

80
DISTILLATE CAPACITY (MBD)

9.4
NELSON COMPLEXITY FACTOR

92%
CLEAN PRODUCT YIELD CAPABILITY

The Ponca City Refinery, located in Ponca City, Oklahoma, processes a mixture of light, medium and heavy crude oils. Most of the crude oil processed is received by pipeline from Oklahoma, Texas and Canada. Recent and ongoing transportation infrastructure improvements have enabled the delivery of increased volumes of locally produced advantaged crude oil via pipeline and truck.

The Ponca City Refinery is a high-conversion facility that produces a full range of products, including gasoline, diesel and aviation fuels; liquefied petroleum gas (LPG); and anode-grade petroleum coke. Its facilities include two fluid catalytic cracking units, alkylation, delayed coking, naphtha reforming and hydrodesulfurization units. Finished petroleum products are shipped by truck, railcar, and pipelines to markets throughout the Midcontinent region.

[1] Crude capacity as of Jan. 1, 2014.

Our 2013 U.S. refinery crude slate was 74 percent advantaged, compared with 62 percent in 2012.

Borger Refinery[2]

73
CRUDE CAPACITY (MBD)

90
TOTAL CAPACITY (MBD)

50
GASOLINE CAPACITY (MBD)

25
DISTILLATE CAPACITY (MBD)

12.3
NELSON COMPLEXITY FACTOR

89%
CLEAN PRODUCT YIELD CAPABILITY

The Borger Refinery is located in Borger, Texas, in the Texas Panhandle about 50 miles north of Amarillo. Jointly owned by Phillips 66 and Cenovus Energy, the Borger Refinery is operated by Phillips 66. It includes an NGL fractionation facility with gross capacity of 45,000 BPD. The refinery primarily processes medium sour crude oil and NGL delivered through pipelines from West Texas, the Texas Panhandle, Wyoming and Canada.

The refinery facilities include two fluid catalytic cracking units, alkylation, delayed coking, hydrodesulfurization and naphtha reforming that enable it to produce a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels, as well as petroleum coke, NGL and solvents. Pipelines move refined products to West Texas, New Mexico, Colorado and the Midcontinent region.

Wood River Refinery[1, 2]

157
CRUDE CAPACITY (MBD)

166
TOTAL CAPACITY (MBD)

75
GASOLINE CAPACITY (MBD)

55
DISTILLATE CAPACITY (MBD)

11.8
NELSON COMPLEXITY FACTOR

83%
CLEAN PRODUCT YIELD CAPABILITY

The Wood River Refinery is located about 15 miles northeast of St. Louis, Missouri, in Roxana, Illinois. Jointly owned by Phillips 66 and Cenovus Energy, the Wood River Refinery is operated by Phillips 66. The complex includes a docking area on the Mississippi River. The refinery processes a mix of light, low-sulfur; heavy, high-sulfur; and high-acid crude oils. Wood River receives Canadian and domestic crude oils, including from U.S.-advantaged sources, and other foreign crude oil, by various pipelines. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels. Other products include petrochemical feedstocks, asphalt and coke.

Operations include two fluid catalytic cracking units, alkylation, hydrocracking, two delayed coking units, naphtha reforming, hydrotreating and sulfur recovery. Wood River is a major supplier to Lambert International Airport in St. Louis and Chicago O'Hare Airport. Finished product leaves Wood River through pipelines and by rail, barge and truck.

[1] Crude capacity as of Jan. 1, 2014. [2] Reflects Phillips 66's equity share.

REFINING

REFINING GULF COAST *as of Dec. 31, 2013*

Alliance Refinery

247
CRUDE CAPACITY (MBD)

275
TOTAL CAPACITY (MBD)

125
GASOLINE CAPACITY (MBD)

120
DISTILLATE CAPACITY (MBD)

11.9
NELSON COMPLEXITY FACTOR

87%
CLEAN PRODUCT YIELD CAPABILITY

The Alliance Refinery, located on the Mississippi River in Belle Chasse, Louisiana, 25 miles south of New Orleans, processes mainly light, low-sulfur crude oil. Alliance receives domestic crude oil from the Gulf of Mexico via pipeline and foreign crude oil from West Africa via pipeline connected to the Louisiana Offshore Oil Port. The refinery also receives U.S.-advantaged crude oil via marine transport.

The single-train refinery's facilities include fluid catalytic cracking, alkylation, coking, and hydrodesulfurization units, a naphtha reformer and aromatics units that enable it to produce a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels. Other products include petrochemical feedstocks, home heating oil and anode-grade petroleum coke.

The majority of the refined products are distributed to customers in the southeastern and eastern United States through major common-carrier pipeline systems and by barge. Recent improvements have enhanced the refinery's ability to export refined products, and Alliance now has the capability to export over 40 percent of its production.

Lake Charles Refinery

239
CRUDE CAPACITY (MBD)

280
TOTAL CAPACITY (MBD)

90
GASOLINE CAPACITY (MBD)

115
DISTILLATE CAPACITY (MBD)

11.3
NELSON COMPLEXITY FACTOR

70%
CLEAN PRODUCT YIELD CAPABILITY

The Lake Charles Refinery, located in Westlake, Louisiana, processes some light, sweet crude oil; however, it primarily processes heavy, high-sulfur and high-acid crude oils. The refinery receives domestic Gulf Coast, U.S.-advantaged and foreign crude oils.

The facilities include crude distillation, a fluid catalytic cracker, alkylation, a delayed coker and hydrodesulfurization units that enable it to produce gasoline and diesel fuels, home heating oil and fuel-grade petroleum coke. The refinery facilities also include a specialty coker and calciner, which produce graphite petroleum coke for the steel industry.

The Lake Charles Refinery produces a high percentage of transportation fuels, such as gasoline and aviation fuels, along with home heating oil. The majority of its refined products are distributed by truck, railcar, barge or major common-carrier pipelines in the southeastern and eastern United States. In addition, refined products can be sold into export markets through the refinery's marine terminal.

Sweeny Refinery

247
CRUDE CAPACITY (MBD)

300
TOTAL CAPACITY (MBD)

125
GASOLINE CAPACITY (MBD)

120
DISTILLATE CAPACITY (MBD)

13.2
NELSON COMPLEXITY FACTOR

87%
CLEAN PRODUCT YIELD CAPABILITY

The Sweeny Refinery, located in Old Ocean, Texas, 65 miles southwest of Houston, processes mainly heavy, high-sulfur crude oil, but also processes light, low-sulfur crude oil. The refinery receives U.S.-advantaged and foreign crude oil primarily through wholly and jointly owned terminals on the Gulf Coast, including a deepwater terminal at Freeport, Texas.

The refinery facilities include two fluid catalytic cracking units, delayed coking, alkylation, a naphtha reformer and hydrodesulfurization units. It operates nearby terminals and storage facilities in Freeport, Jones Creek and on the San Bernard River, along with pipelines that connect these facilities to the refinery.

The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels. Other products include petrochemical feedstocks, home heating oil and fuel-grade petroleum coke. Refined products are distributed throughout the midwest and southeastern United States by pipeline, barge and railcar. Recent improvements have enhanced the refinery's ability to export refined products.

REFINING

REFINING ATLANTIC BASIN/EUROPE *as of Dec. 31, 2013*

Bayway Refinery

238
CRUDE CAPACITY (MBD)

285
TOTAL CAPACITY (MBD)

145
GASOLINE CAPACITY (MBD)

115
DISTILLATE CAPACITY (MBD)

8.1
NELSON COMPLEXITY FACTOR

90%
CLEAN PRODUCT YIELD CAPABILITY

The Bayway Refinery, located on the New York Harbor in Linden, New Jersey, processes mainly light, low-sulfur crude oil. Crude oil is supplied to the refinery by tanker, primarily from the North Sea, Canada and West Africa. U.S.-advantaged crude oil is supplied to the refinery using a combination of rail and marine transport.

Bayway refining units include one of the world's largest fluid catalytic cracking units, hydrodesulfurization units, a naphtha reformer, an alkylation unit and other processing equipment.

The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels, as well as petrochemical feedstocks, residual fuel oil and home heating oil. The facility distributes refined products to East Coast customers via barges, trucks, pipelines and railcars. Bayway also has a 775 MMLb/Y polypropylene plant.

Construction began in 2013 on a rail offloading facility that is expected to be operational in the second half of 2014. This facility will have capacity of 70,000 BPD and will enable the refinery to access additional advantaged crudes.

Whitegate Refinery

71
CRUDE CAPACITY (MBD)

71
TOTAL CAPACITY (MBD)

15
GASOLINE CAPACITY (MBD)

30
DISTILLATE CAPACITY (MBD)

4.2
NELSON COMPLEXITY FACTOR

65%
CLEAN PRODUCT YIELD CAPABILITY

The Whitegate Refinery is located in Cork, Ireland. Whitegate is Ireland's only refinery processes light, low-sulfur crude oil sourced mostly from the North Sea, North Africa and West Africa.

Whitegate primarily produces transportation fuels, such as gasoline, diesel and fuel oil, that are distributed mostly inland, with some exported to international markets. Phillips 66 also operates a crude oil and products terminal with 7.5 million barrels of storage facilitated by an offshore mooring buoy in Bantry Bay, Cork, Ireland, which is about 80 miles southwest of the refinery.

Humber Refinery

221
CRUDE CAPACITY (MBD)

240
TOTAL CAPACITY (MBD)

85
GASOLINE CAPACITY (MBD)

115
DISTILLATE CAPACITY (MBD)

11.7
NELSON COMPLEXITY FACTOR

81%
CLEAN PRODUCT YIELD CAPABILITY

The Humber Refinery is located in North Lincolnshire, United Kingdom. Crude oil processed at the refinery is supplied primarily from the North Sea and includes light-, low- and medium-sulfur and acidic crude oils.

Humber is one of the most sophisticated refineries in Europe. It is a fully integrated facility that produces a large proportion of transportation fuels, such as gasoline, diesel and aviation fuels. Humber's fluid catalytic cracking unit/thermal cracking/coking configuration enables substantial volumes of other feedstocks, such as low-sulfur fuel oil and vacuum gas oil, to be processed alongside crude oil to fully utilize Humber's cracking capability.

The refinery has two coking units with associated calcining plants that upgrade the heavy bottoms and imported feedstocks into light oil products and high-value graphite and anode-grade petroleum coke. Humber, the only coking refinery in the United Kingdom, is the world's largest producer of specialty graphite cokes and Europe's largest anode-grade coke producer. Approximately 60 percent of the light oils produced in the refinery are marketed in the United Kingdom, while the other products are exported to the rest of Europe, West Africa and the United States.

MiRO Refinery[1]

58
CRUDE CAPACITY (MBD)

61
TOTAL CAPACITY (MBD)

25
GASOLINE CAPACITY (MBD)

25
DISTILLATE CAPACITY (MBD)

7.9
NELSON COMPLEXITY FACTOR

85%
CLEAN PRODUCT YIELD CAPABILITY

The Mineraloelraffinerie Oberrhein GmbH (MiRO) Refinery, located on the Rhine River in Karlsruhe in southwest Germany, is a joint venture refinery with Phillips 66 holding an 18.75 percent interest. The other owners are Shell, ExxonMobil and Ruhr Oel GmbH. Phillips 66 processes mainly medium sweet and medium sour crude oils in its share of the refinery. Crude is sourced from Russia, North Africa, the Caspian Sea and the Middle East and is delivered to the refinery via a cross-country pipeline from the port in Trieste, Italy.

The facilities at the high-conversion refinery include three crude unit trains, fluid catalytic cracking, petroleum coking and calcining, hydrodesulfurization units, naphtha reformers, isomerization and aromatics recovery units, ethyl tert-butyl ether, and alkylation units that enable it to produce a high percentage of transportation fuels, such as gasoline and diesel fuels. Other products include petrochemical feedstocks, home heating oil, bitumen, and anode and fuel-grade petroleum coke.

Phillips 66 distributes the majority of its share of the refined products to customers in southwest Germany, northern Switzerland and western Austria by truck, railcar, barge and pipeline.

[1]Reflects Phillips 66's equity share.

MARKETING AND SPECIALTIES

Phillips 66 packages finished lubricants at plants like this one in Hartford, Illinois.

Phillips 66's Marketing and Specialties segment includes marketing of gasoline, diesel and aviation fuel in the United States, as well as marketing of gasoline and diesel in Europe. The segment also includes the company's lubricants, specialty products and power generation businesses.

MARKETING AND SPECIALTIES OVERVIEW

OPERATING HIGHLIGHTS	2013	2012	2011
Marketing gasoline sales (MBD)	1,174	1,101	1,204
Marketing distillate sales (MBD)	967	985	1,039
Marketing petroleum product sales (MBD)	2,158	2,103	2,261
Combined total recordable rate (safety incidents per 200,000 hours)	0.17	0.20	0.13

2013 ACCOMPLISHMENTS

- Sold Immingham Combined Heat and Power Plant in the United Kingdom.
- Record volume of Group II base oil produced by 50-50 joint venture Excel Paralubes®.
- Expanded lubricants line with an energy-saving hydraulic oil and several products to enhance automotive fuel economy.
- Achieved record sales of Liquid Titanium® protection additive lubricant products.
- Announced the exchange of flow improvers business, Phillips Specialty Products Inc., for shares of Phillips 66 stock. The transaction closed in early 2014.

MARKETING AND SPECIALTIES

MARKETING

United States

In the United States, Phillips 66 markets gasoline, diesel and aviation fuel. Most marketing outlets are owned and operated by independent dealers and wholesale marketers. The majority of these outlets are branded Phillips 66®, Conoco® or 76® and feature gasolines that have been recognized as TOP TIER™ by leading automakers. These operations are strategically served by the company's refineries and transportation systems.

In its wholesale operations, Phillips 66 utilizes a network of branded marketers and dealers operating approximately 7,100 outlets. Refined products are sold on both a branded and unbranded basis. The company emphasizes the wholesale channel of trade; however, we also hold brand licensing agreements with approximately 600 other sites.

In addition to automotive gasoline and diesel fuel, the company produces aviation fuels and markets them through independent marketers and dealers at approximately 900 Phillips 66® aviation-branded, fixed-base operations, the largest branded network in the U.S. general aviation industry.

Europe

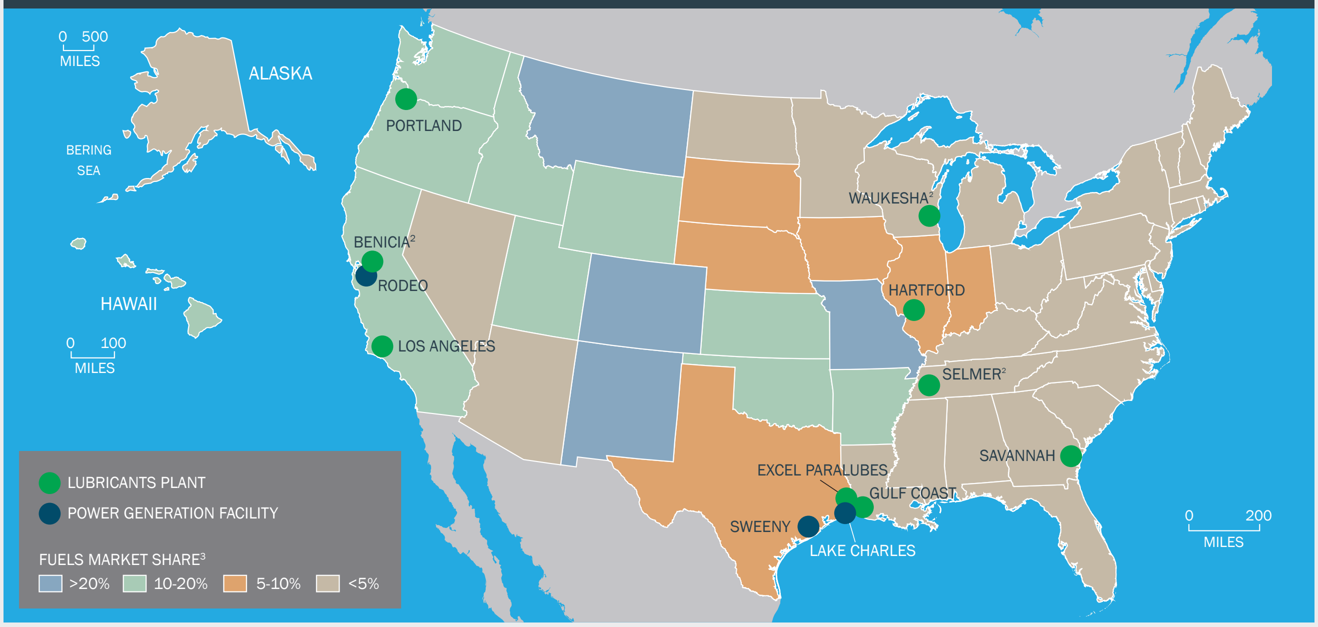
In Europe, Phillips 66 markets motor fuels under JET® through company-owned outlets in Germany and Austria and dealer-owned outlets in the United Kingdom. The company also has an equity interest in a joint venture that markets motor fuels in Switzerland under Coop®.

Phillips 66 markets aviation fuels, LPG, heating oils, transportation fuels, marine bunker fuels, fuel coke and bitumen to commercial customers and into the bulk or spot market. In addition, substantially all Whitegate Refinery production is sold to local and international oil companies and independent resellers in the inland Ireland market.

As of Dec. 31, 2013, Marketing and Specialties had approximately 1,440 marketing outlets in its European operations, of which approximately 925 were company owned and 315 were dealer owned. The company also held brand licensing agreements with approximately 200 sites. Additionally, through joint-venture operations in Switzerland, Phillips 66 has interests in 275 other sites. Over the next five years, the company expects to build approximately 200 new JET retail sites, mainly in Germany and Austria.

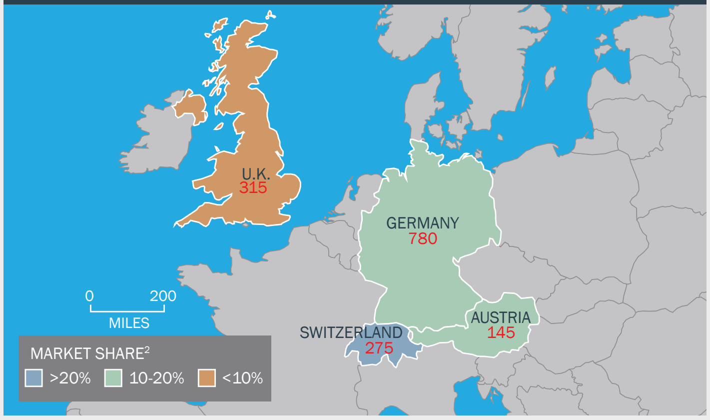
Phillips 66 markets fuels and lubricants under these brands

U.S. MARKETING AND SPECIALTIES[1] AS OF DEC. 31, 2013



[1] As Flow Improvers business was divested in early 2014, its assets are not shown.
[2] Lubricants plants included in Spectrum Corp. acquisition completed in the third quarter of 2014.
[3] Market share based on all Phillips 66 stations as a percentage of total stations in state.

EUROPE MARKETING[1] AS OF DEC. 31, 2013



[1] Map does not include 200 sites with brand licensing agreements.
[2] Market share based on sold fuel volumes.

MARKETING AND SPECIALTIES

POWER GENERATION

In the first quarter of 2014, Phillips 66 increased its ownership interest in the 440-megawatt Sweeny Cogeneration Power Plant to 100 percent by acquiring the remaining 50 percent interest. Phillips 66's Sweeny Refinery and CPChem's Sweeny facility both use steam and power generated by the plant. Excess power is sold into the power commodity market. Our Rodeo Carbon plant has a steam power plant that generates steam and power for on-site use with excess power for sale into the California market. Phillips 66 owns a 37 percent ownership interest in the Nelson Industrial Steam Company that consumes petroleum coke produced by the Lake Charles Refinery. Generated steam is sold to a third party and power is sold to the local utility. In July 2013, we sold the Immingham Combined Heat and Power Plant located in North Lincolnshire, United Kingdom.

SPECIALTIES BUSINESSES

Phillips 66 manufactures and markets specialty products, including petroleum coke products, waxes, solvents and polypropylene, which are sold to commercial, industrial and wholesale buyers worldwide.

Petroleum Coke

Phillips 66 is the largest global producer of needle coke for manufacturing electric arc furnace electrodes, supported by our outstanding manufacturing expertise, technological leadership and rigorous quality control. Our experience in carbon upgrading also supports the supply of green and calcined specialty cokes to the steel, aluminum and titanium dioxide industries in multiple countries from our refineries located in North America and the United Kingdom.

Calcined specialty coke is produced at the Lake Charles Refinery in Louisiana.

Solvents

At the Borger and Sweeny refineries, Phillips 66 manufactures and markets pure-grade specialty solvents, including pentanes, hexanes and heptanes, for use in a variety of industrial and chemical manufacturing applications. These products are marketed globally and used in the production of such products as vegetable oil, automotive tires, foam insulation and adhesives.

Polypropylene

Phillips 66 produces polypropylene resins at its world-scale polypropylene plant adjacent to its Bayway Refinery in Linden, New Jersey. The product is sold under COPYLENE®. The plant is one of the newest and largest polypropylene production units in the northeast United States, with a nameplate capacity of 775 MMLb/Y.

The Phillips 66 lubricants plant in Hartford, Illinois.

LUBRICANTS

Finished Lubricants

Phillips 66 is one of the largest finished lubricants suppliers in the United States. It manufactures and markets four major lubricant brands: Phillips 66®, Conoco®, 76® and Kendall®. The combination of these diverse brands, along with supplying a number of private-label and original-equipment manufacturers in North America, gives Phillips 66 a position in all key lubricants markets. The distribution network consists of marketers, mass merchandise stores, fast lube stores, tire stores and automotive dealers.

In line with the company's strategy to selectively grow its Marketing and Specialties business, Phillips 66 announced in the second quarter of 2014 its intention to acquire Spectrum Corporation, a leading specialty lubricants company. Spectrum is an independent blender, packager and marketer of specialty lubricants including two-cycle engine oil, small engine oil and hydraulic oil. It offers a broad array of private-label and brand-name specialty lubricants and related products, including more than 500 products under 14 separate product lines. The acquisition is expected to increase Phillips 66's access to specialized global lubricants markets and create new opportunities to expand its worldwide Lubricants customer base. The transaction closed in the third quarter of 2014.

Base Oil

The base oil marketing activities of Phillips 66 include the sale of Group II Pure Performance® hydrocracked base oils to an extensive list of customers throughout the world and the purchase of a wide range of base oils from several North American refiners that fulfill the manufacturing needs of the finished lubricants product lines. Base oils are manufactured at the 50-50 joint-venture Excel Paralubes plant in Westlake, Louisiana. Additionally, Phillips 66 has an exclusive agreement with South Korea's S-Oil Corporation to distribute and market their high-viscosity-index Group III Ultra-S® base oils in North America.

An employee at the Los Angeles lubricants plant inspects a product sample.

UNITS OF MEASURE

BCF	Billion cubic feet
BCFD	Billions of cubic feet per day
BLb/Y	Billions of pounds per year
BPD	Barrels per day
BTU	British thermal units
BTUD	British thermal units per day
Lb/MBbl	Pounds per thousand barrels
MBbls	Thousands of barrels
MBD	Thousands of barrels per day
MCFD	Thousands of cubic feet per day
MMBbl	Millions of barrels
MMBD	Millions of barrels per day
MMCFD	Millions of cubic feet per day
MMLb/Y	Millions of pounds per year
TBTU	Trillion British thermal units
TBtu/d	Trillion British thermal units per day

COMMONLY USED ABBREVIATIONS

NGL	Natural gas liquids
ROCE	Return on capital employed
LPG	Liquefied petroleum gas

DATA

Distillate capacity includes aviation fuels. The Nelson Complexity Factor calculation considers the variety and capacity of the different processing units within a refinery. The higher a refinery's factor, the greater its secondary conversion capacity and capability to produce higher-value products.

SAFE HARBOR STATEMENT

This Fact Book contains certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created thereby. Words and phrases such as “is anticipated,” “is estimated,” “is expected,” “is planned,” “is scheduled,” “is targeted,” “believes,” “intends,” “objectives,” “projects,” “strategies” and similar expressions are used to identify such forward-looking statements. However, the absence of these words does not mean that a statement is not forward-looking. Forward-looking statements relating to Phillips 66’s operations (including joint venture operations) are based on management’s expectations, estimates and projections about the company, its interests and the energy industry in general on the date this Fact Book was prepared. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecast in such forward-looking statements. Factors that could cause actual results or events to differ materially from those described in the forward-looking statements include fluctuations in crude oil, NGL, and natural gas prices, and refining and petrochemical margins; unexpected changes in costs for constructing, modifying or operating our facilities; unexpected difficulties in manufacturing, refining or transporting our products; lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, NGL, and refined products; potential liability from litigation or for remedial actions, including removal and reclamation obligations under environmental regulations; limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets; and other economic, business, competitive and/or regulatory factors affecting Phillips 66’s businesses generally as set forth in our filings with the Securities and Exchange Commission. Phillips 66 is under no obligation (and expressly disclaims any such obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

Phillips 66
P.O. Box 4428
Houston, TX 77210

www.phillips66.com

ABOUT PHILLIPS 66

Built on more than 130 years of experience, Phillips 66 is a growing energy manufacturing and logistics company with high-performing Midstream, Chemicals, Refining, and Marketing and Specialties businesses. This integrated portfolio enables Phillips 66 to capture opportunities in a changing energy landscape. Headquartered in Houston, the company has 13,500 employees who are committed to operating excellence and safety. Phillips 66 had $50 billion of assets as of Dec. 31, 2013. For more information, visit *www.phillips66.com* or follow us on Twitter *@Phillips66Co*.

CSH-14-0592

XPP

South Coast Air Quality Management District
Form 400-A
Application Form for Permit or Plan Approval
List only one piece of equipment or process per form.

AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): Phillips 66 Los Angeles Refinery, Carson Plant

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (•) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

1520 East Sepulveda Boulevard
Street Address
Carson, CA 90745
City, Zip
Knut Beruldsen — Env. Engineer
Contact Name, Title
(310) 952-6504
Phone #, Ext., Fax #
E-Mail: knut.j.beruldsen@p66.com

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

1660 West Anaheim Street
Address
Wilmington, CA 90744
City, State, Zip
Knut Beruldsen — Env. Engineer
Contact Name, Title
(310) 952-6504
Phone #, Ext., Fax #
E-Mail: knut.j.beruldsen@p66.com

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM ( ) In Title V (•) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- (•) New Construction (Permit to Construct) (10)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: ______

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy): 06/01/2013
8b. Estimated End Date of Construction (mm/dd/yyyy): 12/01/2015
8c. Estimated Start Date of Operation (mm/dd/yyyy): 12/01/2015

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): 575,000 BBL Crude Oil Storage Tank w/ 6 mixers - Tank 2640

10. For Identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 1

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (•) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (•) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? Oil Refinery

14. What is your business primary NAICS Code? (North American Industrial Classification System) 32411

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (•) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (•) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: Env. Superintendent

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (•) Yes

20. Print Name: Marshall Waller

21. Date: 10/25/12

22. Do you claim confidentiality of data? (If Yes, see instructions.) ( ) No (•) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
	544857	10105	$ 5,160.09	(105788)	11/21/12

DATE	APP REJ	DATE	APP REJ	CLASS	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN
				I III	10106	2,580.05	C		(105789)

10107 5,160.09 (105790) T3-15
10108 1,789.12 (105791)
10109 2,580.05 (105792)
10110 5,160.09 (105793)

248919

2/6

SCAQ[illegible]D PERMIT PROCESSING SYSTEM[illegible]PS)

FEE DATA - SUMMARY SHEET

Application No : 544857 — IRS/SS No:

Previous Application No: — Previous Permit No:

Company Name : PHILLIPS 66 COMPANY/LOS ANGELES REFINERY — Facility ID: 171109

Equipment Street: 1520 E SEPULVEDA BLVD , CARSON CA 90745

Equipment Desc : STORAGE TANK-GAS DOME EXT.FLOAT ROOF

Equipment Type : BASIC — Fee Charged by: B-CAT

B-CAT NO. : 248919 — C-CAT NO: 00 — Fee Schedule: C

Facility Zone : 04 — Deemed Compl. Date: 12/13/2012 — Public Notice: NO

Evaluation Type : PERMIT TO CONSTRUCT (PC) — Small Business: ☐

Disposition : Approve PC, Recommended by Engineer — Higher Fees for Failing to Obtain a Permit: ☐

Lead Appl. No :

Identical Permit Unit: ☒

Air quality Analysis			$0.00
E.I.R			$0.00
Health Risk Assessment			$0.00
Public Notice Preparation Fee			$0.00
Public Notice Publication Fee			$0.00
Expedited Processing	Hours:	0.00	$860.02
Source Test Review	Hours:	0.00	$0.00
Time & Material	Hours:	0.00	$0.00

Filing Fee Paid:	$0.00
Permit Processing Fee Paid:	$2,580.05
Permit Processing Fee Calculated*:	$1,720.03
Permit Processing Fee Adjustment:	$-860.02
Total Additional Fee:	$860.02
Additional Charge:	$0.00

COMMENTS:

RECOMMENDED BY: JANICE WEST — DATE: 09/04/2013

REVIEWED BY:__________________ — DATE:________________

* ADJUSTED FOR SMALL BUSINESS, IDENTICAL EQUIPMENT AND P/O NO P/C PENALTY

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Tuesday, September 03, 2013 2:05 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project

Our Crude buyer calls it AWB crude. It is from Canada. All three of the manifest cars were from the same supplier.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Tuesday, September 03, 2013 2:02 PM
To: Matthews, John W
Subject: [EXTERNAL]RE: RE: AI Request for crude tanks project

Sorry, I meant geographic origin or other identifier, (similar to California or San Joaquin Valley or Canada), just to identify that column as different and not an average of the others). (Danny was asking for an additional identifier)

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Tuesday, September 03, 2013 1:59 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project

The table was for the proposed crude tank. The crude speciation for the manifest cars was based on three discrete vapor samples taken directly from the representative manifest cars currently being received. The results of the individual samples are in the second, third and fourth columns. The labels on the top of those columns are the DOT numbers of the sampled railcars. The vapor samples were analyzed by EPA Method TO-15.

The maximum from these crude vapor samples (the fifth column) were used in the hybrid speciation.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Tuesday, September 03, 2013 11:25 AM
To: Matthews, John W
Subject: [EXTERNAL]FW: RE: AI Request for crude tanks project

Hi John,

In the attached table, there are columns for SJV crude, "crude oils", Cal crude, and crude hybrid. What is the origin of "crude oils"?

Janice

From: Marcia Baverman [mailto:mbaverman@envaudit.com]
Sent: Tuesday, February 05, 2013 1:58 PM
To: Matthews, John W (P66)

Cc: mchoi@envaudit.com
Subject: [EXTERNAL]RE: AI Request for crude tanks project

John –

Attached is the derivation of the "hybrid" speciation used to calculate the emissions in the EPA Tanks 4.0 model. The hybrid speciation is the highest concentration for each TAC from each of the three crude speciations used in the most recent AB2588 HRA. The hybrid speciation allows for only having to run one scenario to determine the TAC emissions for use in the HRA.

Thanks -

Marcia Baverman
Project Manager
714-632-8521 ext. 237
mbaverman@envaudit.com

Privacy Warning: The attachments corresponding to this e-mail may possess information that is owned by Environmental Audit, Inc., which is privileged and confidential. The documents contained herein are solely for the use of the above-named party. If you are not the person or entity mentioned above, then you are warned that any reproduction photocopying, disclosure, or acting in reliance on the information contained in this e-mail is prohibited. If you have mistakenly received this e-mail, please notify us as soon as possible. If you have received this transmission in error, please destroy the original transmission and its attachments without reading or saving in any manner.

From: Matthews, John W (P66) [mailto:John.Matthews@p66.com]
Sent: Tuesday, January 15, 2013 10:24 AM
To: 'MBaverman@EnvAudit.com'
Subject: FW: AI Request for crude tanks project

As discussed.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, January 10, 2013 1:49 PM
To: Matthews, John W (P66)
Subject: [EXTERNAL]AI Request for crude tanks project

Hi John,

As I mentioned on the phone, I am requesting additional information in support of your crude tanks applications Please provide the following information:

- Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics.
- The true vapor pressure limit you are willing to accept for the operation of these tanks (emissions will be recalculated)
- Fugitive counts for the existing crude tanks (and whether this project will cause any changes—if so, provide pre and post-project counts)
- Information on the impact of the project on the benzene stripper (particularly fugitive counts), and your justification for why an additional application is not needed for that permit unit.

Paul, Tran and I met with Jay yesterday, and after our discussion, Jay instructed me to consider the existing tanks as post-NSR tanks, based on the information in the files, as well as the presence of a throughput limit. I will be re-calculating the baseline emissions using the Tanks program (and the parameters specified in the original permit to operate application), so that the calculation method is the same for pre- and post-project emissions.

Please let me know if you have any comments or questions. I'll wait to proceed until I hear from you.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Tuesday, September 03, 2013 1:59 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project
Attachments: Speciation Data.pdf

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Thanks -

Marcia Baverman
Project Manager
714-632-8521 ext. 237
mbaverman@envaudit.com

From: Matthews, John W (P66) [mailto:John.Matthews@p66.com]
Sent: Tuesday, January 15, 2013 10:24 AM
To: 'MBaverman@EnvAudit.com'
Subject: FW: AI Request for crude tanks project

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Please let me know if you have any comments or questions. I'll wait to proceed until I hear from you.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Phillips 66 Company
Los Angeles Refinery - Carson Plant
Toxic Fugitive Emission Speciation for Rail Modification

CONSTITUENT	ACFX71711	PPRX28550	ACFX73301	MAXIMUM	PERCENT	MW	Concentration		Emission Rate
	PPB (V/V)	PPB (V/V)	PPB (V/V)	PPB (V/V)	% (V/V)	g/mole	g/l	Wt. %	#/hr.
1,2,4-Trimethylbenzene	ND	1800	ND	1800	0.0002%	120	9.6E-06	0.005%	6.3E-06
1,3,5-Trimethylbenzene	ND	980	ND	980	0.0001%	120	5.3E-06	0.003%	3.4E-06
2,2,4-Trimethyl Pentane	49000	4800	25000	49000	0.005%	114	2.5E-04	0.13%	1.6E-04
4-Ethyltoluene	ND	550	ND	550	0.00006%	120	2.9E-06	0.0016%	1.9E-06
Benzene	930000	32000	690000	930000	0.093%	78	3.2E-03	1.74%	2.1E-03
Butane	31000000	660000	21000000	31000000	3.1%	58	8.0E-02	43.1%	5.2E-02
Cyclohexane	1900000	65000	1500000	1900000	0.19%	84	7.1E-03	3.8%	4.7E-03
Ethylbenzene	ND	2400	ND	2400	0.0002%	106	1.1E-05	0.006%	7.4E-06
Heptane	1200000	79000	790000	1200000	0.12%	100	5.4E-03	2.9%	3.5E-03
Hexane	16000000	220000	9800000	16000000	1.6%	86	6.1E-02	33.0%	4.0E-02
Isobutane	4700000	190000	2900000	4700000	0.47%	58	1.2E-02	6.5%	7.9E-03
o-Xylene	ND	3300	ND	3300	0.0003%	106	1.6E-05	0.008%	1.0E-05
p/m-Xylene	ND	12000	ND	12000	0.0012%	106	5.7E-05	0.03%	3.7E-05
Propane	7800000	780000	5900000	7800000	0.78%	44	1.5E-02	8.2%	1.0E-02
Toluene	240000	20000	190000	240000	0.024%	92	9.9E-04	0.5%	6.4E-04
TOTALS							1.9E-01		1.2E-01
Fugitive Emissions (#/hr.)	1.2E-01						Total Xylenes		4.7E-05

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Friday, July 19, 2013 2:33 PM
To: Janice West
Subject: RE: PRVs in tank system

All of the relief valves are on sampling loops. If the block valve is open and the sampling valve is closed, the relief valve will return the material to the main process line if the set point is exceeded. None of them vent to atmosphere.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, July 18, 2013 10:53 AM
To: Matthews, John W
Subject: [EXTERNAL]PRVs in tank system

Hi John,

I have a question on the six PRVs associated with Tank 2640: are they connected to the vapor recovery system or fitted with rupture disks?

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Wednesday, July 17, 2013 12:25 PM
To: Janice West
Subject: FW: RE: leg size on Tank 2643

The legs for Tank 2643 are indeed 4" diameter.

From: Michael Choi [mailto:mchoi@envaudit.com]
Sent: Wednesday, July 17, 2013 12:24 PM
To: Matthews, John W; "Marcia Baverman"
Subject: [EXTERNAL]RE: leg size on Tank 2643

Yes. The emissions have been adjusted to reflect the 4" diameters.

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Wednesday, July 17, 2013 12:19 PM
To: 'Marcia Baverman' (mbaverman@envaudit.com)
Cc: 'mchoi@envaudit.com'
Subject: FW: leg size on Tank 2643

I assume the legs are still 4", correct?

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Wednesday, July 17, 2013 11:29 AM
To: Matthews, John W
Subject: [EXTERNAL]leg size on Tank 2643

Hi John,

I noticed that in the most recent CEQA revision, it appeared that TANKS calculations were done only for the standard 3" legs. Was there a change to the leg size for Tank 2643? The most recent info I was provided described 4" legs and had two TANKS runs: legs and legless.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Monday, July 15, 2013 7:04 AM
To: Janice West
Subject: RE: CEQA tank capacity

I was told that the 615,000 and 14,000 bbl capacities will be the values on the tank nameplates. I believe those are the values usually put on the permits to make it easier for inspectors to verify the tank description. Based on that information, those values should be used in the permit descriptions for Tanks 2640 and 2643, respectively.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Friday, July 12, 2013 4:31 PM
To: Matthews, John W
Subject: [EXTERNAL]RE: CEQA tank capacity

(btw, the water draw tank was also modified from 11,500 bbl to 14,000 bbl nominal capacity – but again with no change to working capacity). Should the equipment description be changed for this as well?

From: Janice West
Sent: Friday, July 12, 2013 4:29 PM
To: 'Matthews, John W'
Subject: CEQA tank capacity

Hi John,

I noted in the revised CEQA document that the Tank 2640 capacity is now listed as 615,000 bbl nominal capacity (it was previously listed as 575,000 bbl, and that is the number I've proposed in the permit equipment description).

The working capacity (on which the emissions are based) is still 500,000 bbl, so that isn't a concern, but is this a change that should also be made to the permit equipment description (615,000 bbl capacity)?

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Michael Choi [mchoi@envaudit.com]
Sent: Tuesday, June 18, 2013 1:07 PM
To: Janice West
Cc: John.Matthews@p66.com; environmentalauditinc.com, mbaverman
Subject: 2778 - P66 - Crude Oil Storage Capacity Project Fugitve Speciation
Attachments: speciations.pdf

Janice,

As discussed this morning, the fugitive emissions for the components are based on a hybrid speciation of vapor fractions from the existing crude and the Canadian crude speciations. The vapor fractions from the existing crude speciation are from the current AB2588 HRA. The vapor fractions for the Canadian crude were calculated using the following formula:

Vapor wt fraction of x = Liquid wt% / 100 / Liquid MW of x * Liquid MW of Crude * Vapor Pressure of x / Ambient Vapor Pressure * Vapor MW of x / Vapor MW of Crude

The hybrid speciation is a combination of the maximum value of each individual chemical regardless of phase or profile. For example, the hexane liquid wt% of the Canadian crude speciation was higher than the AB2588 value, however, the liquid wt% of the AB2588 speciation was higher than the Canadian crude value. Therefore the Canadian crude value was used for the hybrid liquid speciation (TANKS), and the AB2588 value was used for the hybrid vapor speciation (components). This method creates a very conservative speciation for both liquid and vapor phases. I have attached the speciation chart from the HRA for your convenience.

Please contact me if you have any further questions or comments.

Best Regards,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Crude Speciation

Exisitng Crude Speciation

Chemical	Crude Liquid Wt%	Crude Vapor Wt%
Benzene	0.14	2.83
PACs (Chrysene)	0.00	0.00
Cresol (mixed isomers)	0.00	0.00
Ethylbenzene	0.15	0.13
n-Hexane	0.89	38.55
Naphthalene	0.09	0.00
Phenol	0.00	0.00
Toluene	0.58	1.01
Xylene (mixed isomers)	0.94	0.19
Cumene	0.00	0.00
Cyclohexane	0.74	19.14
1,2,4-Trimethylbenzene	0.28	0.01

Canadian Crude Speciation

Component	wt% liquid	ppm liquid	Molecular Weight	Vapor Pressure (mm Hg)	Vapor Pressure (psi)	wt fraction vapor	wt % vapor
Benzene	0.12	1200.00	78.11	95.2	1.8408824	2.02E-04	0.0202
Ethylbenzene	0.041	410.00	106.17	9.53	0.1842816	6.90E-06	0.0007
Hexane	0.96	9600.00	86.18	150	2.90055	2.54E-03	0.2542
Toluene	0.23	2300.00	92.4	28.4	0.5491708	1.15E-04	0.0115
Xylene	0.207	2070.00	106.16	6.72	0.1299446	2.46E-05	0.0025

Hybrid Speciation

Chemical	Crude Liquid Wt%	Crude Vapor Wt%
Benzene	0.14	2.83
PACs (Chrysene)	0.00	0.00
Cresol (mixed isomers)	0.00	0.00
Ethylbenzene	0.15	0.13
n-Hexane	0.96	38.55
Naphthalene	0.09	0.00
Phenol	0.00	0.00
Toluene	0.58	1.01
Xylene (mixed isomers)	0.94	0.19
Cumene	0.00	0.00
Cyclohexane	0.74	19.14
1,2,4-Trimethylbenzene	0.28	0.01

Janice West

From:	Matthews, John W [John.Matthews@p66.com]
Sent:	Monday, June 03, 2013 10:21 AM
To:	Michael Krause
Cc:	Barbara Radlein; Janice West; Tran Vo; Marshall Waller; 'dstevens@envaudit.com'
Subject:	Letter Requesting Expedited CEQA Review and USEPA Region IX Draft Permit Review
Attachments:	CEQA Letter.pdf

Attached is the letter requested by Barbara Radlein to document Phillips 66 Company's desire to honor the verbal commitment made by Environmental Audit on our behalf for expedited review of the draft Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project.

As described in the attached letter, we are also requesting that the USEPA review of the draft Title V permit be expedited.

We appreciate the District's efforts to expedite the permitting process for this project. Delays have already impacted our 2013 capital expenditure budget for the Los Angeles Refinery. We and our consultant are dedicated to responding to your information needs and comments as quickly as possible.

If you need something regarding this project, do not hesitate to contact me directly.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

Phillips 66
Los Angeles Refinery - Carson Plant
1520 E. Sepulveda Blvd.
Carson, California 90745
P. O. Box 6206
Carson, California 90747
Telephone 310-522-9300
www.phillips66.com

Via e-mail Delivery

June 3, 2013

ATTN: Mike Krause, Program Supervisor
CEQA Section
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-0944

PHILLPS 66 COMPANY LOS ANGELES REFINERY CARSON PLANT -
CRUDE OIL STORAGE CAPACITY PROJECT
REQUEST FOR EXPEDITED CEQA REVIEW AND USEPA REGION IX PERMIT REVIEW

This letter is to confirm the prior verbal commitment made by our consultant, Environmental Audit, on our behalf with respect to the expedited CEQA review for the draft negative declaration for the referenced project. Phillips 66 Company previously requested expedited review of the permit applications pertaining to the referenced project by submitting SCAQMD form 400-XPP with A/Ns: 544858 – 544861.

The initial draft negative declaration was submitted on November 28, 2012, and the current revised version was submitted in March of 2013. Phillips 66 Company requests that SCAQMD expedite the CEQA review in accordance with SCAQMD Rule 301(u)(2).

In addition to requesting expedited review for the draft negative declaration and the permit application, Phillips 66 requests expedited review by USEPA Region IX for the draft permit.

The information contained in this letter is considered confidential business information. If there are any questions, please contact Marshall Waller at (310) 952-6120 or John Matthews at (310) 952-6213.

Sincerely,

Marshall G. Waller
Environmental Superintendent

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Friday, May 24, 2013 12:31 PM
To: Janice West
Subject: RE: existing tank seals
Attachments: draft permit _crude tanks P66 Comments.doc

I have redlined the draft permit based on the best available information from the design team. Please see the attachment.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

rom: Janice West [mailto:jwest@aqmd.gov]
Sent: Tuesday, May 21, 2013 5:02 PM
To: Matthews, John W
Subject: [EXTERNAL]existing tank seals

Hi John,

I reviewed the tank seals with Paul, and since BACT is not required for the modified tanks, no seal upgrade is necessary. See below revised draft descriptions.

ORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-510, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 F
:IGHT: 50 FT WITH
N: ~~535286~~ 544860

DOME COVER, GEODESIC

FLOATING ROOF, PONTOON~~, WELDED SHELL~~

MARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE

SECONDARY SEAL, SHOE MOUNTED, CATEGORY B OR BETTER, WIPER TYPE

GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED

ORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-511, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 F
:IGHT: 50 FT WITH
N: ~~535287~~ 544861

DOME COVER, GEODESIC

FLOATING ROOF, PONTOON

PRIMARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE

SECONDARY SEAL, SHOE MOUNTED, CATEGORY B OR BETTER, WIPER TYPE

GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Tuesday, May 21, 2013 9:16 AM
To: Janice West
Subject: RE: crude analyses

Attached is a comparison of the results of the Canadian Crude Speciation vs. the speciation used in the submitted calculations. Only n-hexane was detected at a slightly higher concentration. There will be no significant impact on the HRA results, but we will be submitting revised calculations based on the higher n-hexane concentration no later than tomorrow.

The results seam to confirm our position that the speciation that was used is reasonably conservative.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, May 16, 2013 10:44 AM
To: Matthews, John W
Subject: [EXTERNAL]crude analyses

Hi John,

I told Paul about your plans, and he mentioned that if you currently have other types of crude on hand, a more recent analysis of a non-Canadian crude (in addition to your planned analysis) would provide a better comparison of the relative HAP concentration of your crude slate. Either refuting or confirming the claim that Canadian crudes have more HAPs. Since you're doing analyses anyway...

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Equipment	ID No.	Conn To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 10 : STORAGE TANKS					P13.2
System 7 : DOMED EXTERNAL FLOATING ROOF TANKS					
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. 2640, CRUDE OIL, WELDED SHELL WITH FOUR MIXERS, 563593 BBL; DIAMETER: 260 FT; HEIGHT: 65 FT WITH A/N: 544857 DOME COVER, GEODESIC FLOATING ROOF, PONTOON PRIMARY SEAL, CATEGORY A METALLIC SHOE SECONDARY SEAL, CATEGORY A, RIM MOUNTED GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	Dccc			HAP: (10) [40CFR 63 Subpart CC, #3A, 6-23-2003]	C1.xb, E193.x, H23.17
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. 2643, CRUDE/WATER, WELDED SHELL, 12069 BBL; DIAMETER: 44 FT; HEIGHT: 51 FT 7 IN WITH A/N: 544859 DOME COVER, GEODESIC FLOATING ROOF, DOUBLE DECK PRIMARY SEAL, CATEGORY A METALLIC SHOE SECONDARY SEAL, CATEGORY A, RIM MOUNTED GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	Dddd			HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]	C1.xc, E193.x, H23.17
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-510, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 FT; HEIGHT: 50 FT WITH A/N: ~~535286~~ 544860 DOME COVER, GEODESIC FLOATING ROOF, PONTOON~~, WELDED SHELL~~ PRIMARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE SECONDARY SEAL, SHOE MOUNTED, CATEGORY B OR BETTER, WIPER TYPE GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	D394			HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]	C1.xa, ~~C1.17,~~ E193.x, H23.4
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-511, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 FT; HEIGHT: 50 FT WITH	D395			HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]	C1.xa, ~~C1.17,~~ E193.x, H23.4

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Equipment	ID No.	Conn To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
A/N: ~~535287~~ 544861 DOME COVER, GEODESIC FLOATING ROOF, PONTOON PRIMARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE SECONDARY SEAL, SHOE MOUNTED, CATEGORY B OR BETTER, WIPER TYPE					
GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED					

Deleted: A, SHOE MOUNTED

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CONDITIONS

PROCESS CONDITIONS

P13.2 All devices under this process are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
Benzene	40CFR61, SUBPART	FF

[40CFR 61 Subpart FF, 12-4-2003]

[Processes subject to this condition : 1, 2, 3, 4, 5, 6, 7, 8, 9, 10]

SYSTEM CONDITIONS

DEVICE CONDITIONS

~~C1.17 The operator shall limit the throughput to no more than 4.5625e+06 barrel(s) in any one year.~~

~~[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]~~

~~[Devices subject to this condition : D394, D395]~~

C1.xa The operator shall limit the throughput to no more than 1.52 e+06 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D394, D395]

C1.xb The operator shall limit the throughput to no more than 2.5 e+06 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dccc]

C1.xc The operator shall limit the throughput to no more than 64,000 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dddd]

E193.x The operator shall install this equipment according to the following specifications:

The operator shall not use this equipment with materials having a Reid vapor pressure of 11 psia or greater.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dccc, Dddd, D394, D395]

H23.4 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1149
VOC	40CFR60, SUBPART	K

[RULE 1149, 7-14-1995; RULE 1149, 5-2-2008; **40CFR 60 Subpart K, 10-17-2000]**

[Devices subject to this condition : D394, D395, D396, D397]

H23.17 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1149
VOC	40CFR60, SUBPART	Kb

[RULE 1149, 7-14-1995; RULE 1149, 5-2-2008; **40CFR 60 Subpart Kb, 10-15-2003]**

[Devices subject to this condition : Dccc, Dddd]

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Thursday, May 23, 2013 1:46 PM
To: Janice West
Subject: FW: 2778 - Canadian Crude 1401 Revisions
Attachments: 2778 - Canadian Crude Emissions Tables.pdf; T2643 - Rule1401_Excel2007_Sep1010.pdf; T2640 - Rule1401_Excel2007_Sep1010.pdf; T511 - Rule1401_Excel2007_Sep1010.pdf; T510 - Rule1401_Excel2007_Sep1010.pdf

Attached are the modified calculations reflecting the minor increase in n-hexane liquid concentration from 0.89 to 0.96 wt %.

From: Michael Choi [mailto:mchoi@envaudit.com]
Sent: Thursday, May 23, 2013 1:34 PM
To: Matthews, John W
Cc: 'Marcia Baverman'
Subject: [EXTERNAL]2778 - Canadian Crude 1401 Revisions

John,

Attached are the calculations and Rule 1401 analyses for the tanks for the Crude Capacity Project. I am currently working through Archimedes' comments and will forward the results when I complete the review.

Please contact me if you have any further questions or comments.

Best Regards,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Crude Speciation

Exisitng Crude Speciation

Chemical	Crude Liquid Wt%	Crude Vapor Wt%
Benzene	0.14	2.83
PACs (Chrysene)	0.00	0.00
Cresol (mixed isomers)	0.00	0.00
Ethylbenzene	0.15	0.13
n-Hexane	0.89	38.55
Naphthalene	0.09	0.00
Phenol	0.00	0.00
Toluene	0.58	1.01
Xylene (mixed isomers)	0.94	0.19
Cumene	0.00	0.00
Cyclohexane	0.74	19.14
1,2,4-Trimethylbenzene	0.28	0.01

Canadian Crude Speciation

Component	wt% liquid	ppm liquid	Molecular Weight	Vapor Pressure (mm Hg)	Vapor Pressure (psi)	wt fraction vapor	wt % vapor
Benzene	1.20E-01	1200.00	78.11	95.2	1.8408824	2.02E-04	2.02E-02
Ethylbenzene	4.10E-02	410.00	106.17	9.53	0.1842816	6.90E-06	6.90E-04
Hexane	9.60E-01	9600.00	86.18	150	2.90055	2.54E-03	2.54E-01
Toluene	2.30E-01	2300.00	92.4	28.4	0.5491708	1.15E-04	1.15E-02
Xylene	2.07E-01	2070.00	106.16	6.72	0.1299446	2.46E-05	2.46E-03

Hybrid Speciation

Chemical	Crude Liquid Wt%	Crude Vapor Wt%
Benzene	0.14	2.83
PACs (Chrysene)	0.00	0.00
Cresol (mixed isomers)	0.00	0.00
Ethylbenzene	0.15	0.13
n-Hexane	0.96	38.55
Naphthalene	0.09	0.00
Phenol	0.00	0.00
Toluene	0.58	1.01
Xylene (mixed isomers)	0.94	0.19
Cumene	0.00	0.00
Cyclohexane	0.74	19.14
1,2,4-Trimethylbenzene	0.28	0.01

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Fugitive Component Emissions

		Tank 2640			Tank 2643		
Chemical	Crude Vapor Wt%	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	2.83	7.44E+01	0.20	8.50E-03	19.33	0.05	2.21E-03
PACs (Chrysene)	0.00	3.56E-05	0.00	4.06E-09	9.24E-06	0.00	1.06E-09
Cresol (mixed isomers)	0.00	4.28E-05	0.00	4.89E-09	1.11E-05	0.00	1.27E-09
Ethylbenzene	0.13	3.29E+00	0.01	3.76E-04	8.55E-01	0.00	9.76E-05
n-Hexane	38.55	1012.95	2.78	1.16E-01	262.96	0.72	3.00E-02
Naphthalene	0.00	2.26E-02	0.00	2.58E-06	5.87E-03	0.00	6.71E-07
Phenol	0.00	1.02E-04	0.00	1.16E-08	2.64E-05	0.00	3.01E-09
Toluene	1.01	2.66E+01	0.07	3.04E-03	6.90	0.02	7.88E-04
Xylene (mixed isomers)	0.19	5.09E+00	0.01	5.81E-04	1.32E+00	0.00	1.51E-04
Cumene	0.00	7.03E-03	0.00	8.02E-07	0.00	0.00	2.08E-07
Cyclohexane	19.14	503.08	1.38	5.74E-02	130.60	0.36	1.49E-02
1,2,4-Trimethylbenzene	0.01	3.28E-01	0.00	3.74E-05	8.51E-02	0.00	9.71E-06
Total VOC	100.00	2.63E+03	7.20	3.00E-01	682.18	1.87	7.79E-02

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Tank Working Loss Emissions

	Tank 2640[1]			Tank 2643[1]			Tank R510/R511		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	8.28	0.0227	9.45E-04	1.66	0.0045	1.89E-04	6.96	0.0191	7.945E-04
PACs (Chrysene)	0.09	0.0002	1.03E-05	0.01	0.0000	1.14E-06	0.07	0.0002	7.991E-06
Cresol (mixed isomers)	0.03	0.0001	3.42E-06	-	-	0.00E+00	0.02	0.0001	2.283E-06
Ethylbenzene	7.10	0.0194	8.10E-04	1.11	0.0030	1.27E-04	5.17	0.0142	5.902E-04
n-Hexane	63.43	0.1738	7.24E-03	13.97	0.0383	1.59E-03	56.90	0.1559	6.495E-03
Naphthalene	4.24	0.0116	4.84E-04	0.64	0.0018	7.31E-05	3.03	0.0083	3.459E-04
Phenol	0.01	0.0000	1.14E-06	-	-	0.00E+00	0.01	0.0000	1.142E-06
Toluene	28.79	0.0789	3.29E-03	4.83	0.0132	5.51E-04	21.79	0.0597	2.487E-03
Xylene (mixed isomers)	44.70	0.1225	5.10E-03	6.98	0.0191	7.96E-04	32.47	0.0890	3.707E-03
Cumene	0.12	0.0003	1.37E-05	0.02	0.0001	2.28E-06	0.08	0.0002	9.132E-06
Cyclohexane	42.75	0.1171	4.88E-03	8.42	0.0231	9.61E-04	35.69	0.0978	4.074E-03
1,2,4-Trimethylbenzene	13.09	0.0359	1.49E-03	2.00	0.0055	2.29E-04	9.39	0.0257	1.072E-03
Total VOC	6,634.36	18.1763	7.57E-01	1,465.21	4.0143	1.67E-01	5963.21	16.3376	6.807E-01

(1) Tank leg emissions scaled for 4" legs.

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Total Tank Operational Emissions

	Tank 2640			Tank 2643		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	82.72	0.2266	0.0094	20.98	0.0575	0.0024
PACs (Chrysene)	0.09	0.0002	0.0000	0.01	0.0000	0.0000
Cresol (mixed isomers)	0.03	0.0001	0.0000	0.00	0.0000	0.0000
Ethylbenzene	10.39	0.0285	0.0012	1.96	0.0054	0.0002
n-Hexane	1,076.38	2.9490	0.1229	276.93	0.7587	0.0316
Naphthalene	4.26	0.0117	0.0005	0.65	0.0018	0.0001
Phenol	0.01	0.0000	0.0000	0.00	0.0000	0.0000
Toluene	55.38	0.1517	0.0063	11.73	0.0321	0.0013
Xylene (mixed isomers)	49.79	0.1364	0.0057	8.30	0.0227	0.0009
Cumene	0.13	0.0003	0.0000	0.02	0.0001	0.0000
Cyclohexane	545.83	1.4954	0.0623	139.02	0.3809	0.0159
1,2,4-Trimethylbenzene	13.42	0.0368	0.0015	2.09	0.0057	0.0002
Total VOC	9,262.19	25.3759	1.0573	2,147.39	5.8833	0.2451

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2643
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	48	feet
Area (For Volume Source Only)	3000	ft^2
Distance-Residential	700	meters
Distance-Commercial	125	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (NO = Tier 1 or Tier 2; YES = Tier 3)	NO

ission Units	lb/hr	
rce output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	2.40E-03	78.11	0.002395315		0.002395315
P15	Chrysene	1.14E-06	228.2928	1.14261E-06		1.14261E-06
C30	Cresol mixtures	1.27E-09	108.14	1.26964E-09		1.26964E-09
E4	Ethyl benzene	2.24E-04	106.16	0.000224312		0.000224312
H8	Hexane (n-)	3.16E-02	86.18	0.03161295		0.03161295
P30	Naphthalene	7.37E-05	128.1732	7.37299E-05		7.37299E-05
P3	Phenol	3.01E-09	94.11	3.00957E-09		3.00957E-09
T3	Toluene (methyl benzene)	1.34E-03	92.13	0.001339019		0.001339019
X1	Xylenes (isomers and mixtures)	9.47E-04	106.2	0.000947268		0.000947268
				0		
				0		
				0		
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				0		

TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: T2643
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors table:

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.282	16.48
Commercial	4.8075	180

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	2.40E-03	2.40E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	1.14E-06	1.14E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	1.27E-09	1.27E-09		1	1	1	1.0000	600	
Ethyl benzene	2.24E-04	2.24E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	3.16E-02	3.16E-02		1.0000	1.0000	1	1	7000	
Naphthalene	7.37E-05	7.37E-05	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	3.01E-09	3.01E-09		1	1	1	1	200	5800
Toluene (methyl benzene)	1.34E-03	1.34E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	9.47E-04	9.47E-04		1.0000	1.0000	1	1	700	22000

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	2.40E-03	2.40E-03	20.9254723	0.010462736
Chrysene	1.14E-06	1.14E-06	0.00998182	4.99091E-06
Cresol mixtures	1.27E-09	1.27E-09	1.1092E-05	5.5458E-09
Ethyl benzene	2.24E-04	2.24E-04	1.95959053	0.000979795
Hexane (n-)	3.16E-02	3.16E-02	276.170733	0.138085367
Naphthalene	7.37E-05	7.37E-05	0.64410439	0.000322052
Phenol	3.01E-09	3.01E-09	2.6292E-05	1.31458E-08
Toluene (methyl benzene)	1.34E-03	1.34E-03	11.6976695	0.005848835
Xylenes (isomers and mixtures)	9.47E-04	9.47E-04	8.27533062	0.004137665
Total	3.66E-02	3.66E-02	3.20E+02	1.60E-01

A/N: T2643

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	8.47E-08	2.82E-07
Chrysene	4.69E-10	7.67E-10
Cresol mixtures		
Ethyl benzene	6.90E-10	2.30E-09
Hexane (n-)		
Naphthalene	3.13E-09	1.04E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**8.90E-08**	**2.95E-07**
	PASS	**PASS**

No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		2.33E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.13E-10	Pass	Pass
Developmental - DEV	3.38E-04	9.25E-04	Pass	Pass
Endocrine system - END		2.33E-06	Pass	Pass
Eye	1.43E-05		Pass	Pass
Hematopoietic system - HEM	3.32E-04	8.30E-04	Pass	Pass
Immune system - IMM	3.32E-04		Pass	Pass
Kidney - KID		2.33E-06	Pass	Pass
Nervous system - NS	6.51E-06	1.04E-03	Pass	Pass
Reproductive system - REP	3.38E-04		Pass	Pass
Respiratory system - RES	1.43E-05	2.91E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2643 | Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			3.04E-05		3.04E-05	3.04E-05		3.04E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				8.55E-12					8.55E-12	
Toluene (methyl benzene)			5.96E-07	5.96E-07			5.96E-07	5.96E-07	5.96E-07	
Xylenes (isomers and mixtures)				7.10E-07					7.10E-07	
Total			3.10E-05	1.31E-06	3.04E-05	3.04E-05	5.96E-07	3.10E-05	1.31E-06	

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			3.32E-04		3.32E-04	3.32E-04		3.32E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				9.34E-11					9.34E-11	
Toluene (methyl benzene)			6.51E-06	6.51E-06			6.51E-06	6.51E-06	6.51E-06	
Xylenes (isomers and mixtures)				7.75E-06					7.75E-06	
Total			3.38E-04	1.43E-05	3.32E-04	3.32E-04	6.51E-06	3.38E-04	1.43E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Compound	HIC - Residential												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				4.87E-05			4.87E-05			4.87E-05			
Chrysene													
Cresol mixtures										2.58E-12			
Ethyl benzene	1.37E-07			1.37E-07	1.37E-07				1.37E-07				
Hexane (n-)										5.51E-06			
Naphthalene												9.99E-06	
Phenol	1.84E-11		1.84E-11						1.84E-11	1.84E-11			
Toluene (methyl benzene)				5.44E-06						5.44E-06		5.44E-06	
Xylenes (isomers and mixtures)										1.65E-06		1.65E-06	
Total	1.37E-07		1.84E-11	5.43E-05	1.37E-07		4.87E-05		1.37E-07	6.13E-05		1.71E-05	

A/N: T2643 **Application deemed complete date:** 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				8.30E-04			8.30E-04			8.30E-04			
Chrysene													
Cresol mixtures										4.40E-11			
Ethyl benzene	2.33E-06			2.33E-06	2.33E-06				2.33E-06				
Hexane (n-)										9.39E-05			
Naphthalene												1.70E-04	
Phenol	3.13E-10		3.13E-10						3.13E-10	3.13E-10			
Toluene (methyl benzene)				9.28E-05						9.28E-05		9.28E-05	
Xylenes (isomers and mixtures)										2.81E-05		2.81E-05	
Total	2.33E-06		3.13E-10	9.25E-04	2.33E-06		8.30E-04		2.33E-06	1.04E-03		2.91E-04	

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2640
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	64	feet
Area (For Volume Source Only)	53100	ft^2
Distance-Residential	750	meters
Distance-Commercial	175	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (NO = Tier 1 or Tier 2; YES = Tier 3)	NO

ission Units	lb/hr	
rce output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	9.44E-03	78.11	0.009443282		0.009443282
P15	Chrysene	1.03E-05	228.2928	1.0278E-05		1.0278E-05
C30	Cresol mixtures	3.43E-06	108.14	3.42955E-06		3.42955E-06
E4	Ethyl benzene	1.19E-03	106.16	0.001186084		0.001186084
H8	Hexane (n-)	1.23E-01	86.18	0.122874559		0.122874559
P30	Naphthalene	4.87E-04	128.1732	0.000486601		0.000486601
P3	Phenol	1.15E-06	94.11	1.15315E-06		1.15315E-06
T3	Toluene (methyl benzene)	6.32E-03	92.13	0.006321705		0.006321705
X1	Xylenes (isomers and mixtures)	5.68E-03	106.2	0.005683806		0.005683806
				0		
				0		
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				0		
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: T2640
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors table:

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.25	13.3
Commercial	2.6475	80.25

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	9.44E-03	9.44E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	1.03E-05	1.03E-05	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	3.43E-06	3.43E-06		1	1	1	1.0000	600	
Ethyl benzene	1.19E-03	1.19E-03	8.70E-03	1	1	1	1	2000	
Hexane (n-)	1.23E-01	1.23E-01		1.0000	1.0000	1	1	7000	
Naphthalene	4.87E-04	4.87E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.15E-06	1.15E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	6.32E-03	6.32E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	5.68E-03	5.68E-03		1.0000	1.0000	1	1	700	22000

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	9.44E-03	9.44E-03	82.4965153	0.041248258
Chrysene	1.03E-05	1.03E-05	0.08978893	4.48945E-05
Cresol mixtures	3.43E-06	3.43E-06	0.02996053	1.49803E-05
Ethyl benzene	1.19E-03	1.19E-03	10.3616316	0.005180816
Hexane (n-)	1.23E-01	1.23E-01	1073.43215	0.536716074
Naphthalene	4.87E-04	4.87E-04	4.25094833	0.002125474
Phenol	1.15E-06	1.15E-06	0.01007388	5.03694E-06
Toluene (methyl benzene)	6.32E-03	6.32E-03	55.2264119	0.027613206
Xylenes (isomers and mixtures)	5.68E-03	5.68E-03	49.653725	0.024826863
Total	1.46E-01	1.46E-01	1.28E+03	6.38E-01

A/N: T2640

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.96E-07	6.12E-07
Chrysene	3.74E-09	3.80E-09
Cresol mixtures		
Ethyl benzene	3.23E-09	6.69E-09
Hexane (n-)		
Naphthalene	1.83E-08	3.79E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**3.21E-07**	**6.60E-07**
	PASS	**PASS**

No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		6.86E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		6.60E-08	Pass	Pass
Developmental - DEV	5.97E-04	2.05E-03	Pass	Pass
Endocrine system - END		6.79E-06	Pass	Pass
Eye	3.45E-05		Pass	Pass
Hematopoietic system - HEM	5.83E-04	1.80E-03	Pass	Pass
Immune system - IMM	5.83E-04		Pass	Pass
Kidney - KID		6.86E-06	Pass	Pass
Nervous system - NS	1.37E-05	2.34E-03	Pass	Pass
Reproductive system - REP	5.97E-04		Pass	Pass
Respiratory system - RES	3.45E-05	9.53E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2640 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			9.66E-05		9.66E-05	9.66E-05		9.66E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				2.64E-09					2.64E-09	
Toluene (methyl benzene)			2.27E-06	2.27E-06			2.27E-06	2.27E-06	2.27E-06	
Xylenes (isomers and mixtures)				3.44E-06					3.44E-06	
Total			9.89E-05	5.71E-06	9.66E-05	9.66E-05	2.27E-06	9.89E-05	5.71E-06	

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			5.83E-04		5.83E-04	5.83E-04		5.83E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				1.60E-08					1.60E-08	
Toluene (methyl benzene)			1.37E-05	1.37E-05			1.37E-05	1.37E-05	1.37E-05	
Xylenes (isomers and mixtures)				2.07E-05					2.07E-05	
Total			5.97E-04	3.45E-05	5.83E-04	5.83E-04	1.37E-05	5.97E-04	3.45E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.70E-04			1.70E-04			1.70E-04			
Chrysene													
Cresol mixtures										6.18E-09			
Ethyl benzene	6.41E-07			6.41E-07	6.41E-07				6.41E-07				
Hexane (n-)										1.90E-05			
Naphthalene												5.85E-05	
Phenol	6.23E-09		6.23E-09						6.23E-09	6.23E-09			
Toluene (methyl benzene)				2.28E-05						2.28E-05		2.28E-05	
Xylenes (isomers and mixtures)										8.78E-06		8.78E-06	
Total	6.47E-07		6.23E-09	1.94E-04	6.41E-07		1.70E-04		6.47E-07	2.21E-04		9.00E-05	

6b. Hazard Index Chronic (cont.)

A/N: T2640 **Application deemed complete date:** 09/10/10

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.80E-03			1.80E-03			1.80E-03			
Chrysene													
Cresol mixtures										6.54E-08			
Ethyl benzene	6.79E-06			6.79E-06	6.79E-06				6.79E-06				
Hexane (n-)										2.01E-04			
Naphthalene												6.19E-04	
Phenol	6.60E-08		6.60E-08						6.60E-08	6.60E-08			
Toluene (methyl benzene)				2.41E-04						2.41E-04		2.41E-04	
Xylenes (isomers and mixtures)										9.30E-05		9.30E-05	
Total	6.86E-06		6.60E-08	2.05E-03	6.79E-06		1.80E-03		6.86E-06	2.34E-03		9.53E-04	

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Thursday, May 23, 2013 1:01 PM
To: Janice West
Subject: FW: Bellows Seal Valves

Below is the rationale for the non-bellow seal valves from the design engineering team. If there is a discrepancy in the count, the paragraph below states that (3) bellow sealed 24" valves were replaced with (2) 30" gate valves on proposed Tank 2640.

John – please see the requested information below. Sorry for the delay – I was out all day yesterday with a doctor's appointment.

Please note, the prior email mentioned 56 exempt valves, but the total now is really 58. In the prior email below the "last fugitive count" I referred to did not include (2) 30" exempt valves (EX4) based on a final decision that had been made recently to go from (3) 24" gate valves on the inlet to the new tank (which would have been bellows seal valves), to the (2) 30" gate valves which then become EX4 exempt. This change was made based on an independent decision related to minimum heel, and nothing to do with exemption status.

Service	Exemption	No. of Valves
HC Gas/Vapor	EX1 – Safety	2
Lt Liquid	EX1 – Safety	36
Lt Liquid	EX3 – Torsional	15
Lt Liquid	EX4 – Not Available	**2 (30")**
Lt Liquid	Control Valves	3
		58

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Tuesday, May 21, 2013 9:16 AM
To: Janice West
Subject: RE: crude analyses
Attachments: TANK Speciation.pdf

Attached is a comparison of the results of the Canadian Crude Speciation vs. the speciation used in the submitted calculations. Only n-hexane was detected at a slightly higher concentration. There will be no significant impact on the HRA results, but we will be submitting revised calculations based on the higher n-hexane concentration no later than tomorrow.

The results seam to confirm our position that the speciation that was used is reasonably conservative.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, May 16, 2013 10:44 AM
To: Matthews, John W
Subject: [EXTERNAL]crude analyses

Hi John,

I told Paul about your plans, and he mentioned that if you currently have other types of crude on hand, a more recent analysis of a non-Canadian crude (in addition to your planned analysis) would provide a better comparison of the relative HAP concentration of your crude slate. Either refuting or confirming the claim that Canadian crudes have more HAPs. Since you're doing analyses anyway...

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Phillips 66
Crude Oil Speciation
(Wt %)

Chemical	CAS	Wt % Used	Canadian Wt %
Cresol (mixed isomers)	1319-77-3	0.001	ND
Naphthalene	91-20-3	0.091	ND
Phenol	108-95-2	0.000	ND
1,2,4-Trimethylbenzene	95-63-6	0.281	0.047
Benzene	71-43-2	0.141	0.120
Cumene	98-82-8	0.002	ND
Cyclohexane	110-82-7	0.740	0.260
Ethylbenzene	100-41-4	0.149	0.041
n-Hexane	110-54-3	0.893	**0.960**
Toluene	108-88-3	0.577	0.230
Xylene (mixed isomers)	1330-20-7	0.944	0.207
Polycyclic Aromatic Compounds (Speciated)			
Benzo(a)phenanthrene	218-01-9	0.002	ND
PACs	N590	0.002	ND
Polynuclear Aromatic Hydrocarbons (Speciated)			
Chrysene	218-01-9	0.002	ND
Naphthalene	91-20-3	0.091	ND
PAHs (excl Naphthalene)	1151	0.002	ND

Janice West

From: Janice West
Sent: Wednesday, May 15, 2013 3:45 PM
To: 'Matthews, John W'
Subject: RE: Crude Oil Toxic Contaminant Speciation

Hi John,

I've reviewed the speciation information with Paul and had our lab verify the analysis methods. Paul (who attended the recent P66 Wilmington toxics meeting) recalled some public comments about the use of Canadian crudes, and it was suggested that they may have higher concentrations of toxics.

Do these three crude analyses represent the types of crudes that are anticipated to be stored in the new tank? Have you sampled any Canadian crudes/do you anticipate using Canadian crudes?

Which analysis was from 1996? How often are analyses of crude done? How long does this sampling and analysis take?

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Wednesday, May 15, 2013 3:11 PM
To: Janice West
Subject: Crude Oil Toxic Contaminant Speciation

The speciation used for the crude oil to be stored in the proposed tank 2640 was based on the highest concentrations of constituents reported for existing crude tanks on official reports (AER, TRI, AB2588, etc.). Two of the analyses are based on samples collected in 2004, and one sample was obtained in 1996.

Volatile Organic Compounds were analyzed by EPA Method 8260; Semivolatile Organic Compounds were analyzed by EPA Method 8270; and Metals by EPA Method 6010.

The test methods are specified in the attached spreadsheet.

Since this speciation is used on the official reports, it is considered the most accurate and reliable information currently available.

I will be sending the engineering justification for the non-bellows seal valves soon, in a separate e-mail.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

Janice West

From: Joan Niertit
Sent: Wednesday, May 15, 2013 3:39 PM
To: Janice West
Cc: Rudy Eden
Subject: RE: Crude Oil Toxic Contaminant Speciation

Methods are OK, but, as you said, the analyses were done a long time ago! Toxic compounds change from oilfield to oilfield. The email says that these were the highest concentrations ever found, so I wonder how long they've be doing sampling and analysis for this. If they've been routinely analyzing samples for 15+ years and really did pick the highest ever, then... yes, they've probably captured a good picture of worst case. IF they've only taken one or two samples, then there's no saying what the crude oil has looked like over the past 15 years... and what it might look like in the future.

From: Janice West
Sent: Wednesday, May 15, 2013 3:29 PM
To: Joan Niertit
Subject: FW: Crude Oil Toxic Contaminant Speciation

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Wednesday, May 15, 2013 3:11 PM
To: Janice West
Subject: Crude Oil Toxic Contaminant Speciation

The speciation used for the crude oil to be stored in the proposed tank 2640 was based on the highest concentrations of constituents reported for existing crude tanks on official reports (AER, TRI, AB2588, etc.). Two of the analyses are based on samples collected in 2004, and one sample was obtained in 1996.

Volatile Organic Compounds were analyzed by EPA Method 8260; Semivolatile Organic Compounds were analyzed by EPA Method 8270; and Metals by EPA Method 6010.

The test methods are specified in the attached spreadsheet.

Since this speciation is used on the official reports, it is considered the most accurate and reliable information currently available.

I will be sending the engineering justification for the non-bellows seal valves soon, in a separate e-mail.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Wednesday, May 15, 2013 3:11 PM
To: Janice West
Subject: Crude Oil Toxic Contaminant Speciation
Attachments: Test Methods.xlsx

The speciation used for the crude oil to be stored in the proposed tank 2640 was based on the highest concentrations of constituents reported for existing crude tanks on official reports (AER, TRI, AB2588, etc.). Two of the analyses are based on samples collected in 2004, and one sample was obtained in 1996.

Volatile Organic Compounds were analyzed by EPA Method 8260; Semivolatile Organic Compounds were analyzed by EPA Method 8270; and Metals by EPA Method 6010.

The test methods are specified in the attached spreadsheet.

Since this speciation is used on the official reports, it is considered the most accurate and reliable information currently available.

I will be sending the engineering justification for the non-bellows seal valves soon, in a separate e-mail.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

Phillps 66
Crude Oil Speciation

Chemical	CAS	Test Method
Nickel Compounds	N495	EPA 6010B
Zinc Compounds	N982	EPA 6010B
Cresol (mixed isomers)	1319-77-3	EPA 8270C
Naphthalene	91-20-3	EPA 8270C
Phenol	108-95-2	EPA 8270C
1,2,4-Trimethylbenzene	95-63-6	EPA 8260B
Benzene	71-43-2	EPA 8260B
Cumene	98-82-8	EPA 8260B
Cyclohexane	110-82-7	EPA 8260B (Super)
Ethylbenzene	100-41-4	EPA 8260B
n-Hexane	110-54-3	EPA 8260B (Super)
Toluene	108-88-3	EPA 8260B
Xylene (mixed isomers)	1330-20-7	EPA 8260B
Polycyclic Aromatic Compounds (Speciated)		
Benzo(a)phenanthrene	218-01-9	EPA 8270C
PACs	N590	EPA 8270C
Polynuclear Aromatic Hydrocarbons (Speciated)		
Chrysene	218-01-9	EPA 8270C
Naphthalene	91-20-3	EPA 8270C
PAHs (excl Naphthalene)	1151	EPA 8270C

Janice West

From: Janice West
Sent: Tuesday, May 14, 2013 2:59 PM
To: 'Matthews, John W'
Subject: draft crude tanks permits for your review
Attachments: draft permit _crude tanks.doc

Hi John,

Attached are the draft permits for the crude tanks project. The evaluation is still under review, so it is not final. Please let me know your comments or questions.

Btw, Based on the crude speciation, I categorized the new crude tank as a Subpart CC Group 1 tank. Let me know if this is consistent with your Subpart CC assessment. (the criteria is 2% HAPs for new construction).

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Equipment	ID No.	Conn To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 10 : STORAGE TANKS					P13.2
System 7 : DOMED EXTERNAL FLOATING ROOF TANKS					
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. 2640, CRUDE OIL, WELDED SHELL, 575000 BBL; DIAMETER: 260 FT; HEIGHT: 64 FT WITH A/N: 544857 DOME COVER, GEODESIC FLOATING ROOF, PONTOON PRIMARY SEAL, CATEGORY A METALLIC SHOE SECONDARY SEAL, CATEGORY A, RIM MOUNTED GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	Dccc			**HAP: (10) [40CFR 63 Subpart CC, #3A, 6-23-2003]**	C1.xb, E193.x, H23.17
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. 2643, CRUDE/WATER, WELDED SHELL, 11500 BBL; DIAMETER: 40 FT; HEIGHT: 48 FT WITH A/N: 544859 DOME COVER, GEODESIC FLOATING ROOF, DOUBLE DECK PRIMARY SEAL, CATEGORY A METALLIC SHOE SECONDARY SEAL, CATEGORY A, RIM MOUNTED GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	Dddd			**HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]**	C1.xc, E193.x, H23.17
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-510, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 FT; HEIGHT: 50 FT WITH A/N: ~~535286~~ 544860 DOME COVER, GEODESIC FLOATING ROOF, PONTOON~~, WELDED SHELL~~ PRIMARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE SECONDARY SEAL, CATEGORY A, SHOE MOUNTED ~~B OR BETTER, WIPER TYPE~~ GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED	D394			**HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]**	C1.xa, ~~C1.17,~~ E193.x, H23.4
STORAGE TANK, DOMED EXTERNAL FLOATING ROOF, NO. R-511, CRUDE OIL, WELDED, WITH TWO MIXERS, 320000 BBL; DIAMETER: 218 FT; HEIGHT: 50 FT WITH	D395			**HAP: (10) [40CFR 63 Subpart CC, #2, 6-23-2003]**	C1.xa, ~~C1.17,~~ E193.x, H23.4

Equipment	ID No.	Conn To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
A/N: ~~535287~~ 544861					
DOME COVER, GEODESIC					
FLOATING ROOF, PONTOON					
PRIMARY SEAL, CATEGORY A, MECHANICAL ~~METALLIC~~ SHOE					
SECONDARY SEAL, CATEGORY A, SHOE MOUNTED ~~B OR BETTER, WIPER TYPE~~					
GUIDEPOLE, GASKETED SLIDING COVER, WITH WIPER, UNSLOTTED					

CONDITIONS

PROCESS CONDITIONS

P13.2 All devices under this process are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
Benzene	40CFR61, SUBPART	FF

[40CFR 61 Subpart FF, 12-4-2003]

[Processes subject to this condition : 1, 2, 3, 4, 5, 6, 7, 8, 9, 10]

SYSTEM CONDITIONS

DEVICE CONDITIONS

~~C1.17 The operator shall limit the throughput to no more than 4.5625e+06 barrel(s) in any one year.~~

~~**[RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002]~~

~~[Devices subject to this condition : D394, D395]~~

C1.xa The operator shall limit the throughput to no more than 1.52 e+06 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D394, D395]

C1.xb The operator shall limit the throughput to no more than 2.5 e+06 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dccc]

C1.xc The operator shall limit the throughput to no more than 64,000 barrel(s) in any one calendar month.

The operator shall comply with the following throughput measurement practices.

The operator shall calculate the throughput, in barrels, by the following equation: 0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The ATLG installed shall be verified once per quarter by comparing against a manual tank level measurement. If the ATLG differs from the manual tank level measurement by more than 1.0 inch or 0.8%, whichever is greater, the ATLG shall be repaired and put back into service within 10 days. While the ATLG is being repaired, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to the discovery of the discrepancy.

In the event of a failure or routine maintenance of the ATLG, the ATLG shall be repaired (if necessary) and put back into service within 10 days of the time that the ATLG failed or was removed from service for maintenance. While the ATLG is being repaired or maintained, the throughput shall be determined by the hourly tank level data averaged from the previous 30 days prior to time that the ATLG went out of service.

The operator shall keep adequate records to show compliance with the limitations specified in this permit. Such records shall be maintained and kept on file for at least two years and shall be made available to the executive officer or his authorized representative upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dddd]

E193.x The operator shall install this equipment according to the following specifications:

The operator shall not use this equipment with materials having a Reid vapor pressure of 11 psia or greater.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : Dccc, Dddd, D394, D395]

H23.4 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1149
VOC	40CFR60, SUBPART	K

[RULE 1149, 7-14-1995; RULE 1149, 5-2-2008; **40CFR 60 Subpart K, 10-17-2000]**

[Devices subject to this condition : D394, D395, D396, D397]

H23.17 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1149
VOC	40CFR60, SUBPART	Kb

[RULE 1149, 7-14-1995; RULE 1149, 5-2-2008; **40CFR 60 Subpart Kb, 10-15-2003]**

[Devices subject to this condition : Dccc, Dddd]

Janice West

From: Michael Choi [mchoi@envaudit.com]
Sent: Monday, May 13, 2013 10:24 AM
To: Janice West
Cc: John.Matthews@p66.com
Subject: Phillips 66 - Tank 2643 Crude Float

Janice,

I confirmed that the crude float in Tank 2643 is not more than a few inches at the top of the tank. The goal is to move the skim oil to recovery where it can be processed. However, it is not an automated process, so the actual height is Operations dependent.

Regards,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

Janice West

From: Michael Choi [mchoi@envaudit.com]
Sent: Thursday, May 09, 2013 9:45 AM
To: Janice West
Cc: 'Matthews, John W'
Subject: RE: crude tank questions

Janice,

Tanks 510/511 have shoe mounted secondary seals. Did you want us to update the 400-E-18 forms?

Regards,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Wednesday, May 08, 2013 6:09 PM
To: Michael Choi
Cc: Matthews, John W
Subject: RE: crude tank questions

Hi Michael,

I'm reviewing the Phillips 66 crude tank emission calculations, and noted that for Tanks 510/511, you used "shoe-mounted" for the secondary seal TANKS emissions report, but the 400-E-18 form specifies "rim mounted". Can you verify that tanks 510/511 have rim-mounted secondary seals?

hanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

From: Michael Choi [mailto:mchoi@envaudit.com]
Sent: Monday, April 29, 2013 11:46 AM
To: Janice West
Cc: 'Matthews, John W'
Subject: RE: crude tank questions

Janice,

Here is the updated TANKS run for Tank 2640. I have also included a complete 400-E-GI form. The emissions did not change when the roof type was corrected to pontoon.

Please contact me with any further questions or comments.

Regards,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Friday, April 26, 2013 3:26 PM
To: 'Marcia Baverman'
Cc: 'Michael Choi'
Subject: FW: crude tank questions

Copy of transmittal for your file.

From: Matthews, John W
Sent: Friday, April 26, 2013 1:40 PM
To: 'Janice West'
Subject: RE: crude tank questions

1. The cost estimate for doming Tanks 510 and 511 was $2.5MM, and bids are coming in lower than that. The cost estimate to replace Tanks 510 and 511 is $13.5MM. The ratio of the doming cost to the replacement cost is 18.5%. The construction cost is less than 50% of the replacement cost, therefore the doming project is not reconstruction.

2. More detailed design data has justified lighter roofs for the proposed tanks reducing the number of legs required. Revised emission calculations have been prepared consistent with the updated 400-E-18 forms. The revised emission calculations and the updated 400-E-18 forms are attached in 400-e-gi... and Signed E-18..., respectively.

3. The scaling factor used to compensate for the difference in the size of the legs is the ratio of the diameters (4/3). The emissions are estimated by taking the difference between the 3" leg run and the legless run and applying the scaling factor to the difference in emissions and adding that result to the legless emissions.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Monday, April 22, 2013 2:49 PM
To: Matthews, John W
Subject: [EXTERNAL]crude tank questions

Hi John,

Please let me know whether the tank doming for Tanks 510 and 511 has costs high enough to constitute reconstruction. I'm guessing it doesn't, but would like you to confirm.

When comparing the TANKS calculation you provided with the 400-E-18 for Tank 2640, there seems to be a discrepancy between the fittings listed in the form and those used in your TANKS calculations. Specifically, Form 400-E-18 shows 6 access hatches and 0 ladder wells, and TANKS shows 4 access hatches and 1 ladder well.

For Tank 510/511, Form 400-E-18 shows:

400-E-18	TANKS	Category
0	1	Roof drains, 90% closed
33	34	Roof leg (3-in diam.)/Adjustable, Pontoon Area, Gasketed
75	77	Roof Leg (3-in diam.)/Adjustable, Center Area, Gasketed

Please let me know which are the correct fittings. The forms seem to have changed since the last time they were submitted.

Also, precisely how did you scale the leg emissions (3" vs 4" legs)?

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
west@aqmd.gov

Janice West

From: Michael Choi [mchoi@envaudit.com]
Sent: Thursday, May 09, 2013 4:36 PM
To: Gary.Stutheit@jacobs.com
Cc: John.Matthews@p66.com; Janice West
Subject: P66 - Tank 2643 Crude Content

Gary,

Please confirm that the crude content of Tank 2643 is not more than a few inches of float at the top of the tank (<2%).

Cheers,

Michael Choi
Air Quality Specialist | Environmental Audit, Inc.
714.632.8521 x 227 | mchoi@envaudit.com

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Monday, April 29, 2013 2:56 PM
To: Janice West
Subject: RE: crude vapor speciation for fugitive emissions

The values for crude vapor wt % (in the Table below) are based on Raoult's Law calculations performed within TANKS for the June meteorological conditions, because June is considered to be the worst case for emissions.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Monday, April 29, 2013 11:55 AM
To: Matthews, John W
Subject: [EXTERNAL]crude vapor speciation for fugitive emissions

Hi John,

You sent me the crude liquid hybrid wt% of HAPs, but can you tell me the origin of the crude vapor wt% of HAPs that you're using for speciation of fugitive emissions?

Chemical	CAS	Crude Hybrid (1) Wt%	crude vapor wt%
1,2,4-Trimethylbenzene	95-63-6	0.2812269	0.01
Benzene	71-43-2	0.1414124	2.83
Chrysene	218-01-9	0.002	0
Cresol (mixed isomers)	1319-77-3	0.0005707	0
Cumene (isopropyl benzene)	98-82-8	0.002471	0
Cyclohexane	110-82-7	0.74	19.14
Ethylbenzene	100-41-4	0.1492876	0.13
Hexane	110-54-3	0.8933333	38.55
Naphthalene	91-20-3	0.0914786	0
Phenol	108-95-2	0.0002283	0
Toluene	108-88-3	0.5772455	1.01
Xylene (mixed isomers)	1330-20-7	0.9441758	0.19
unidentified		96.17657	38.14
		100	100

I received Michael Choi's updated information for Tank 2640. Pontoon vs double deck is something that's listed in the equipment description, so I wanted to be sure that it's a pontoon roof.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Michael Choi [mchoi@envaudit.com]
Sent: Monday, April 29, 2013 11:46 AM
To: Janice West
Cc: 'Matthews, John W'
Subject: RE: crude tank questions
Attachments: 05 - 400-e-gi Supplemental.pdf; Attachment B (rev1).pdf

Janice,

Here is the updated TANKS run for Tank 2640. I have also included a complete 400-E-GI form. The emissions did not change when the roof type was corrected to pontoon.

Please contact me with any further questions or comments.

Regards,

Michael Choi
r Quality Specialist | Environmental Audit, Inc.
14.632.8521 x 227 | mchoi@envaudit.com

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Friday, April 26, 2013 3:26 PM
To: 'Marcia Baverman'
Cc: 'Michael Choi'
Subject: FW: crude tank questions

Copy of transmittal for your file.

From: Matthews, John W
Sent: Friday, April 26, 2013 1:40 PM
To: 'Janice West'
Subject: RE: crude tank questions

1. The cost estimate for doming Tanks 510 and 511 was $2.5MM, and bids are coming in lower than that. The cost estimate to replace Tanks 510 and 511 is $13.5MM. The ratio of the doming cost to the replacement cost is 18.5%. The construction cost is less than 50% of the replacement cost, therefore the doming project is not reconstruction.

2. More detailed design data has justified lighter roofs for the proposed tanks reducing the number of legs required. Revised emission calculations have been prepared consistent with the updated 400-E-18 forms. The revised emission calculations and the updated 400-E-18 forms are attached in 400-e-gi... and Signed E-18..., respectively.

3. The scaling factor used to compensate for the difference in the size of the legs is the ratio of the diameters (4/3). The emissions are estimated by taking the difference between the 3" leg run and the legless run and applying the scaling factor to the difference in emissions and adding that result to the legless emissions.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Monday, April 22, 2013 2:49 PM
To: Matthews, John W
Subject: [EXTERNAL]crude tank questions

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For Tank 510/511, Form 400-E-18 shows:

400-E-18	TANKS	Category
0	1	Roof drains, 90% closed
33	34	Roof leg (3-in diam.)/Adjustable, Pontoon Area, Gasketed
75	77	Roof Leg (3-in diam.)/Adjustable, Center Area, Gasketed

Please let me know which are the correct fittings. The forms seem to have changed since the last time they were submitted.

Also, precisely how did you scale the leg emissions (3" vs 4" legs)?

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From:	Matthews, John W [John.Matthews@p66.com]
Sent:	Friday, April 26, 2013 1:40 PM
To:	Janice West
Subject:	RE: crude tank questions
Attachments:	05 - 400-e-gi Supplemental.pdf; 06 - Signed E-18 Forms.pdf

1. The cost estimate for doming Tanks 510 and 511 was $2.5MM, and bids are coming in lower than that. The cost estimate to replace Tanks 510 and 511 is $13.5MM. The ratio of the doming cost to the replacement cost is 18.5%. The construction cost is less than 50% of the replacement cost, therefore the doming project is not reconstruction.

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Sent: Monday, April 22, 2013 2:49 PM
To: Matthews, John W
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Please let me know which are the correct fittings. The forms seem to have changed since the last time they were submitted.

Also, precisely how did you scale the leg emissions (3" vs 4" legs)?

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) ( ) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) (●) Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: 2640 — Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics

- Shell Diameter (ft.): 260
- Shell Length (ft.):
- Shell Height (ft.): 65
- Turnovers Per Year: 60
- Is Tank Heated? ( ) Yes (●) No
- Is Tank Underground? ( ) Yes (●) No
- Net Throughput (gal/year): 1260MM
- Self Support Roof: (●) Yes ( ) No
- Number of Columns? 0
- Effective Column Diameter: ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1
- External Shell Condition: (●) Good ( ) Poor
- Internal Shell Color: (●) Light Rust ( ) Dense Rust ( ) Gunite Lining
- External Shell Color: (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer
- Average Liquid Height (ft.) (Vertical Only): 30
- Maximum Liquid Height (ft.) (Vertical Only): 60
- Working Volume (gal.) (Vertical Only): 21005922
- Actual Volume (gal.) (Vertical Only): 25815552
- Paint Condition: (●) Good ( ) Poor
- Paint Color/Shade: (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer

Roof Characteristics (Floating Roof Tank)

- Roof Type: ( ) Pontoon ( ) Double Deck (●) Dome Roof (Height 53 ft.) ( ) Cone Roof (Height ____ ft.)
- Roof Fitting Category: ( ) Typical (●) Detail
- Roof Height (ft.):
- Roof Paint Condition: (●) Good ( ) Poor
- Roof Color/Shade: (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer

Deck Characteristics (Floating Roof Tank)

- Deck Type: (●) Welded ( ) Bolted
- Deck Fitting Characteristics: ( ) Typical ( ) Detailed (Complete Deck Seam)
- Construction: ( ) Sheet ( ) Panel
- Deck Seam Length (ft.):
- Deck Seam: ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.

Tank Construction and Rim-Seal System (Floating Roof Tank)

- Tank Construction: (●) Welded ( ) Riveted
- Primary Seal: (●) Mechanical Shoe ( ) Vapor Mounted ( ) Liquid Mounted
- Secondary Seal: (●) Rim Mounted ( ) Shoe Mounted ( ) None

Breather Vent Setting

- Vacuum Setting (psig):
- Pressure Setting (psig):

* Section D of the application MUST be completed.

South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (°F): 64.31 Annual Average Minimum Temperature (°F): 54.40

Annual Average Maximum Temperature (°F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 • ft • day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number: ____________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box) Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent: ____________ Name of Materials Dissolved: ____________

Concentration of Materials Dissolved: ________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - __4__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - __1__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
   - 1 Weighted Mechanical Actuation, Gasketed
   - ___ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
   - ___ Sliding Cover, Gasketed
   - ___ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
   - ___ Weighted Mechanical Actuation, Gasketed
   - ___ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
   - ___ Open
   - 3 90% Close

8. Roof Leg (3" diameter leg)
   - ___ Adjustable, Pontoon Area, Ungasketed
   - ___ Adjustable, Center Area, Ungasketed
   - ___ Adjustable, Double-Deck Roofs
   - ___ Fixed
   - 34 Adjustable, Pontoon Area, Gasketed
   - ___ Adjustable, Pontoon Area, Sock
   - 134 Adjustable, Center Area, Gasketed
   - ___ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
   - ___ Adjustable
   - ___ Fixed

10. Sample Pipe (24" diameter)
    - ___ Slotted Pipe – Sliding Cover, Gasketed
    - ___ Slotted Pipe – Sliding Cover, Ungasketed
    - ___ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
    - ___ Ungasketed, Sliding Cover, Without Float
    - ___ Ungasketed Sliding Cover, With Float
    - ___ Gasketed Sliding Cover, Without Float
    - ___ Gasketed Sliding Cover, With Float
    - ___ Gasketed Sliding Cover, With Pole Sleeve
    - ___ Gasketed Sliding Cover, With Pole Wiper
    - ___ Gasketed Sliding Cover, With Float, Wiper
    - ___ Gasketed Sliding Cover, With Float, Sleeve, Wiper
    - ___ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ___ Stub Drain (1" diameter)

13. Unslotted Guide - Pole Well
    - ___ Ungasketed, Sliding Cover
    - ___ Gasketed Sliding Cover
    - ___ Ungasketed Sliding Cover with Sleeve
    - ___ Gasketed Sliding Cover with Sleeve
    - 3 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
    - 5 Weighted Mechanical Actuation, Gasketed
    - ___ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav Date: 4/26/13	Name: Marcia Baverman
	Title: Project Manager Company Name: Environmental Audit Inc.	Phone #: (714) 632-8521 Fax #: (714) 632-6754 Email: mbaverman@envaudit.com
Contact Info	Name: John Matthews	Phone #: (310) 952-6213 Fax #:
	Title: Env. Engineer Company Name: Philips 66	Email: John.Matthews@p66.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

◉ Fixed Location ○ Various Locations

Tank Type (Select ONE): ○ External Floating Roof Tank (EFRT) ○ Internal Floating Roof Tank (IFRT) ○ Horizontal Tank (HT) ○ Vertical Fixed Roof Tank (VFRT) ◉ Domed External Roof Tank (DEFRT)

Identification: Tank Identification Number: 2643 — Tank Contents/Product (include MSDS): Salt water draw from crude oil (RVP 11) storage tanks

Section B - Tank Information

Tank Characteristics

Shell Diameter (ft.): 44
Shell Length (ft.):
Shell Height (ft.): 52
Turnovers Per Year: 77

Is Tank Heated? ○ Yes ◉ No
Is Tank Underground? ○ Yes ◉ No
Net Throughput (gal/year): 32.256MM
Self Support Roof: ◉ Yes ○ No

Number of Columns? 0
Effective Column Diameter: ○ 9" by 7" Built Up Column - 1.1 ○ 8" Diameter Pipe - 0.7 ○ Unknown - 1

External Shell Condition: ◉ Good ○ Poor
Internal Shell Color: ◉ Light Rust ○ Dense Rust ○ Gunite Lining
External Shell Color: ◉ White/White ○ Aluminum/Specular ○ Aluminum/Diffuse ○ Gray/Light ○ Gray/Medium ○ Red/Primer

Average Liquid Height (ft.) (Vertical Only): 30
Maximum Liquid Height (ft.) (Vertical Only): 45
Working Volume (gal.) (Vertical Only): 421470
Actual Volume (gal.) (Vertical Only): 586782

Paint Condition: ◉ Good ○ Poor
Paint Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer

Roof Characteristics (Floating Roof Tank)

Roof Type: ○ Pontoon ○ Double Deck ◉ Dome Roof (Height 7 ft.) ○ Cone Roof (Height ____ ft.)
Roof Fitting Category: ○ Typical ◉ Detail
Roof Height (ft.):

Roof Paint Condition: ◉ Good ○ Poor
Roof Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer

Deck Characteristics (Floating Roof Tank)

Deck Type: ◉ Welded ○ Bolted
Deck Fitting Characteristics: ○ Typical ○ Detailed (Complete Deck Seam)

Construction: ○ Sheet ○ Panel
Deck Seam Length (ft.):
Deck Seam: ○ 5 ft. wide ○ 6 ft. wide ○ 7 ft. wide ○ 5 x 7.5 ft. ○ 5 x 12 ft.

Tank Construction and Rim Seal System (Floating Roof Tank)

Tank Construction: ◉ Welded ○ Riveted
Primary Seal: ◉ Mechanical Shoe ○ Liquid Mounted ○ Vapor Mounted
Secondary Seal: ◉ Rim Mounted ○ None ○ Shoe Mounted

Breather Vent Setting

Vacuum Setting (psig):
Pressure Setting (psig):

* Section D of the application MUST be completed.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (°F): 64.31 Annual Average Minimum Temperature (°F): 54.40

Annual Average Maximum Temperature (°F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / ($ft^3 \cdot ft \cdot day$)): 1571.65

Tank Contents

Chemical Category: ◯ Organic Liquids ◉ Crude Oil ◯ Petroleum Distillates

Liquid: ◯ Single ◉ Multiple

If Multiple, Select Speciation Option: ◯ Full Speciation ◉ Partial Speciation

◯ Various Weight Speciation ◯ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line

☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:____________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box): Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Salt water with crude oil

If material is stored in a solution, supply the following information:

Name of Solvent:____________ Name of Materials Dissolved:____________

Concentration of Materials Dissolved:________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: 3 Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - 1 Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
   - 1 Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed
5. Ladder Well (36" diameter)
   - 1 Sliding Cover, Gasketed
   - ____ Sliding Cover, Ungasketed
6. Rim Vent (6" diameter)
   - ____ Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed
7. Roof Drain (3" diameter)
   - ____ Open
   - 1 90% Close
8. Roof Leg (3" diameter leg)
   - ____ Adjustable, Pontoon Area, Ungasketed
   - ____ Adjustable, Center Area, Ungasketed
   - 12 Adjustable, Double-Deck Roofs
   - ____ Fixed
   - ____ Adjustable, Pontoon Area, Gasketed
   - ____ Adjustable, Pontoon Area, Sock
   - ____ Adjustable, Center Area, Gasketed
   - ____ Adjustable, Center Area, Sock
9. Roof Leg or Hang Well
   - ____ Adjustable
   - ____ Fixed
10. Sample Pipe (24" diameter)
    - ____ Slotted Pipe – Sliding Cover, Gasketed
    - ____ Slotted Pipe – Sliding Cover, Ungasketed
    - ____ Slit Fabric Seal, 10% Open
11. Guided Pole/Sample Well
    - ____ Ungasketed, Sliding Cover, Without Float
    - ____ Ungasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, Without Float
    - ____ Gasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, With Pole Sleeve
    - ____ Gasketed Sliding Cover, With Pole Wiper
    - ____ Gasketed Sliding Cover, With Float, Wiper
    - ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
    - ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper
12. ____ Stub Drain (1" diameter)
13. Unslotted Guide - Pole Well
    - ____ Ungasketed, Sliding Cover
    - ____ Gasketed Sliding Cover
    - ____ Ungasketed Sliding Cover with Sleeve
    - ____ Gasketed Sliding Cover with Sleeve
    - 3 Gasketed Sliding Cover with Wiper
14. Vacuum Breaker (10" diameter well)
    - 1 Weighted Mechanical Actuation, Gasketed
    - ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav	Date: 4/26/13	Name: Marcia Baverman
			Phone #: (714) 632-8521 Fax #: (714) 632-6754
	Title: Project Manager	Company Name: Environmental Audit Inc.	Email: mbaverman@envaudit.com
Contact Info	Name: John Matthews		Phone #: (310) 952-6213 Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: John.Matthews@p66.com

THIS IS A PUBLIC DOCUMENT

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Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

(•) Fixed Location ( ) Various Locations

Tank Type (Select ONE)
( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) ( ) Horizontal Tank (HT)
( ) Vertical Fixed Roof Tank (VFRT) (•) Domed External Roof Tank (DEFRT)

Identification
Tank Identification Number: R-510
Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics

Shell Diameter (ft.): 218
Shell Length (ft.):
Shell Height (ft.): 50
Turnovers Per Year: 64

Is Tank Heated? ( ) Yes (•) No
Is Tank Underground? ( ) Yes (•) No
Net Throughput (gal/year): 756MM
Self Support Roof: (•) Yes ( ) No

Number of Columns? 0
Effective Column Diameter: ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1

External Shell Condition: (•) Good ( ) Poor
Internal Shell Color: (•) Light Rust ( ) Dense Rust ( ) Gunite Lining
External Shell Color: (•) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer

Average Liquid Height (ft.) (Vertical Only): 25
Maximum Liquid Height (ft.) (Vertical Only): 43
Working Volume (gal.) (Vertical Only): 11970000
Actual Volume (gal.) (Vertical Only): 13440000

Paint Condition: (•) Good ( ) Poor
Paint Color/Shade: (•) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer

Roof Characteristics (Floating Roof Tank)

Roof Type: ( ) Pontoon ( ) Double Deck (•) Dome Roof (Height 42 ft.) ( ) Cone Roof (Height ____ ft.)
Roof Fitting Category: ( ) Typical (•) Detail
Roof Height (ft.):

Roof Paint Condition: (•) Good ( ) Poor
Roof Color/Shade: (•) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer

Deck Characteristics (Floating Roof Tank)

Deck Type: (•) Welded ( ) Bolted
Deck Fitting Characteristics: ( ) Typical ( ) Detailed (Complete Deck Seam)
Construction: ( ) Sheet ( ) Panel
Deck Seam Length (ft.):
Deck Seam: ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.

Tank Construction and Rim-Seal System (Floating Roof Tank)

Tank Construction: (•) Welded ( ) Riveted
Primary Seal: (•) Mechanical Shoe ( ) Vapor Mounted ( ) Liquid Mounted
Secondary Seal: (•) Rim Mounted ( ) Shoe Mounted ( ) None

Breather Vent Setting

Vacuum Setting (psig):
Pressure Setting (psig):

* Section D of the application MUST be completed.

South Coast Air Quality Management District
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Tel: (909) 396-3385
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Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (°F): 64.31 Annual Average Minimum Temperature (°F): 54.40

Annual Average Maximum Temperature (°F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 • ft • day)): 1571.65

Tank Contents

Chemical Category: ◯ Organic Liquids ◉ Crude Oil ◯ Petroleum Distillates

Liquid: ◯ Single ◉ Multiple

If Multiple, Select Speciation Option: ◯ Full Speciation ◉ Partial Speciation ◯ Various Weight Speciation ◯ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box): Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent:________ Name of Materials Dissolved:________

Concentration of Materials Dissolved:________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: 3 Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

South Coast Air Quality Management District

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Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
   - 1 Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
   - 1 Sliding Cover, Gasketed
   - ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
   - ____ Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
   - ____ Open
   - 1 90% Close

8. Roof Leg (3" diameter leg)
   - ____ Adjustable, Pontoon Area, Ungasketed
   - ____ Adjustable, Center Area, Ungasketed
   - ____ Adjustable, Double-Deck Roofs
   - ____ Fixed
   - 34 Adjustable, Pontoon Area, Gasketed
   - ____ Adjustable, Pontoon Area, Sock
   - 77 Adjustable, Center Area, Gasketed
   - ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
   - ____ Adjustable
   - ____ Fixed

10. Sample Pipe (24" diameter)
    - ____ Slotted Pipe – Sliding Cover, Gasketed
    - ____ Slotted Pipe – Sliding Cover, Ungasketed
    - ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
    - ____ Ungasketed, Sliding Cover, Without Float
    - ____ Ungasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, Without Float
    - ____ Gasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, With Pole Sleeve
    - ____ Gasketed Sliding Cover, With Pole Wiper
    - ____ Gasketed Sliding Cover, With Float, Wiper
    - ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
    - ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ Stub Drain (1" diameter)

13. Unslotted Guide – Pole Well
    - ____ Ungasketed, Sliding Cover
    - ____ Gasketed Sliding Cover
    - ____ Ungasketed Sliding Cover with Sleeve
    - ____ Gasketed Sliding Cover with Sleeve
    - 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
    - 2 Weighted Mechanical Actuation, Gasketed
    - ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav	Date: 4/26/13	Name: Marcia Baverman	
	Title: Project Manager	Company Name: EAI	Phone #: (714) 632-8521	Fax #: (714) 632-6754
			Email: mbaverman@envaudit.com	
Contact Info	Name: John Matthews		Phone #: (310) 952-6213	Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: John.Matthews@p66.com	

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Storage Tank

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Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) ( ) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) (●) Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: R-511 — Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics

- Shell Diameter (ft.): 218
- Shell Length (ft.):
- Shell Height (ft.): 50
- Turnovers Per Year: 64
- Is Tank Heated? ( ) Yes (●) No
- Is Tank Underground? ( ) Yes (●) No
- Net Throughput (gal/year): 756MM
- Self Support Roof: (●) Yes ( ) No
- Number of Columns? 0
- Effective Column Diameter: ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1
- External Shell Condition: (●) Good ( ) Poor
- Internal Shell Color: (●) Light Rust ( ) Dense Rust ( ) Gunite Lining
- External Shell Color: (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer
- Average Liquid Height (ft.) (Vertical Only): 25
- Maximum Liquid Height (ft.) (Vertical Only): 43
- Working Volume (gal.) (Vertical Only): 11970000
- Actual Volume (gal.) (Vertical Only): 13440000
- Paint Condition: (●) Good ( ) Poor
- Paint Color/Shade: (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer

Roof Characteristics (Floating Roof Tank)

- Roof Type: ( ) Pontoon ( ) Double Deck (●) Dome Roof (Height 42 ft.) ( ) Cone Roof (Height ____ ft.)
- Roof Fitting Category: ( ) Typical (●) Detail
- Roof Height (ft.):
- Roof Paint Condition: (●) Good ( ) Poor
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- Deck Type: (●) Welded ( ) Bolted
- Deck Fitting Characteristics: ( ) Typical ( ) Detailed (Complete Deck Seam)
- Construction: ( ) Sheet ( ) Panel
- Deck Seam Length (ft.):
- Deck Seam: ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.

Tank Construction and Rim-Seal System (Floating Roof Tank)

- Tank Construction: (●) Welded ( ) Riveted
- Primary Seal: (●) Mechanical Shoe ( ) Vapor Mounted ( ) Liquid Mounted
- Secondary Seal: (●) Rim Mounted ( ) Shoe Mounted ( ) None

Breather Vent Setting

- Vacuum Setting (psig):
- Pressure Setting (psig):

* Section D of the application MUST be completed.

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Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (°F): 64.31 Annual Average Minimum Temperature (°F): 54.40

Annual Average Maximum Temperature (°F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 • ft • day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

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Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:__________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box) Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent:__________ Name of Materials Dissolved:__________

Concentration of Materials Dissolved:__________ % by Weight OR __________ % by Volume OR __________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: 3 Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
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South Coast Air Quality Management District

Form 400-E-18
Storage Tank

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Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
   - 1 Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
   - 1 Sliding Cover, Gasketed
   - ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
   - ____ Weighted Mechanical Actuation, Gasketed
   - ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
   - ____ Open
   - 1 90% Close

8. Roof Leg (3" diameter leg)
   - ____ Adjustable, Pontoon Area, Ungasketed
   - ____ Adjustable, Center Area, Ungasketed
   - ____ Adjustable, Double-Deck Roofs
   - ____ Fixed
   - 34 Adjustable, Pontoon Area, Gasketed
   - ____ Adjustable, Pontoon Area, Sock
   - 77 Adjustable, Center Area, Gasketed
   - ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
   - ____ Adjustable
   - ____ Fixed

10. Sample Pipe (24" diameter)
    - ____ Slotted Pipe – Sliding Cover, Gasketed
    - ____ Slotted Pipe – Sliding Cover, Ungasketed
    - ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
    - ____ Ungasketed, Sliding Cover, Without Float
    - ____ Ungasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, Without Float
    - ____ Gasketed Sliding Cover, With Float
    - ____ Gasketed Sliding Cover, With Pole Sleeve
    - ____ Gasketed Sliding Cover, With Pole Wiper
    - ____ Gasketed Sliding Cover, With Float, Wiper
    - ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
    - ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ Stub Drain (1" diameter)

13. Unslotted Guide – Pole Well
    - ____ Ungasketed, Sliding Cover
    - ____ Gasketed Sliding Cover
    - ____ Ungasketed Sliding Cover with Sleeve
    - ____ Gasketed Sliding Cover with Sleeve
    - 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
    - 2 Weighted Mechanical Actuation, Gasketed
    - ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav	Date: 9/26/13	Name: Marcia Baverman	
	Title: Project Manager	Company Name: Environmenal Audit Inc.	Phone #: (714) 632-8521	Fax #: (714) 632-6754
			Email: mbaverman@envaudit.com	
Contact Info	Name: John Matthews		Phone #: (310) 952-6213	Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: John.Matthews@p66.com	

AQMD Form 400-E-GI

Philips 66 – Los Angeles Refinery Carson Plant
Facility ID No. 171109

Permit Application

Supplemental Information Package
Crude Oil Storage Capacity Project Tanks

Sections

1. Company Information
2. Background
3. Project Description
4. Equipment Location and Description
5. Operating Schedule
6. Emission Calculations
7. Evaluation and Rule Review
8. Proposed Permit Conditions
9. Confidentiality

Attachments

A Figures
B Emission Calculations
C Tank R510 NSR Balance
D Rule 1401 Analyses

April 26, 2013

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1. COMPANY INFORMATION

Mailing Address
1660 W. Anaheim St.
Wilmington, CA 90744

Site Location
Carson Plant
1520 E. Sepulveda Blvd.
Carson, CA 90745

2. BACKGROUND

The Philips 66 Los Angeles Refinery Carson Plant (LARC) operates crude supply storage tanks to handle incoming crude supplies from domestic as well as various sources from the Port of Long Beach, Berth 121.

LARC currently has four 320,000 barrel (BBL) receiving tanks (285,000 BBL net working capacity) for crude. These tanks usually store three segregated crude grades at a time, which essentially limits delivery volumes to Panamax vessels (400,000 BBL capacity). For larger vessels, such as Aframax (720,000 BBL) or Suezmax (1,000,000 BBL), LARC requires two ship calls to unload the full volume of the vessels, resulting in seven to 10 days of demurrage between ship calls. Between ship calls LARC makes room in the receiving tanks to accommodate the second discharge from the larger vessel. LARC needs more tankage and capacity to accommodate the larger vessels so they can discharge their total volume in one call.

3. PROJECT DESCRIPTION

The project will increase the onsite crude storage capacity by installing one new 614,656 BBL (500,141 BBL net working capacity) domed external floating roof crude tank (Tank 2640) and geodesic domes on two of the existing crude tanks (Tank R510 (Device D394) and Tank R511(Device D395)). The project also includes the construction of a new 13,971 BBL (10,035 BBL net working capacity) domed external floating roof water draw tank (Tank 2643).

Currently, the water draw from the existing crude tanks is processed in the sour water stripper which is at times overloaded. The water draw from the existing R510 and R511 tanks and new Tank 2640 will be routed to the new water draw Tank 2643. The new 10,035 BBL water draw tank will allow LARC to treat the water at the Brine Stripper, which has excess capacity. Minor modifications are required to prepare the water draw from Tank 2643 for delivery to the Brine Stripper, consisting of the installation of new heat exchangers and a steam trim heater to raise the temperature of the water before entering the Brine Stripper.

4. EQUIPMENT LOCATION AND TANK DESCRIPTION

The new tanks and tank modifications will be located at the western boundary of LARC. Table 1 shows the specifications of the existing and proposed tanks. Please refer to the Figures 1, 2, and 3 in Attachments A for locations.

TABLE 1
Tank Specifications

Tank Number	Roof Type	Commodity Type	Working Volume (BBL)	Diameter (ft)	Height (ft)	Dome Roof (ft)
Existing 510	Pontoon	Crude Oil	285,000	218	50	42
Existing 511	Pontoon	Crude Oil	285,000	218	50	42
Modified 510	Domed	Crude Oil RVP 7	285,000	218	50	42
Modified 511	Domed	Crude Oil RVP 7	285,000	218	50	42
New Tank 2640	Domed	Crude Oil RVP 7	500,141	260	65	53
New Tank 2643	Domed	Water/Crude	10,035	44	52	7

5. OPERATING SCHEDULE

	NORMAL	MAXIMUM
Hours/Day	24	24
Days/Week	7	7
Weeks/Year	52	52

6. EMISSION CALCULATIONS

The emissions for the tanks were calculated with the EPA TANKS 4.0.9d emissions model using a crude speciation for crude oil with a Reid Vapor Pressure of 11 (true vapor pressure 11 at 77 °F, see Figure 4). The peak daily emission rate was calculated by taking the maximum monthly value and converting to a daily rate. The new tanks will both use 4" legs instead of the standard 3" legs. Since there are no established emission factors for non-standard sized legs, emissions were scaled based on the difference in circumference between the 3" legs and 4" legs. The fugitive emissions from components were calculated using the SCAQMD correlation equations. The emission calculations can be found in Attachment B.

7. EVALUATION AND RULE REVIEW

The proposed Project is designed to comply with the standards contained in the applicable State and Federal Rules and Regulations. The following provides a brief summary of the applicable regulations.

STATE REGULATIONS

Rule 301 – Permit Fees

Per the requirements of SCAQMD Rule 301, the application fee for the tanks is $12,040.21 (Schedule C – Storage Tank, with External Floating Roof). Expedited permit processing has been requested and an additional $6,020.11 will be submitted with the permit application fee. The total application and expedited fee for the permit application is $19,849.44.

Rule 403 – Fugitive Dust

The construction activities of the proposed project are regulated under SCAQMD Rule 403 which include requirements to minimize fugitive dust using best available control measures that include applying water or chemical stabilizers to active construction sites/unpaved roads, covering all haul vehicles, and so forth.

Rule 463 – Organic Liquid Storage

The crude storage tanks are regulated under SCAQMD Rule 463, which includes requirements to minimize fugitive VOC using best available control measures that include tanks construction standards.

Rule 466 – Pumps and Compressors

Rule 466 establishes inspection, tagging, and maintenance requirements for pumps and compressors. Pumps and compressors associated with all tanks will be included in the LARC Rule 1173 compliance program and will, therefore, comply with Rule 466.

Rule 466.1 – Valves and Flanges

Rule 466.1 establishes inspection, tagging, and maintenance requirements for valves and flanges. Valves and flanges associated with all tanks will be included in the LARC Rule 1173 monitoring program and will, therefore, comply with Rule 466.1.

Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants

The LARC currently complies with Rule 1173 and has a monitoring program for leaks. The new tanks will be incorporated into the existing plan.

Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities

Rule 1178 establishes tanks standards to control fugitive VOC emissions. The new and modified tanks associated with proposed Project will comply with Rule 1178.

Regulation XIII – New Source Review

The tanks are subject to Regulation XIII and are subject to requirements to provide emission offsets. Tanks R510 and R511 were permitted pursuant to Rule 213 with an NSR for Tank R510 identified as 103.7 lbs/day (See Attachment C). Since Tank R511 is identical to Tank R510, the total NSR balance for the tanks should be 207.4 lbs/day Pursuant to Rule 1304(c)(2) a concurrent emissions reduction can be used in lieu of providing offsets for the new equipment. As shown in Table 2, no additional offsets are required for this project.

TABLE 2
Emission Reduction Credits Summary

Tank No.	Emissions (lbs/day)
Post Project Emissions	
Modified Tank 510 Crude Tank	17.04
Modified Tank 511 Crude Tank	17.04
New Tank 2640 Crude Tank	18.78
New Tank 2643 Water Draw Tank	4.21
Fugitive Emissions	9.07
Total Project Emissions	66.13
NSR Balance for Tanks 510 and 511	207.4
Offsets Required	0

Rule 1401 – New Source Review for Toxic Air Contaminants

The tanks will store crude oil which contains chemicals listed under SCAQMD Rule 1401 and considered to be toxic air contaminants. The increase in toxic air contaminants is below the Rule 1401 screening thresholds for each of the four tanks. The Rule 1401 screening analyses are included in Attachment D.

Regulation XX - RECLAIM

The facility is subject to RECLAIM, however, the project only generates VOC emissions, which is not a RECLAIM pollutant. Therefore, no RECLAIM emissions are emitted from this project.

Regulation XXX - Title V Permits

The facility is a Title V facility. Permit modification applications are included in this application package to modify the facility Title V permit. The Title V permit modification qualifies as a significant permit revision pursuant to SCAQMD Rule 3000(b)(31)(I).

FEDERAL REGULATIONS

The federal regulations applicable to the new tanks are as follows:

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984
40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006
40 CFR 61 Subpart V – National Emission Standards for Equipment Leaks (Fugitive Emission Sources)
40 CRF 61 subpart FF – National Emission Standards for Benzene Waste Operations
40 CFR 63 Subpart H – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks
40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

The federal regulations, while not identical to the state regulations, are similar to state regulations. The new and modified tanks are designed to comply with BACT requirements, the SCAQMD rules and regulations, and federal regulations. Therefore, the new and modified tanks are expected to comply with applicable subparts of the federal regulations.

8. PROPOSED PERMIT CONDITIONS

Below are the proposed permit conditions for throughput and monitoring of the tanks. These conditions should replace condition C1.17 for existing Tanks 510 and 511, and should read:

The operator shall limit the throughput to no more than 1,500,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

The conditions for new Tank 2640 should read:

The operator shall limit the throughput to no more than 2,500,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

The conditions for new Tanks 2643 should read:

The operator shall limit the throughput to no more than 64,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

9. CONFIDENTIALITY

Certain information supplied on the attached sheets concerning process operating conditions, material balances, and process descriptions constitutes confidential and proprietary information under Government Code Section 6254.7. Philips 66 justifies classification of such data as trade secrets because the information contains production data and operating procedures, and therefore would potentially release competitively sensitive information, which would be of considerable value to competitors. Therefore, we request that all such data be handled in confidence.

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ATTACHMENT A

Figures

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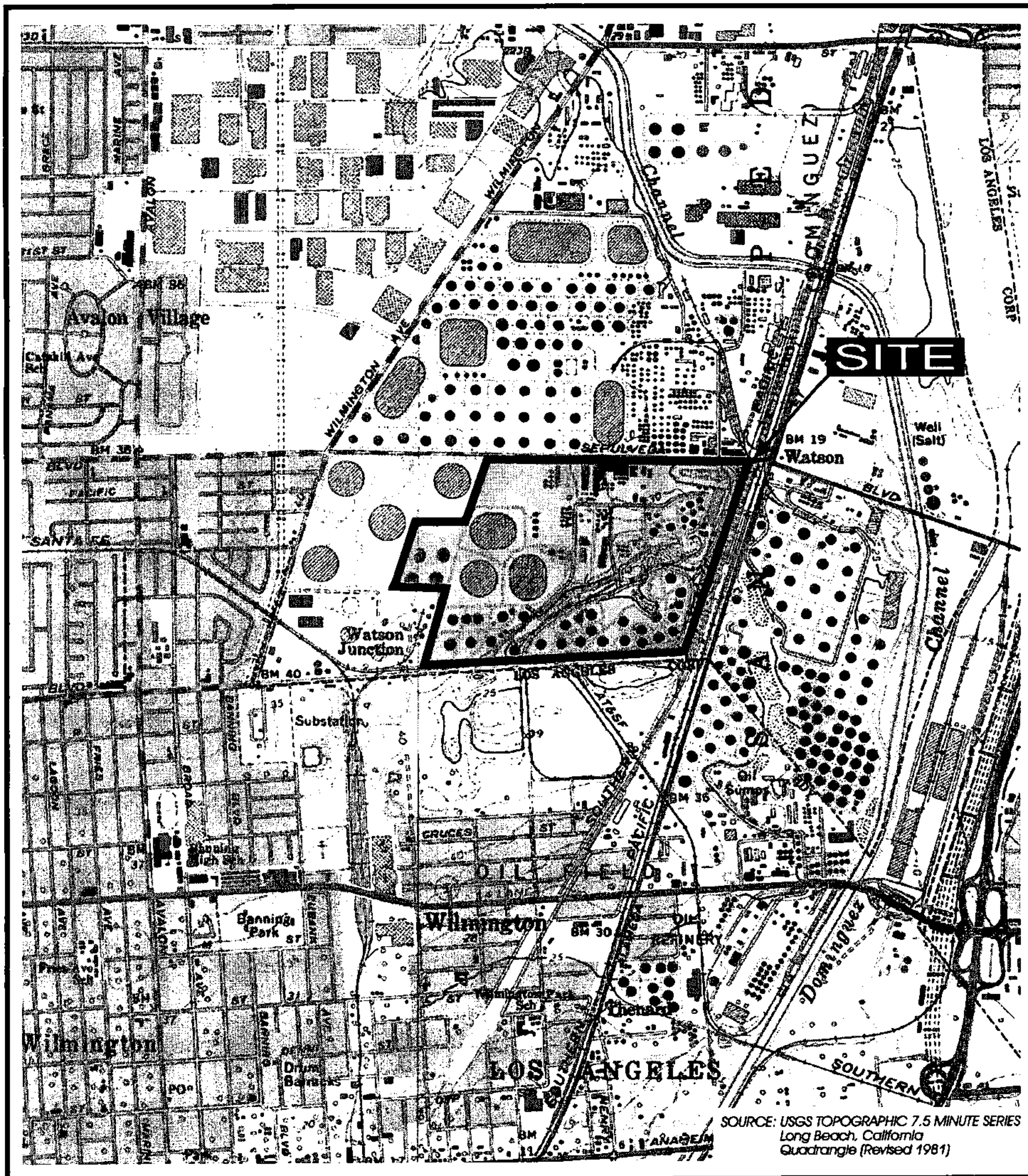

Environmental Audit, Inc.

SITE LOCATION MAP
Phillips 66 Los Angeles Refinery
Carson Plant

Project No. 2778

Figure 1

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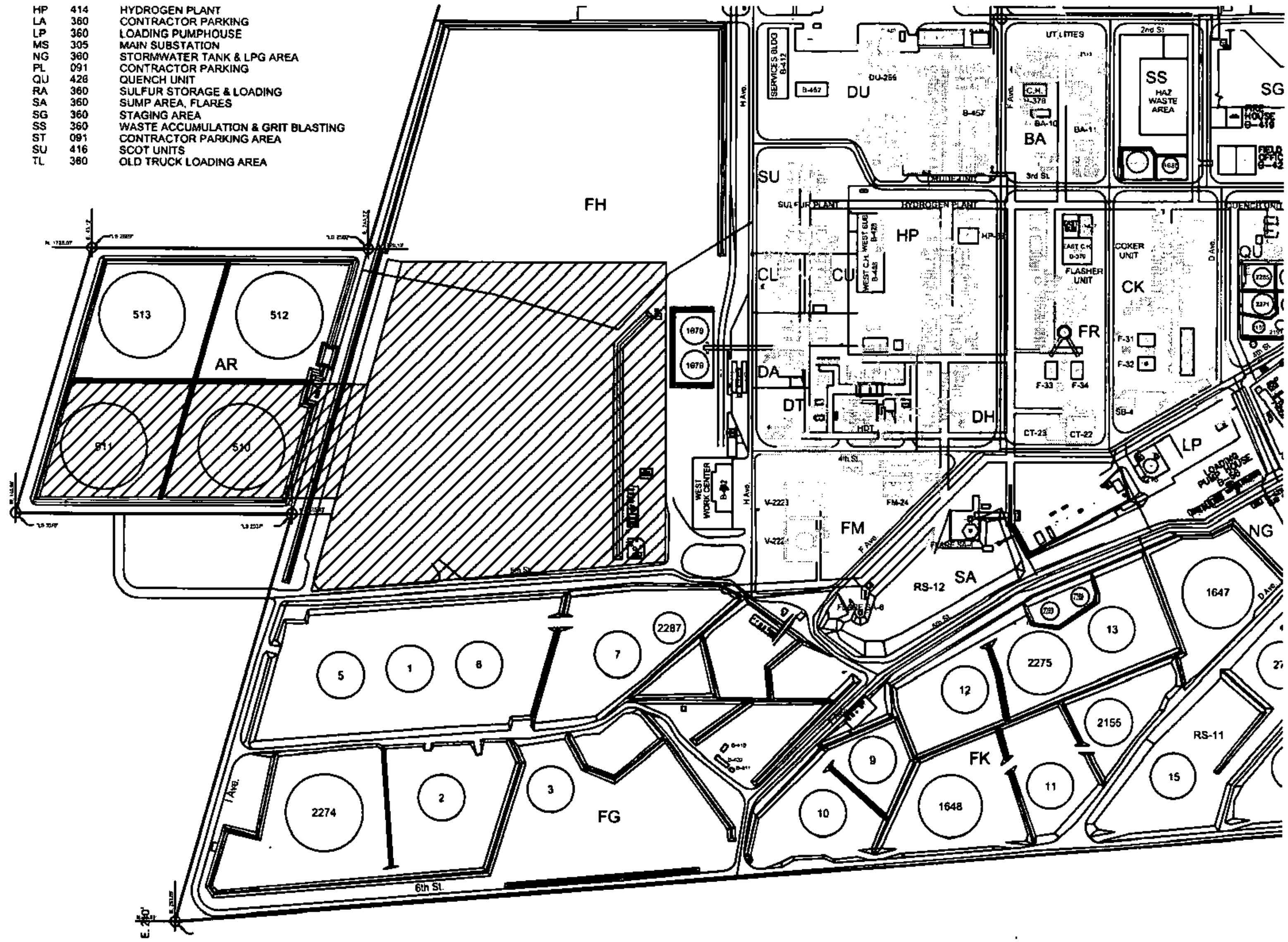
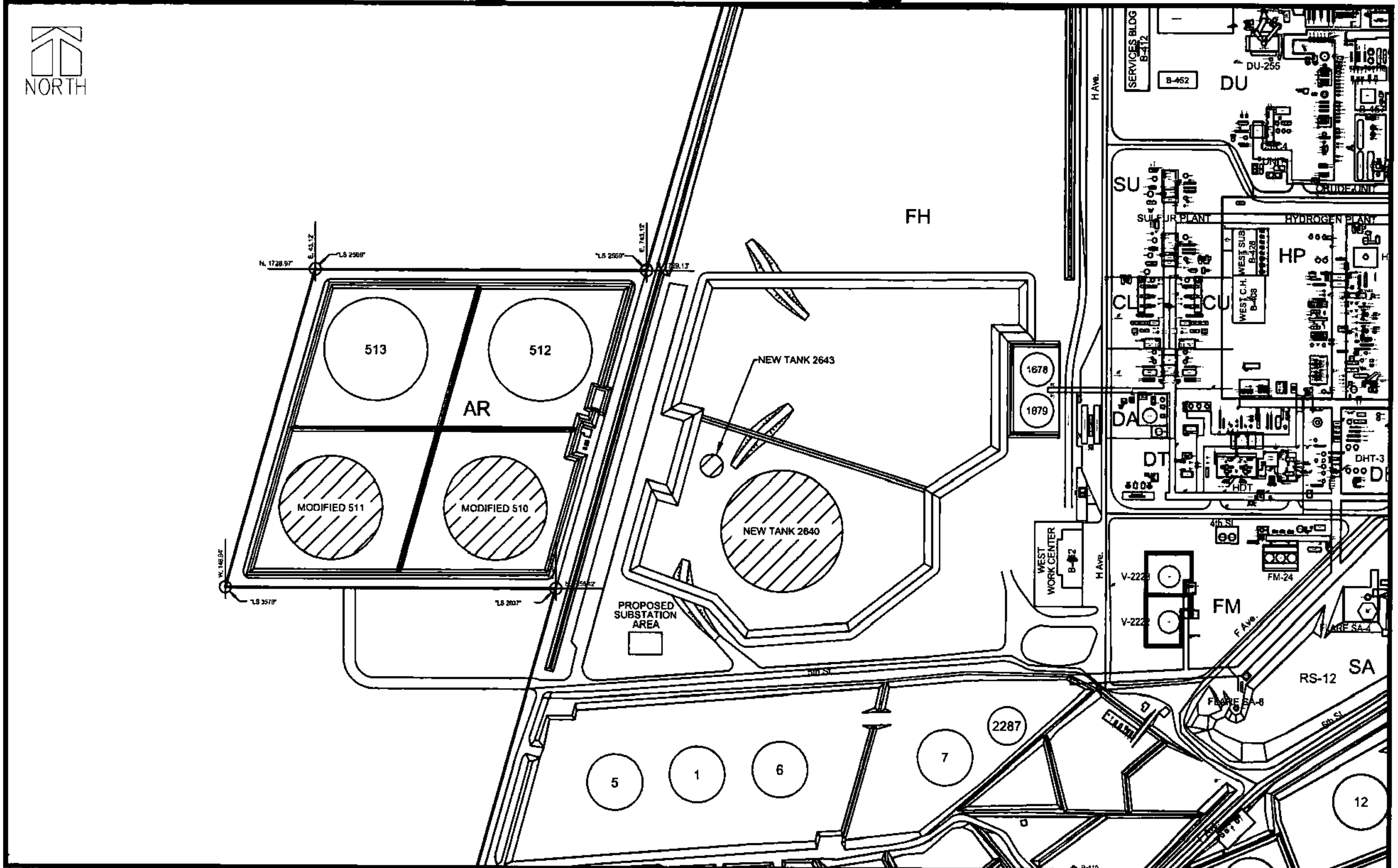
HP	414	HYDROGEN PLANT
LA	360	CONTRACTOR PARKING
LP	360	LOADING PUMPHOUSE
MS	305	MAIN SUBSTATION
NG	360	STORMWATER TANK & LPG AREA
PL	091	CONTRACTOR PARKING
QU	428	QUENCH UNIT
RA	360	SULFUR STORAGE & LOADING
SA	360	SUMP AREA, FLARES
SG	360	STAGING AREA
SS	360	WASTE ACCUMULATION & GRIT BLASTING
ST	091	CONTRACTOR PARKING AREA
SU	416	SCOT UNITS
TL	360	OLD TRUCK LOADING AREA



LEGEND:

(13) NUMBERS IN AND AROUND OBJECTS REPRESENT INDIVIDUAL TANK NUMBERS

PROPOSED PROJECT AREA



Environmental Audit, Inc.

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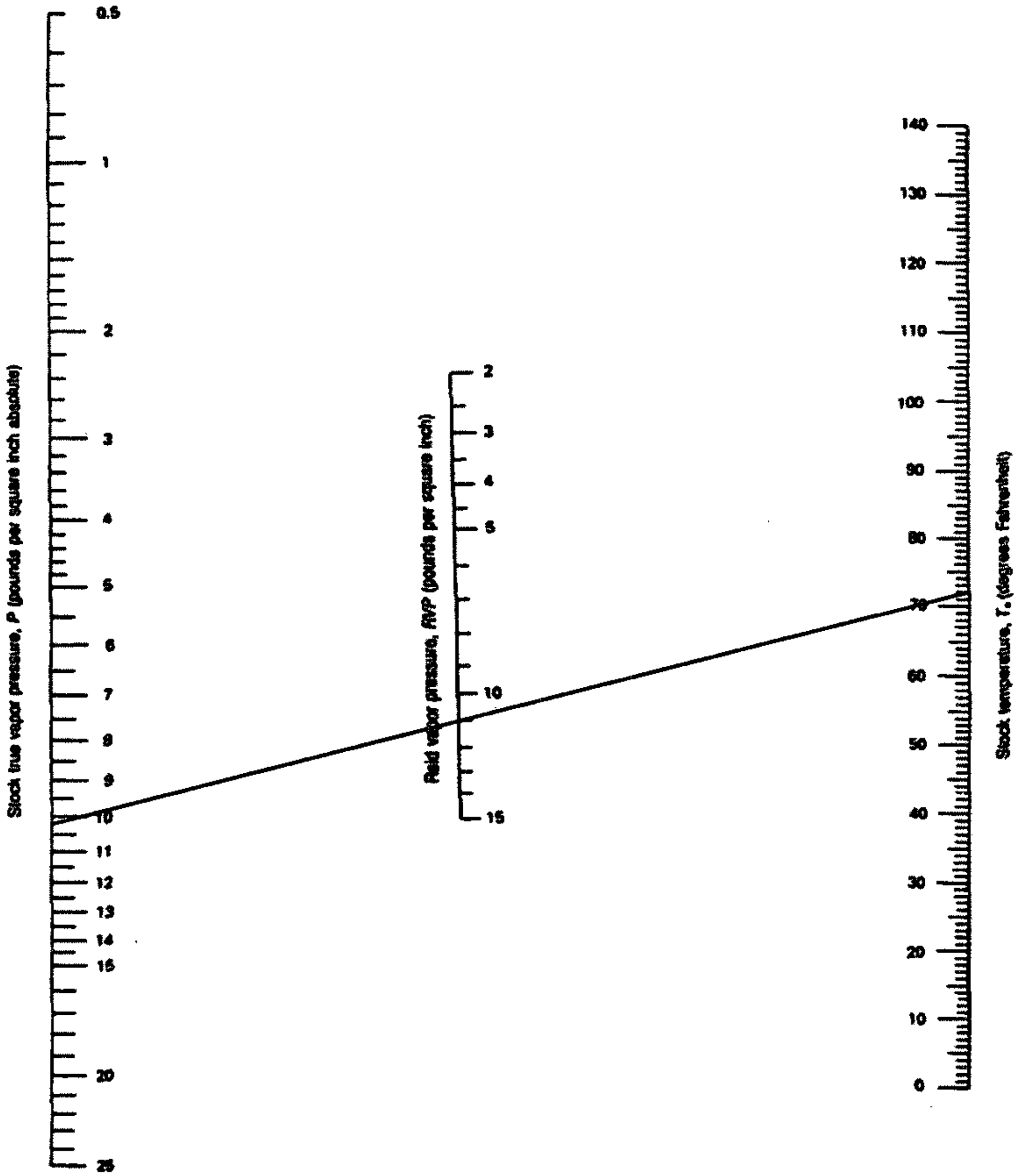
PROPOSED PROJECT PLAN
Phillips 66 Los Angeles Refinery
Carson Plant

Project No. 2778

Figure 3



True vapor pressure of crude oils with a Reid vapor pressure
of 2 to 15 pounds per square inch.

SOURCE: AP42 Figure 7.1-13a (November 2006)

Environmental Audit, Inc.

Nomograph of Crude Oil Vapor Pressure

Project No. 2778

Figure 4

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ATTACHMENT B

Emission Calculations

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Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2640**

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm) Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	190	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	14	4.55	0	63.64
		Light Liquid (4)	0	0	83	4.55	0	377.30
		Heavy Liquid (5)	0	0		4.55	0	-
		> 8 inches	0	0			0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	5	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	2	46.83	0	
Compressors		Gas / Vapor	0	0		9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	258	6.99	-	1,803.47
Connectors		All	0	0	134	2.86	-	383.43
Pressure Relief Valves		All	0	0	6		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	7	9.09	-	
Total Emissions		lb/year					-	2,628
		lbs/day					0	7.20

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: Philips 66 Carson Plant New Crude Tank 2643

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm): Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	61	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	0	4.55	0	-
		Light Liquid (4)	0	0	16	4.55	0	72.73
		Heavy Liquid (5)	0	0	0	4.55	0	-
		> 8 inches	0	0	0		0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	0	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	0	46.83	0	
Compressors		Gas / Vapor	0	0	0	9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	79	6.99	-	552.22
Connectors		All	0	0	20	2.86	-	57.23
Pressure Relief Valves		All	0	0	0		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	1	9.09	-	
Total Emissions		lb/year					-	682
		lbs/day					0	1.87

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Fugitive Component Emissions

		Tank 2640			Tank 2643		
Chemical	Crude Vapor Wt%	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	2.83	7.44E+01	0.20	8.50E-03	19.33	0.05	2.21E-03
PACs (Chrysene)	0.00	3.56E-05	0.00	4.06E-09	9.24E-06	0.00	1.06E-09
Cresol (mixed isomers)	0.00	4.28E-05	0.00	4.89E-09	1.11E-05	0.00	1.27E-09
Ethylbenzene	0.13	3.29E+00	0.01	3.76E-04	8.55E-01	0.00	9.76E-05
n-Hexane	38.55	1012.95	2.78	1.16E-01	262.96	0.72	3.00E-02
Naphthalene	0.00	2.26E-02	0.00	2.58E-06	5.87E-03	0.00	6.71E-07
Phenol	0.00	1.02E-04	0.00	1.16E-08	2.64E-05	0.00	3.01E-09
Toluene	1.01	2.66E+01	0.07	3.04E-03	6.90	0.02	7.88E-04
Xylene (mixed isomers)	0.19	5.09E+00	0.01	5.81E-04	1.32E+00	0.00	1.51E-04
Cumene	0.00	7.03E-03	0.00	8.02E-07	0.00	0.00	2.08E-07
Cyclohexane	19.14	503.08	1.38	5.74E-02	130.60	0.36	1.49E-02
1,2,4-Trimethylbenzene	0.01	3.28E-01	0.00	3.74E-05	8.51E-02	0.00	9.71E-06
Total VOC	100.00	2.63E+03	7.20	3.00E-01	682.18	1.87	7.79E-02

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Tank Working Loss Emissions

Chemical	Tank 2640[1] Emissions lb/yr	Tank 2640[1] Emissions lb/day	Tank 2640[1] Emissions lb/hr	Tank 2643[1] Emissions lb/yr	Tank 2643[1] Emissions lb/day	Tank 2643[1] Emissions lb/hr	Tank R510/R511 Emissions lb/yr	Tank R510/R511 Emissions lb/day	Tank R510/R511 Emissions lb/hr
Benzene	8.28	0.0227	9.45E-04	1.66	0.0045	1.89E-04	6.96	0.0191	7.945E-04
PACs (Chrysene)	0.09	0.0002	1.03E-05	0.01	0.0000	1.14E-06	0.07	0.0002	7.991E-06
Cresol (mixed isomers)	0.03	0.0001	3.42E-06	-	-	0.00E+00	0.02	0.0001	2.283E-06
Ethylbenzene	7.10	0.0194	8.10E-04	1.11	0.0030	1.27E-04	5.17	0.0142	5.902E-04
n-Hexane	59.02	0.1617	6.74E-03	12.99	0.0356	1.48E-03	52.95	0.1451	6.045E-03
Naphthalene	4.24	0.0116	4.84E-04	0.64	0.0018	7.31E-05	3.03	0.0083	3.459E-04
Phenol	0.01	0.0000	1.14E-06	-	-	0.00E+00	0.01	0.0000	1.142E-06
Toluene	28.79	0.0789	3.29E-03	4.83	0.0132	5.51E-04	21.79	0.0597	2.487E-03
Xylene (mixed isomers)	44.70	0.1225	5.10E-03	6.98	0.0191	7.96E-04	32.47	0.0890	3.707E-03
Cumene	0.12	0.0003	1.37E-05	0.02	0.0001	2.28E-06	0.08	0.0002	9.132E-06
Cyclohexane	42.75	0.1171	4.88E-03	8.42	0.0231	9.61E-04	35.69	0.0978	4.074E-03
1,2,4-Trimethylbenzene	13.09	0.0359	1.49E-03	2.00	0.0055	2.29E-04	9.39	0.0257	1.072E-03
Total VOC	6,634.36	18.1763	7.57E-01	1,465.21	4.0143	1.67E-01	5963.21	16.3376	6.807E-01

(1) Tank leg emissions scaled for 4" legs.

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Total Tank Operational Emissions

	Tank 2640			Tank 2643		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	82.72	0.2266	0.0094	20.98	0.0575	0.0024
PACs (Chrysene)	0.09	0.0002	0.0000	0.01	0.0000	0.0000
Cresol (mixed isomers)	0.03	0.0001	0.0000	0.00	0.0000	0.0000
Ethylbenzene	10.39	0.0285	0.0012	1.96	0.0054	0.0002
n-Hexane	1,071.97	2.9369	0.1224	275.96	0.7560	0.0315
Naphthalene	4.26	0.0117	0.0005	0.65	0.0018	0.0001
Phenol	0.01	0.0000	0.0000	0.00	0.0000	0.0000
Toluene	55.38	0.1517	0.0063	11.73	0.0321	0.0013
Xylene (mixed isomers)	49.79	0.1364	0.0057	8.30	0.0227	0.0009
Cumene	0.13	0.0003	0.0000	0.02	0.0001	0.0000
Cyclohexane	545.83	1.4954	0.0623	139.02	0.3809	0.0159
1,2,4-Trimethylbenzene	13.42	0.0368	0.0015	2.09	0.0057	0.0002
Total VOC	9,262.19	25.3759	1.0573	2,147.39	5.8833	0.2451

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2640 legged2
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity)

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,005,922.00
Turnovers:	59.98

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	5
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	134
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34
Roof Drain (3-in. Diameter)/90% Closed	3

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2640 legged2 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2640 legged2 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	57.6988	59.1515	60.6795	63.7603	66.4370	69.5218	73.9825	74.6934	71.7943	67.2977	61.5048	57.6642
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673
Net Throughput (gal/mo.):	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	75.1897	77.0828	79.0740	83.0887	86.5768	90.5967	96.4096	97.3360	93.5581	87.6984	80.1495	75.1446
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900	203.2900
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	519.1558	522.5016	526.0208	533.1163	539.2811	546.3858	556.6594	558.2967	551.6196	541.2634	527.9216	519.0761

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	5	6.20	1.20	0.94	155.9194
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3	14.00	3.70	0.78	211.2456
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	134	0.53	0.11	0.13	357.2063
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	14.0830
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	32.1898
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34	1.30	0.08	0.65	222.3109
Roof Drain (3-in. Diameter)/90% Closed	3	1.80	0.14	1.10	27.1602

TANKS 4.0.9d
Emissions Report - Detail Format

Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640 legged2 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	784.19	4,635.21	1,021.90	0.00	6,441.30
1,2,4-Trimethylbenzene	0.03	13.04	0.03	0.00	13.09
Benzene	0.68	6.55	0.88	0.00	8.11
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.12
Cyclohexene	3.31	34.30	4.32	0.00	41.93
Ethylbenzene	0.07	6.92	0.09	0.00	7.08
Hexane (-n)	6.91	41.41	9.01	0.00	57.32
Naphthalene	0.00	4.24	0.00	0.00	4.24
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.80	26.76	1.04	0.00	28.59
Unidentified Components	772.03	4,457.98	1,006.06	0.00	6,236.07
Xylenes (mixed isomers)	0.37	43.76	0.48	0.00	44.61

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2640 legless2
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity)

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,005,922.00
Turnovers:	59.98

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	5
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Roof Drain (3-in. Diameter)/90% Closed	3

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2640 legless2 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

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Emissions Report - Detail Format
Detail Calculations (AP-42)

2640 legless2 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	57.6988	59.1515	60.6795	63.7603	66.4370	69.5218	73.9825	74.6934	71.7943	67.2977	61.5048	57.6642
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673
Net Throughput (gal/mo.):	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	32.5739	33.3941	34.2567	35.9960	37.5071	39.2486	41.7669	42.1682	40.5315	37.9930	34.7226	32.5544
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700	88.0700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	476.5400	478.8129	481.2036	486.0236	490.2114	495.0377	502.0167	503.1289	498.5931	491.5580	482.4948	476.4859

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	5	6.20	1.20	0.94	155.9194
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3	14.00	3.70	0.78	211.2456
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	14.0830
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	32.1898
Roof Drain (3-in. Diameter)/90% Closed	3	1.80	0.14	1.10	27.1602

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Emissions Report - Detail Format

Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640 legless2 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	784.19	4,635.21	442.71	0.00	5,862.11
1,2,4-Trimethylbenzene	0.03	13.04	0.01	0.00	13.08
Benzene	0.68	6.55	0.38	0.00	7.61
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.12
Cyclohexene	3.31	34.30	1.87	0.00	39.48
Ethylbenzene	0.07	6.92	0.04	0.00	7.03
Hexane (-n)	6.91	41.41	3.90	0.00	52.22
Naphthalene	0.00	4.24	0.00	0.00	4.24
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.80	26.76	0.45	0.00	28.00
Unidentified Components	772.03	4,457.98	435.85	0.00	5,665.86
Xylenes (mixed isomers)	0.37	43.76	0.21	0.00	44.34

TANKS 4.0.9d

Emissions Report - Detail Format

Tank Indentification and Physical Characteristics

Identification

User Identification:	2643 legged
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	10000bbl (working capacity) domed water surge tank

Tank Dimensions

Diameter (ft):	44.00
Volume (gallons):	421,470.00
Turnovers:	76.53

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	12
Roof Drain (3-in. Diameter)/90% Closed	1
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2643 legged - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2643 legged - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	9.7644	10.0103	10.2688	10.7902	11.2432	11.7652	12.5201	12.6404	12.1498	11.3888	10.4085	9.7586
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317
Net Throughput (gal/mo.):	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000
Roof Fitting Losses (lb):	45.2381	46.3771	47.5751	49.9905	52.0892	54.5078	58.0051	58.5625	56.2895	52.7640	48.2222	45.2110
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100	122.3100
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	113.4342	114.8190	116.2756	119.2124	121.7641	124.7047	128.9569	129.6346	126.8710	122.5845	117.0624	113.4012

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	16.0949
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	14.0830
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	31.1839
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3	14.00	3.70	0.78	211.2456
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	12	0.82	0.53	0.14	49.4918
Roof Drain (3-in. Diameter)/90% Closed	1	1.80	0.14	1.10	9.0534
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2643 legged - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	132.71	701.18	614.83	0.00	1,448.72
1,2,4-Trimethylbenzene	0.00	1.97	0.02	0.00	2.00
Benzene	0.11	0.99	0.53	0.00	1.64
Chrysene	0.00	0.01	0.00	0.00	0.01
Cresol (-m)	0.00	0.00	0.00	0.00	0.00
Cumene	0.00	0.02	0.00	0.00	0.02
Cyclohexene	0.56	5.19	2.60	0.00	8.35
Ethylbenzene	0.01	1.05	0.05	0.00	1.11
Hexane (-n)	1.17	6.26	5.42	0.00	12.85
Naphthalene	0.00	0.64	0.00	0.00	0.64
Phenol	0.00	0.00	0.00	0.00	0.00
Toluene	0.13	4.05	0.63	0.00	4.81
Unidentified Components	130.65	674.37	605.30	0.00	1,410.32
Xylenes (mixed isomers)	0.06	6.62	0.29	0.00	6.97

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2643 legless
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	10000bbl (working capacity) domed water surge tank

Tank Dimensions

Diameter (ft):	44.00
Volume (gallons):	421,470.00
Turnovers:	76.53

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Drain (3-in. Diameter)/90% Closed	1
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2643 legless - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2643 legless - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	9.7644	10.0103	10.2688	10.7902	11.2432	11.7652	12.5201	12.6404	12.1498	11.3888	10.4085	9.7586
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317	58.4317
Net Throughput (gal/mo.):	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000	44.0000
Roof Fitting Losses (lb):	41.5986	42.6460	43.7476	45.9687	47.8985	50.1225	53.3385	53.8510	51.7609	48.5191	44.3426	41.5737
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700	112.4700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	109.7947	111.0879	112.4482	115.1906	117.5734	120.3195	124.2903	124.9232	122.3424	118.3396	113.1828	109.7639

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	16.0949
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	14.0830
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	31.1839
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	3	14.00	3.70	0.78	211.2456
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Roof Drain (3-in. Diameter)/90% Closed	1	1.80	0.14	1.10	9.0534
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2643 legless - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	132.71	701.18	565.37	0.00	1,399.26
1,2,4-Trimethylbenzene	0.00	1.97	0.02	0.00	1.99
Benzene	0.11	0.99	0.49	0.00	1.59
Chrysene	0.00	0.01	0.00	0.00	0.01
Cresol (-m)	0.00	0.00	0.00	0.00	0.00
Cumene	0.00	0.02	0.00	0.00	0.02
Cyclohexene	0.56	5.19	2.39	0.00	8.14
Ethylbenzene	0.01	1.05	0.05	0.00	1.11
Hexane (-n)	1.17	6.26	4.98	0.00	12.42
Naphthalene	0.00	0.64	0.00	0.00	0.64
Phenol	0.00	0.00	0.00	0.00	0.00
Toluene	0.13	4.05	0.57	0.00	4.76
Unidentified Components	130.65	674.37	556.60	0.00	1,361.62
Xylenes (mixed isomers)	0.06	6.62	0.26	0.00	6.95

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	R510/511
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	285000 bbl tank (working capacity)

Tank Dimensions

Diameter (ft):	218.60
Volume (gallons):	11,970,000.00
Turnovers:	63.16

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Pontoon
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Shoe-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Roof Drain (3-in. Diameter)/90% Closed	1
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77
Automatic Gauge Float Well/Bolted Cover, Gasketed	2
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format

Liquid Contents of Storage Tank

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777

Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	

Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d

Emissions Report - Detail Format

Detail Calculations (AP-42)

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	129.3637	132.6208	136.0466	142.9539	148.9552	155.8714	165.8725	167.4663	160.9664	150.8849	137.8970	129.2861
Seal Factor A (lb-mole/ft-yr):	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528
Net Throughput (gal/mo.):	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0050	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Roof Fitting Losses (lb):	66.0133	67.6754	69.4236	72.9483	76.0107	79.5401	84.6435	85.4569	82.1400	76.9955	70.3678	65.9738
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	471.0298	475.9490	481.1230	491.5550	500.6187	511.0643	526.1688	528.5760	518.7592	503.5332	483.9176	470.9127

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	16.0949
Roof Drain (3-in. Diameter)/90% Closed	1	1.80	0.14	1.10	9.0534
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34	1.30	0.08	0.65	222.3109
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2	6.20	1.20	0.94	62.3678
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77	0.53	0.11	0.13	205.2603
Automatic Gauge Float Well/Bolted Cover, Gasketed	2	2.80	0.00	0.00	28.1661
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	70.4152

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

R510/511 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	1,758.18	3,307.83	897.19	0.00	5,963.21
1,2,4-Trimethylbenzene	0.06	9.30	0.03	0.00	9.39
Benzene	1.51	4.68	0.77	0.00	6.96
Chrysene	0.00	0.07	0.00	0.00	0.07
Cresol (-m)	0.00	0.02	0.00	0.00	0.02
Cumene	0.00	0.08	0.00	0.00	0.08
Cyclohexene	7.43	24.48	3.79	0.00	35.69
Ethylbenzene	0.16	4.94	0.08	0.00	5.17
Hexane (-n)	15.49	29.55	7.91	0.00	52.95
Naphthalene	0.00	3.03	0.00	0.00	3.03
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	1.79	19.09	0.91	0.00	21.79
Unidentified Components	1,730.92	3,181.36	883.28	0.00	5,795.56
Xylenes (mixed isomers)	0.82	31.23	0.42	0.00	32.47

ATTACHMENT C

Tank R510 NSR Balance

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572-6321

November 13, 1980

Shell Oil Company
P. O. Box 6249
Carson, CA 90749

Attention: Environmental Conservation Manager

Dear Sir:

Transmitted herewith are the following permits authorizing you to operate the described equipment: 1622 EAST SEPULVEDA BLVD, CARSON

Permit No.	Application No.	Equipment Description
M-12199	C-18847	STORAGE TANK NO. R-513
M-12200	C-18848	STORAGE TANK NO. R-512
M-12251	C-18849	STORAGE TANK NO. R-511
M-12252	C-18850	STORAGE TANK NO. R-510

Rule 206 A person granted a permit under Rule 203 shall not operate or use any equipment unless the entire permit to operate or a legible facsimile of the entire permit is affixed upon the equipment in such a manner that the permit number equipment description and the specified operating conditions are clearly visible and accessible In the event that the equipment is so constructed that the permit to operate or the legible facsimile cannot be so placed the entire permit to operate or the legible facsimile of the entire permit shall be mounted so as to be clearly visible in an accessible place within 8 meters (26 feet) of the equipment or as otherwise approved by the Air Pollution Control Officer

These permits are being issued covering your application on file at the Air Quality Management District.

Very truly yours,

Eric E. Lemke
Chief Deputy Executive Officer

EEL:HT:la
Encs.

Helen Thompson, Permit Section

Rev. 8/78 30D170

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
METROPOLITAN ZONE

ENGINEERING DIVISION - APPLICATION EMISSION DATA SHEET

[✓] P/C [✓] Basic Including Spray Booths [ ] Trade-offs DATE: 7/10/78
[✓] Rule Reduction
[ ] P/O [ ] Control Except Spray Booths [ ] Recall APPL. NO.: C-18850

NAME: SHELL OIL COMPANY

ADDRESS: 1622 EAST SEPULVEDA BLVD., CARSON 90749

[✓] Rule 213 Applicable (unit installed or permit to construct issued on or subsequent to 10/8/76).

[ ] Rule 213 Not Applicable (unit installed or permit to construct issued prior to 10/8/76, or previously exempt by Rule 219).

Emissions From This Permit Unit

(Complete for basic equipment and spray booths only)

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	4.3	—	—	—	—
Lbs/Day	103.7	—	—	—	—

Altered Permit Unit [✓] Yes [ ] No Prior Permit Number or Date Installed Without Permit PRIOR APPL'N NO'S: C-03789 (ARCO) P/C <10/8/76 C-08256 (SHELL)

(Complete for basic equipment and spray booths only)

Emissions from previous permit unit:

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	~~16.6~~	—	—	—	—
Lbs/Day	~~398.4~~	—	—	—	—

Mitigations (on premise reductions) Achieved Concurrent With This Application
(Also complete for control equipment except spray booths)

Appl. No	H/C Total		NO_x		SO_2		CO		Part.	
	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day

BACT Evaluation Not Made [✓] Made [ ] in Appl. ______ Date ______
Stationary Source (Entire Facility) Employs BACT Yes [ ] No [ ] UNKNOWN

Engineer [signature]

332-60D792-RJ

ATTACHMENT D

Rule 1401 Analysis

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	**09/10/10**
A/N:	T2640
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	64	feet
Area (For Volume Source Only)	53100	ft^2
Distance-Residential	750	meters
Distance-Commercial	175	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
So[illegible]tput capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	9.40E-03	78.11	0.0094		0.0094
P15	Chrysene	0.00E+00	228.2928	0		0
C30	Cresol mixtures	0.00E+00	108.14	0		0
E4	Ethyl benzene	1.20E-03	106.16	0.0012		0.0012
H8	Hexane (n-)	1.22E-01	86.18	0.1224		0.1224
P30	Naphthalene	5.00E-04	128.1732	0.0005		0.0005
P3	Phenol	0.00E+00	94.11	0		0
T3	Toluene (methyl benzene)	6.30E-03	92.13	0.0063		0.0063
X1	Xylenes (isomers and mixtures)	5.70E-03	106.2	0.0057		0.0057
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: T2640
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors table:

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.25	13.3
Commercial	2.6475	80.25

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	9.40E-03	9.40E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene			3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures				1	1	1	1.0000	600	
Ethyl benzene	1.20E-03	1.20E-03	8.70E-03	1	1	1	1	2000	
Hexane (n-)	1.22E-01	1.22E-01		1.0000	1.0000	1	1	7000	
Naphthalene	5.00E-04	5.00E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol				1	1	1	1	200	5800
Toluene (methyl benzene)	6.30E-03	6.30E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	5.70E-03	5.70E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	9.40E-03	9.40E-03	82.1184	0.0410592
Chrysene				
Cresol mixtures				
Ethyl benzene	1.20E-03	1.20E-03	10.4832	0.0052416
Hexane (n-)	1.22E-01	1.22E-01	1069.2864	0.5346432
Naphthalene	5.00E-04	5.00E-04	4.368	0.002184
Phenol				
Toluene (methyl benzene)	6.30E-03	6.30E-03	55.0368	0.0275184
Xylenes (isomers and mixtures)	5.70E-03	5.70E-03	49.7952	0.0248976
Total	1.46E-01	1.46E-01	1.27E+03	6.36E-01

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Attachment D

A/N: T2640

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.95E-07	6.09E-07
Chrysene		
Cresol mixtures		
Ethyl benzene	3.27E-09	6.77E-09
Hexane (n-)		
Naphthalene	1.88E-08	3.89E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**3.17E-07**	**6.55E-07**
	PASS	**PASS**

D-5

No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

$HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute\ REL$

$HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic\ REL$

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		6.87E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV			Pass	Pass
Developmental - DEV	5.94E-04	2.04E-03	Pass	Pass
Endocrine system - END		6.87E-06	Pass	Pass
Eye	3.45E-05		Pass	Pass
Hematopoietic system - HEM	5.80E-04	1.79E-03	Pass	Pass
Immune system - IMM	5.80E-04		Pass	Pass
Kidney - KID		6.87E-06	Pass	Pass
Nervous system - NS	1.37E-05	2.33E-03	Pass	Pass
Reproductive system - REP	5.94E-04		Pass	Pass
Respiratory system - RES	3.45E-05	9.70E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2640 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
	HIA - Residential									
Benzene (including benzene from gasoline)			9.62E-05		9.62E-05	9.62E-05		9.62E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol										
Toluene (methyl benzene)			2.26E-06	2.26E-06			2.26E-06	2.26E-06	2.26E-06	
Xylenes (isomers and mixtures)				3.45E-06					3.45E-06	
Total			9.84E-05	5.71E-06	9.62E-05	9.62E-05	2.26E-06	9.84E-05	5.71E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			5.80E-04		5.80E-04	5.80E-04		5.80E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol										
Toluene (methyl benzene)			1.37E-05	1.37E-05			1.37E-05	1.37E-05	1.37E-05	
Xylenes (isomers and mixtures)				2.08E-05					2.08E-05	
Total			5.94E-04	3.45E-05	5.80E-04	5.80E-04	1.37E-05	5.94E-04	3.45E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.69E-04			1.69E-04			1.69E-04			
Chrysene													
Cresol mixtures													
Ethyl benzene	6.49E-07			6.49E-07	6.49E-07				6.49E-07				
Hexane (n-)										1.89E-05			
Naphthalene												6.01E-05	
Phenol													
Toluene (methyl benzene)				2.27E-05						2.27E-05		2.27E-05	
Xylenes (isomers and mixtures)										8.80E-06		8.80E-06	
Total	6.49E-07			1.93E-04	6.49E-07		1.69E-04		6.49E-07	2.20E-04		9.16E-05	

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Attachment D

A/N: T2640 **Application deemed complete date:** 09/10/10

6b. Hazard Index Chronic (cont.)

Compound	HIC - Commercial												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.79E-03			1.79E-03			1.79E-03			
Chrysene													
Cresol mixtures													
Ethyl benzene	6.87E-06			6.87E-06	6.87E-06				6.87E-06				
Hexane (n-)										2.00E-04			
Naphthalene												6.36E-04	
Phenol													
Toluene (methyl benzene)				2.40E-04						2.40E-04		2.40E-04	
Xylenes (isomers and mixtures)										9.32E-05		9.32E-05	
Total	6.87E-06			2.04E-03	6.87E-06		1.79E-03		6.87E-06	2.33E-03		9.70E-04	

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Attachment D

Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2643
Fac:	171107

Stack Data		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	48	feet
Area (For Volume Source Only)	3000	ft^2
Distance-Residential	700	meters
Distance-Commercial	125	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
Source output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	2.40E-03	78.11	0.0024		0.0024
P15	Chrysene	0.00E+00	228.2928	0		0
C30	Cresol mixtures	0.00E+00	108.14	0		0
E4	Ethyl benzene	2.00E-04	106.16	0.0002		0.0002
H8	Hexane (n-)	3.15E-02	86.18	0.0315		0.0315
P30	Naphthalene	1.00E-04	128.1732	0.0001		0.0001
P3	Phenol	0.00E+00	94.11	0		0
T3	Toluene (methyl benzene)	1.30E-03	92.13	0.0013		0.0013
X1	Xylenes (isomers and mixtures)	9.00E-04	106.2	0.0009		0.0009
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N:	T2643
Fac:	171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.282	16.48
Commercial	4.8075	180

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	2.40E-03	2.40E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene			3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures				1	1	1	1.0000	600	
Ethyl benzene	2.00E-04	2.00E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	3.15E-02	3.15E-02		1.0000	1.0000	1	1	7000	
Naphthalene	1.00E-04	1.00E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol				1	1	1	1	200	5800
Toluene (methyl benzene)	1.30E-03	1.30E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	9.00E-04	9.00E-04		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	2.40E-03	2.40E-03	20.9664	0.0104832
Chrysene				
Cresol mixtures				
Ethyl benzene	2.00E-04	2.00E-04	1.7472	0.0008736
Hexane (n-)	3.15E-02	3.15E-02	275.184	0.137592
Naphthalene	1.00E-04	1.00E-04	0.8736	0.0004368
Phenol				
Toluene (methyl benzene)	1.30E-03	1.30E-03	11.3568	0.0056784
Xylenes (isomers and mixtures)	9.00E-04	9.00E-04	7.8624	0.0039312
Total	3.64E-02	3.64E-02	3.18E+02	1.59E-01

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Attachment D

A/N: T2643

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	8.49E-08	2.82E-07
Chrysene		
Cresol mixtures		
Ethyl benzene	6.15E-10	2.05E-09
Hexane (n-)		
Naphthalene	4.24E-09	1.41E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**8.97E-08**	**2.99E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		2.08E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV			Pass	Pass
Developmental - DEV	3.39E-04	9.24E-04	Pass	Pass
Endocrine system - END		2.08E-06	Pass	Pass
Eye	1.37E-05		Pass	Pass
Hematopoietic system - HEM	3.32E-04	8.32E-04	Pass	Pass
Immune system - IMM	3.32E-04		Pass	Pass
Kidney - KID		2.08E-06	Pass	Pass
Nervous system - NS	6.32E-06	1.04E-03	Pass	Pass
Reproductive system - REP	3.39E-04		Pass	Pass
Respiratory system - RES	1.37E-05	3.48E-04	Pass	Pass
Skin			Pass	Pass

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Attachment D

A/N: T2643 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			3.04E-05		3.04E-05	3.04E-05		3.04E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol										
Toluene (methyl benzene)			5.79E-07	5.79E-07			5.79E-07	5.79E-07	5.79E-07	
Xylenes (isomers and mixtures)				6.74E-07					6.74E-07	
Total			3.10E-05	1.25E-06	3.04E-05	3.04E-05	5.79E-07	3.10E-05	1.25E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			3.32E-04		3.32E-04	3.32E-04		3.32E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol										
Toluene (methyl benzene)			6.32E-06	6.32E-06			6.32E-06	6.32E-06	6.32E-06	
Xylenes (isomers and mixtures)				7.36E-06					7.36E-06	
Total			3.39E-04	1.37E-05	3.32E-04	3.32E-04	6.32E-06	3.39E-04	1.37E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				4.88E-05			4.88E-05			4.88E-05			
Chrysene													
Cresol mixtures													
Ethyl benzene	1.22E-07			1.22E-07	1.22E-07				1.22E-07				
Hexane (n-)										5.49E-06			
Naphthalene												1.35E-05	
Phenol													
Toluene (methyl benzene)				5.28E-06						5.28E-06		5.28E-06	
Xylenes (isomers and mixtures)										1.57E-06		1.57E-06	
Total	1.22E-07			5.42E-05	1.22E-07		4.88E-05		1.22E-07	6.11E-05		2.04E-05	

A/N: T2643 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				8.32E-04			8.32E-04			8.32E-04			
Chrysene													
Cresol mixtures													
Ethyl benzene	2.08E-06			2.08E-06	2.08E-06				2.08E-06				
Hexane (n-)										9.36E-05			
Naphthalene												2.31E-04	
Phenol													
Toluene (methyl benzene)				9.01E-05						9.01E-05		9.01E-05	
Xylenes (isomers and mixtures)										2.67E-05		2.67E-05	
Total	2.08E-06			9.24E-04	2.08E-06		8.32E-04		2.08E-06	1.04E-03		3.48E-04	

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	R510
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	650	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
Source output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	7.95E-04	78.11	0.0007945		0.0007945
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.90E-04	106.16	0.000590183		0.000590183
H8	Hexane (n-)	6.04E-03	86.18	0.006044521		0.006044521
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.49E-03	92.13	0.002487443		0.002487443
X1	Xylenes (isomers and mixtures)	3.71E-03	106.2	0.003706621		0.003706621
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R510
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors table:

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.302	15.7
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0 96
Worker	1	149	0.38

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Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	7.95E-04	7.95E-04	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.90E-04	5.90E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	6.04E-03	6.04E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.49E-03	2.49E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03		1.0000	1.0000	1	1	700	22000

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	7.95E-04	7.95E-04	6.940752	0.003470376
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.90E-04	5.90E-04	5.15583562	0.002577918
Hexane (n-)	6.04E-03	6.04E-03	52.8049315	0.026402466
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.49E-03	2.49E-03	21.7303014	0.010865151
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03	32.3810411	0.016190521
Total	1.40E-02	1.40E-02	1.22E+02	6.11E-02

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Attachment D

A/N: R510

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	3.01E-08	2.54E-07
Chrysene	3.51E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	1.94E-09	1.64E-08
Hexane (n-)		
Naphthalene	1.57E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**5.13E-08**	**4.17E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.70E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.45E-04	1.23E-03	Pass	Pass
Endocrine system - END		1.67E-05	Pass	Pass
Eye	5.04E-05		Pass	Pass
Hematopoietic system - HEM	1.31E-04	7.47E-04	Pass	Pass
Immune system - IMM	1.31E-04		Pass	Pass
Kidney - KID		1.70E-05	Pass	Pass
Nervous system - NS	1.44E-05	1.56E-03	Pass	Pass
Reproductive system - REP	1.45E-04		Pass	Pass
Respiratory system - RES	5.04E-05	2.94E-03	Pass	Pass
Skin			Pass	Pass

A/N: R510 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			9.60E-06		9.60E-06	9.60E-06		9.60E-06		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.09E-09					3.09E-09	
Toluene (methyl benzene)			1.06E-06	1.06E-06			1.06E-06	1.06E-06	1.06E-06	
Xylenes (isomers and mixtures)				2.65E-06					2.65E-06	
Total			1.07E-05	3.70E-06	9.60E-06	9.60E-06	1.06E-06	1.07E-05	3.70E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.31E-04		1.31E-04	1.31E-04		1.31E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.44E-05	1.44E-05			1.44E-05	1.44E-05	1.44E-05	
Xylenes (isomers and mixtures)				3.60E-05					3.60E-05	
Total			1.45E-04	5.04E-05	1.31E-04	1.31E-04	1.44E-05	1.45E-04	5.04E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.73E-05			1.73E-05			1.73E-05			
Chrysene													
Cresol mixtures										4.97E-09			
Ethyl benzene	3.85E-07			3.85E-07	3.85E-07				3.85E-07				
Hexane (n-)										1.13E-06			
Naphthalene												5.02E-05	
Phenol	7.45E-09		7.45E-09						7.45E-09	7.45E-09			
Toluene (methyl benzene)				1.08E-05						1.08E-05		1.08E-05	
Xylenes (isomers and mixtures)										6.92E-06		6.92E-06	
Total	3.93E-07		7.45E-09	2.85E-05	3.85E-07		1.73E-05		3.93E-07	3.62E-05		6.79E-05	

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Attachment D

A/N: R510

Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
	HIC - Commercial												
Benzene (including benzene from gasoline)				7.47E-04			7.47E-04			7.47E-04			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.67E-05			1.67E-05	1.67E-05				1.67E-05				
Hexane (n-)										4.87E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.68E-04						4.68E-04		4.68E-04	
Xylenes (isomers and mixtures)										2.99E-04		2.99E-04	
Total	1.70E-05		3.22E-07	1.23E-03	1.67E-05		7.47E-04		1.70E-05	1.56E-03		2.94E-03	

Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	R511
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	550	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible]utput capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	7.95E-04	78.11	0.0007945		0.0007945
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.90E-04	106.16	0.000590183		0.000590183
H8	Hexane (n-)	6.04E-03	86.18	0.006044521		0.006044521
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.49E-03	92.13	0.002487443		0.002487443
X1	Xylenes (isomers and mixtures)	3.71E-03	106.2	0.003706621		0.003706621
				0		
				0		
				0		
				0		
				0		
				0		
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				0		

TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R511
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.354	18.1
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	7.95E-04	7.95E-04	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.90E-04	5.90E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	6.04E-03	6.04E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.49E-03	2.49E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03		1.0000	1.0000	1	1	700	22000

4. Emission Calculations

Compound	R1 (lb/hr) uncontrolled	R2 (lb/hr) controlled	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	7.95E-04	7.95E-04	6.940752	0.003470376
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.90E-04	5.90E-04	5.15583562	0.002577918
Hexane (n-)	6.04E-03	6.04E-03	52.8049315	0.026402466
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.49E-03	2.49E-03	21.7303014	0.010865151
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03	32.3810411	0.016190521
Total	1.40E-02	1.40E-02	1.22E+02	6.11E-02

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Attachment D

A/N: R511

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	3.53E-08	2.54E-07
Chrysene	4.12E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	2.28E-09	1.64E-08
Hexane (n-)		
Naphthalene	1.84E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**6.01E-08**	**4.17E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.70E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.45E-04	1.23E-03	Pass	Pass
Endocrine system - END		1.67E-05	Pass	Pass
Eye	5.04E-05		Pass	Pass
Hematopoietic system - HEM	1.31E-04	7.47E-04	Pass	Pass
Immune system - IMM	1.31E-04		Pass	Pass
Kidney - KID		1.70E-05	Pass	Pass
Nervous system - NS	1.44E-05	1.56E-03	Pass	Pass
Reproductive system - REP	1.45E-04		Pass	Pass
Respiratory system - RES	5.04E-05	2.94E-03	Pass	Pass
Skin			Pass	Pass

A/N: R511 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.11E-05		1.11E-05	1.11E-05		1.11E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.56E-09					3.56E-09	
Toluene (methyl benzene)			1.22E-06	1.22E-06			1.22E-06	1.22E-06	1.22E-06	
Xylenes (isomers and mixtures)				3.05E-06					3.05E-06	
Total			1.23E-05	4.27E-06	1.11E-05	1.11E-05	1.22E-06	1.23E-05	4.27E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.31E-04		1.31E-04	1.31E-04		1.31E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.44E-05	1.44E-05			1.44E-05	1.44E-05	1.44E-05	
Xylenes (isomers and mixtures)				3.60E-05					3.60E-05	
Total			1.45E-04	5.04E-05	1.31E-04	1.31E-04	1.44E-05	1.45E-04	5.04E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				2.03E-05			2.03E-05			2.03E-05			
Chrysene													
Cresol mixtures										5.82E-09			
Ethyl benzene	4.52E-07			4.52E-07	4.52E-07				4.52E-07				
Hexane (n-)										1.32E-06			
Naphthalene												5.88E-05	
Phenol	8.74E-09		8.74E-09						8.74E-09	8.74E-09			
Toluene (methyl benzene)				1.27E-05						1.27E-05		1.27E-05	
Xylenes (isomers and mixtures)										8.11E-06		8.11E-06	
Total	4.60E-07		8.74E-09	3.34E-05	4.52E-07		2.03E-05		4.60E-07	4.24E-05		7.96E-05	

A/N: R511 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				7.47E-04			7.47E-04			7.47E-04			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.67E-05			1.67E-05	1.67E-05				1.67E-05				
Hexane (n-)										4.87E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.68E-04						4.68E-04		4.68E-04	
Xylenes (isomers and mixtures)										2.99E-04		2.99E-04	
Total	1.70E-05		3.22E-07	1.23E-03	1.67E-05		7.47E-04		1.70E-05	1.56E-03		2.94E-03	

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Attachment D

Janice West

From: Jeffrey Inabinet
Sent: Friday, March 29, 2013 8:44 AM
To: Janice West
Subject: RE: CEQA for Phillips 66 Carson new crude tanks

Hi Janice-

Thanks for checking in with me on this project. I have the revised document (they submitted an earlier version that indicated they were installing two tanks- now only installing one), but haven't had a chance to look at it yet. I am out of the office next week, but plan on reviewing it the following week. I just had a meeting with their consultant yesterday, so I believe they are now aware of my schedule. I'll let you know when I complete my review and we can discuss any outstanding issues.

Thanks-

Jeff

Jeff Inabinet
Air Quality Specialist
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4182
jinabinet@aqmd.gov
909.396.2453 phone
909.396.3324 fax

From: Janice West
Sent: Thursday, March 28, 2013 10:35 AM
To: Jeffrey Inabinet
Subject: CEQA for Phillips 66 Carson new crude tanks

Hi Jeff,

Any update on a rough timeframe for the CEQA analysis for the Phillips 66-Carson new crude tanks? I'm trying to figure out how much overtime I'll need so I can finish my evaluation before you finish the CEQA analysis. (we're restricted to backlog-only during regular hours). Plus, the facility is asking (politely).

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
09 396-3763
est@aqmd.gov

Janice West

From: Janice West
Sent: Thursday, March 28, 2013 10:37 AM
To: 'Matthews, John W'
Subject: RE: Carson Crude Tank Storage Capacity Permit Application Status Update Request

Hi John,

I've requested approval to work on your applications this weekend. I'll probably get back to you early next week with a better answer (I haven't yet had a chance to review your AI). I'm also checking with CEQA, but I haven't heard back from them yet.

Janice

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Wednesday, March 27, 2013 12:12 PM
To: Janice West
Subject: Carson Crude Tank Storage Capacity Permit Application Status Update Request

Janice,

Have you had a chance to review the answers to your additional information request and the revised materials that were submitted earlier this month?

Are there any items for which you still need additional information?

Assuming the negative declaration moves forward, is it safe to assume that the CEQA process will be the "rate determining step" with respect to permit issuance?

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

ENVIRONMENTAL AUDIT, INC. ®

1000-A Ortega Way, Placentia, CA 92870-7162
714/632-8521 FAX: 714/632-6754

34th ANNIVERSARY
email:dstevens@envaudit.com
mbaverman@envaudit.com

MEMORANDUM

Hand Delivered

Project No. 2778

DATE: March 12, 2013

TO: Janice West
SCAQMD

FROM: Marcia Baverman MB

RE: Revised Application Package for Tanks 2640, 2643, 510, and 511

With the removal of Tank 2641 from the proposed project, EAI has recalculated the throughputs for Tanks 2640, 510, 511, and 2643. As such, the attached SCAQMD Form E-18s have been updated to reflect the current throughput information. The Form E-GI has been revised as well and is also attached. Please contact John Matthews at Phillips 66 at 310-952-6213 or me at 714-632-8521 ext. 237, if you need further clarification.

Thanks.

MRB:pe

cc: John Matthews, Phillips 66

m:\mc\2778\2778 Janice West Cover Memo #1.doc

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) ( ) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) (●) Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: 2640 — Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics	Shell Diameter (ft.): 260 — Shell Length (ft.): ______ — Shell Height (ft.): 64 — Turnovers Per Year: 60
	Is Tank Heated? ( ) Yes (●) No — Is Tank Underground? ( ) Yes (●) No — Net Throughput (gal/year): 1260MM — Self Support Roof: (●) Yes ( ) No
	Number of Columns? 0 — Effective Column Diameter: ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1
	External Shell Condition: (●) Good ( ) Poor — Internal Shell Color: (●) Light Rust ( ) Dense Rust ( ) Gunite Lining — External Shell Color: (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer
	Average Liquid Height (ft.) (Vertical Only): 30 — Maximum Liquid Height (ft.) (Vertical Only): 60 — Working Volume (gal.) (Vertical Only): 21000000 — Actual Volume (gal.) (Vertical Only): 24150000
	Paint Condition: (●) Good ( ) Poor — Paint Color/Shade: (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer
Roof Characteristics (Floating Roof Tank)	Roof Type: ( ) Pontoon ( ) Double Deck (●) Dome Roof (Height 55.5 ft.) ( ) Cone Roof (Height ______ ft.) — Roof Fitting Category: ( ) Typical (●) Detail — Roof Height (ft.): ______
	Roof Paint Condition: (●) Good ( ) Poor — Roof Color/Shade: (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer
Deck Characteristics (Floating Roof Tank)	Deck Type: (●) Welded ( ) Bolted — Deck Fitting Characteristics: ( ) Typical ( ) Detailed (Complete Deck Seam)
	Construction: ( ) Sheet — Deck Seam Length (ft.): ______ — Deck Seam: ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide
	Construction: ( ) Panel — Deck Seam Length (ft.): ______ — Deck Seam: ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.
Tank Construction and Rim-Seal System (Floating Roof Tank)	Tank Construction: (●) Welded ( ) Riveted — Primary Seal: (●) Mechanical Shoe ( ) Liquid Mounted ( ) Vapor Mounted — Secondary Seal: (●) Rim Mounted ( ) None ( ) Shoe Mounted
Breather Vent Setting	Vacuum Setting (psig): ______ — Pressure Setting (psig): ______

* Section D of the application MUST be completed.

South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (°F): 64.31 Annual Average Minimum Temperature (°F): 54.40

Annual Average Maximum Temperature (°F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent:________ Name of Materials Dissolved:________

Concentration of Materials Dissolved:________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - __6__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - __3__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- ____ Sliding Cover, Gasketed
- ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ____ Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ____ Open
- ____ 90% Close

8. Roof Leg (3" diameter leg)
- ____ Adjustable, Pontoon Area, Ungasketed
- ____ Adjustable, Center Area, Ungasketed
- 260 Adjustable, Double-Deck Roofs
- ____ Fixed
- ____ Adjustable, Pontoon Area, Gasketed
- ____ Adjustable, Pontoon Area, Sock
- ____ Adjustable, Center Area, Gasketed
- ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ____ Adjustable
- ____ Fixed

10. Sample Pipe (24" diameter)
- ____ Slotted Pipe – Sliding Cover, Gasketed
- ____ Slotted Pipe – Sliding Cover, Ungasketed
- ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
- ____ Ungasketed, Sliding Cover, Without Float
- ____ Ungasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, Without Float
- ____ Gasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, With Pole Sleeve
- ____ Gasketed Sliding Cover, With Pole Wiper
- ____ Gasketed Sliding Cover, With Float, Wiper
- ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well
- ____ Ungasketed, Sliding Cover
- ____ Gasketed Sliding Cover
- ____ Ungasketed Sliding Cover with Sleeve
- ____ Gasketed Sliding Cover with Sleeve
- 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- 6 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav	Date: 3/12/13	Name: Marcia Baverman
	Title: Project Manager	Company Name: Environmental Audit Inc.	Phone #: (714) 632-8521 Fax #: (714) 632-6754
			Email: mbaverman@envaudit.com
Contact Info	Name: John Matthews		Phone #: (310) 952-6213 Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: John.Matthews@p66.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

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South Coast Air Quality Management District

Form 400-E-18 Storage Tank

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Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

◉ Fixed Location ○ Various Locations

Tank Type (Select ONE)	○ External Floating Roof Tank (EFRT) ○ Internal Floating Roof Tank (IFRT) ○ Horizontal Tank (HT) ○ Vertical Fixed Roof Tank (VFRT) ◉ Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: 2643 / Tank Contents/Product (include MSDS): Salt water draw from crude oil (RVP 11) storage tanks

Section B - Tank Information

Tank Characteristics	Shell Diameter (ft.): 40 / Shell Length (ft.): / Shell Height (ft.): 48 / Turnovers Per Year: 77 Is Tank Heated? ○ Yes ◉ No / Is Tank Underground? ○ Yes ◉ No / Net Throughput (gal/year): 32.256MM / Self Support Roof: ◉ Yes ○ No Number of Columns? 0 / Effective Column Diameter: ○ 9" by 7" Built Up Column - 1.1 ○ 8" Diameter Pipe - 0.7 ○ Unknown - 1 External Shell Condition: ◉ Good ○ Poor / Internal Shell Color: ◉ Light Rust ○ Dense Rust ○ Gunite Lining / External Shell Color: ◉ White/White ○ Aluminum/Specular ○ Aluminum/Diffuse ○ Gray/Light ○ Gray/Medium ○ Red/Primer Average Liquid Height (ft.) (Vertical Only): 23 / Maximum Liquid Height (ft.) (Vertical Only): 46 / Working Volume (gal.) (Vertical Only): 420000 / Actual Volume (gal.) (Vertical Only): 483000 Paint Condition: ◉ Good ○ Poor / Paint Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer
Roof Characteristics (Floating Roof Tank)	Roof Type: ○ Pontoon ○ Double Deck ◉ Dome Roof (Height 8.5 ft.) ○ Cone Roof (Height ____ ft.) / Roof Fitting Category: ○ Typical ◉ Detail / Roof Height (ft.): Roof Paint Condition: ◉ Good ○ Poor / Roof Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer
Deck Characteristics (Floating Roof Tank)	Deck Type: ◉ Welded ○ Bolted / Deck Fitting Characteristics: ○ Typical ○ Detailed (Complete Deck Seam) Construction: ○ Sheet — Deck Seam Length (ft.): ____ — Deck Seam: ○ 5 ft. wide ○ 6 ft. wide ○ 7 ft. wide ○ Panel — Deck Seam Length (ft.): ____ — Deck Seam: ○ 5 x 7.5 ft. ○ 5 x 12 ft.
Tank Construction and Rim-Seal System (Floating Roof Tank)	Tank Construction: ◉ Welded ○ Riveted / Primary Seal: ◉ Mechanical Shoe ○ Liquid Mounted ○ Vapor Mounted / Secondary Seal: ◉ Rim Mounted ○ None ○ Shoe Mounted
Breather Vent Setting	Vacuum Setting (psig): ____ / Pressure Setting (psig): ____

* Section D of the application MUST be completed.

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (˚F): 64.31 Annual Average Minimum Temperature (˚F): 54.40

Annual Average Maximum Temperature (˚F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ⦿ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ⦿ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ⦿ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:__________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Salt water with crude oil

If material is stored in a solution, supply the following information:

Name of Solvent:__________ Name of Materials Dissolved:__________

Concentration of Materials Dissolved:________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - __2__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed
2. Automatic Gauge Float Well (20" diameter well)
   - __1__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed
3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

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Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- ____ Sliding Cover, Gasketed
- ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ____ Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ____ Open
- ____ 90% Close

8. Roof Leg (3" diameter leg)
- ____ Adjustable, Pontoon Area, Ungasketed
- ____ Adjustable, Center Area, Ungasketed
- 15 Adjustable, Double-Deck Roofs
- ____ Fixed
- ____ Adjustable, Pontoon Area, Gasketed
- ____ Adjustable, Pontoon Area, Sock
- ____ Adjustable, Center Area, Gasketed
- ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ____ Adjustable
- ____ Fixed

10. Sample Pipe (24" diameter)
- ____ Slotted Pipe – Sliding Cover, Gasketed
- ____ Slotted Pipe – Sliding Cover, Ungasketed
- ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
- ____ Ungasketed, Sliding Cover, Without Float
- ____ Ungasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, Without Float
- ____ Gasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, With Pole Sleeve
- ____ Gasketed Sliding Cover, With Pole Wiper
- ____ Gasketed Sliding Cover, With Float, Wiper
- ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well
- ____ Ungasketed, Sliding Cover
- ____ Gasketed Sliding Cover
- ____ Ungasketed Sliding Cover with Sleeve
- ____ Gasketed Sliding Cover with Sleeve
- 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav… Date: 3/12/13	Name: Marcia Baverman
	Title: Project Manager Company Name: Environmental Audit Inc.	Phone #: (714) 632-8521 Fax #: (714) 632-6754 Email: mbaverman@envaudit.com
Contact Info	Name: John Matthews	Phone #: (310) 952-6213 Fax #:
	Title: Env. Engineer Company Name: Philips 66	Email: John.Matthews@p66.com

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South Coast Air Quality Management District

Form 400-E-18
Storage Tank

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Mail To:
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Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

◉ Fixed Location ○ Various Locations

Tank Type (Select ONE)	○ External Floating Roof Tank (EFRT) ○ Internal Floating Roof Tank (IFRT) ○ Horizontal Tank (HT) ○ Vertical Fixed Roof Tank (VFRT) ◉ Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: R-510 Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics

- Shell Diameter (ft.): 218
- Shell Length (ft.):
- Shell Height (ft.): 50
- Turnovers Per Year: 64
- Is Tank Heated? ○ Yes ◉ No
- Is Tank Underground? ○ Yes ◉ No
- Net Throughput (gal/year): 756MM
- Self Support Roof: ◉ Yes ○ No
- Number of Columns? 0
- Effective Column Diameter: ○ 9" by 7" Built Up Column - 1.1 ○ 8" Diameter Pipe - 0.7 ○ Unknown - 1
- External Shell Condition: ◉ Good ○ Poor
- Internal Shell Color: ◉ Light Rust ○ Dense Rust ○ Gunite Lining
- External Shell Color: ◉ White/White ○ Aluminum/Specular ○ Aluminum/Diffuse ○ Gray/Light ○ Gray/Medium ○ Red/Primer
- Average Liquid Height (ft.) (Vertical Only): 25
- Maximum Liquid Height (ft.) (Vertical Only): 43
- Working Volume (gal.) (Vertical Only): 11970000
- Actual Volume (gal.) (Vertical Only): 13440000
- Paint Condition: ◉ Good ○ Poor
- Paint Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer

Roof Characteristics (Floating Roof Tank)

- Roof Type: ○ Pontoon ○ Double Deck ◉ Dome Roof (Height 42 ft.) ○ Cone Roof (Height ____ ft.)
- Roof Fitting Category: ○ Typical ◉ Detail
- Roof Height (ft.):
- Roof Paint Condition: ◉ Good ○ Poor
- Roof Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer

Deck Characteristics (Floating Roof Tank)

- Deck Type: ◉ Welded ○ Bolted
- Deck Fitting Characteristics: ○ Typical ○ Detailed (Complete Deck Seam)

Construction:	Deck Seam Length (ft.):	Deck Seam:
○ Sheet		○ 5 ft. wide ○ 6 ft. wide ○ 7 ft. wide
○ Panel		○ 5 x 7.5 ft. ○ 5 x 12 ft.

Tank Construction and Rim-Seal System (Floating Roof Tank)

- Tank Construction: ◉ Welded ○ Riveted
- Primary Seal: ◉ Mechanical Shoe ○ Vapor Mounted ○ Liquid Mounted
- Secondary Seal: ◉ Rim Mounted ○ Shoe Mounted ○ None

Breather Vent Setting

- Vacuum Setting (psig):
- Pressure Setting (psig):

* Section D of the application MUST be completed.

South Coast Air Quality Management District

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Storage Tank

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Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (˚F): 64.31
Annual Average Minimum Temperature (˚F): 54.40
Annual Average Maximum Temperature (˚F): 74.22
Average Wind Speed (mph): 6.36
Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number: ____________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent: ____________ Name of Materials Dissolved: ____________

Concentration of Materials Dissolved: ________ % by Weight OR ________ % by Volume OR ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - __2__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - __2__ Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

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Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- 1 Sliding Cover, Gasketed
- ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ____ Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ____ Open
- ____ 90% Close

8. Roof Leg (3" diameter leg)
- ____ Adjustable, Pontoon Area, Ungasketed
- ____ Adjustable, Center Area, Ungasketed
- ____ Adjustable, Double-Deck Roofs
- ____ Fixed
- 33 Adjustable, Pontoon Area, Gasketed
- ____ Adjustable, Pontoon Area, Sock
- 75 Adjustable, Center Area, Gasketed
- ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ____ Adjustable
- ____ Fixed

10. Sample Pipe (24" diameter)
- ____ Slotted Pipe – Sliding Cover, Gasketed
- ____ Slotted Pipe – Sliding Cover, Ungasketed
- ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
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- ____ Gasketed Sliding Cover, With Pole Sleeve
- ____ Gasketed Sliding Cover, With Pole Wiper
- ____ Gasketed Sliding Cover, With Float, Wiper
- ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ **Stub Drain** (1" diameter)

13. Unslotted Guide – Pole Well
- ____ Ungasketed, Sliding Cover
- ____ Gasketed Sliding Cover
- ____ Ungasketed Sliding Cover with Sleeve
- ____ Gasketed Sliding Cover with Sleeve
- 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- 2 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav	Date: 3/13/13	Name: Marcia Baverman	
	Title: Project Manager	Company Name: EAI	Phone #: (714) 632-8521	Fax #: (714) 632-6754
			Email: mbaverman@envaudit.com	
Contact Info	Name: John Matthews		Phone #: (310) 952-6213	Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: John.Matthews@p66.com	

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Storage Tank

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◉ Fixed Location ○ Various Locations

Tank Type (Select ONE)	○ External Floating Roof Tank (EFRT) ○ Internal Floating Roof Tank (IFRT) ○ Horizontal Tank (HT) ○ Vertical Fixed Roof Tank (VFRT) ◉ Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: R-511 — Tank Contents/Product (include MSDS): Crude Oil with 11 RVP

Section B - Tank Information

Tank Characteristics	Shell Diameter (ft.): 218 — Shell Length (ft.): ____ — Shell Height (ft.): 50 — Turnovers Per Year: 64 Is Tank Heated? ○ Yes ◉ No — Is Tank Underground? ○ Yes ◉ No — Net Throughput (gal/year): 756MM — Self Support Roof: ◉ Yes ○ No Number of Columns? 0 — Effective Column Diameter: ○ 9" by 7" Built Up Column - 1.1 ○ 8" Diameter Pipe - 0.7 ○ Unknown - 1 External Shell Condition: ◉ Good ○ Poor — Internal Shell Color: ◉ Light Rust ○ Dense Rust ○ Gunite Lining — External Shell Color: ◉ White/White ○ Aluminum/Specular ○ Aluminum/Diffuse ○ Gray/Light ○ Gray/Medium ○ Red/Primer Average Liquid Height (ft.) (Vertical Only): 25 — Maximum Liquid Height (ft.) (Vertical Only): 43 — Working Volume (gal.) (Vertical Only): 11970000 — Actual Volume (gal.) (Vertical Only): 13440000 Paint Condition: ◉ Good ○ Poor — Paint Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer
Roof Characteristics (Floating Roof Tank)	Roof Type: ○ Pontoon ○ Double Deck ◉ Dome Roof (Height 42 ft.) ○ Cone Roof (Height ____ ft.) — Roof Fitting Category: ○ Typical ◉ Detail — Roof Height (ft.): ____ Roof Paint Condition: ◉ Good ○ Poor — Roof Color/Shade: ◉ White/White ○ Aluminum/Diffuse ○ Gray/Light ○ Aluminum/Specular ○ Gray/Medium ○ Red/Primer
Deck Characteristics (Floating Roof Tank)	Deck Type: ◉ Welded ○ Bolted — Deck Fitting Characteristics: ○ Typical ○ Detailed (Complete Deck Seam) Construction: ○ Sheet — Deck Seam Length (ft.): ____ — Deck Seam: ○ 5 ft. wide ○ 6 ft. wide ○ 7 ft. wide Construction: ○ Panel — Deck Seam Length (ft.): ____ — Deck Seam: ○ 5 x 7.5 ft. ○ 5 x 12 ft.
Tank Construction and Rim-Seal System (Floating Roof Tank)	Tank Construction: ◉ Welded ○ Riveted — Primary Seal: ◉ Mechanical Shoe ○ Vapor Mounted ○ Liquid Mounted — Secondary Seal: ◉ Rim Mounted ○ Shoe Mounted ○ None
Breather Vent Setting	Vacuum Setting (psig): ____ — Pressure Setting (psig): ____

* Section D of the application MUST be completed.

South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (˚F): 64.31 Annual Average Minimum Temperature (˚F): 54.40

Annual Average Maximum Temperature (˚F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:______

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent:______ Name of Materials Dissolved:______

Concentration of Materials Dissolved:______ % by Weight OR ______ % by Volume OR ______ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: 3 Unbolted Cover, Ungasketed; ____ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, UnGasketed
   - ____ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - 2 Bolted Cover, Gasketed
   - ____ Unbolted Cover, Ungasketed
   - ____ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ____ Built-Up Col - Sliding Cover, Gasketed
   - ____ Built-Up Col - Sliding Cover, Ungasketed
   - ____ Pipe Col - Flex, Fabric Sleeve Seal
   - ____ Pipe Col - Sliding Cover, Gasketed
   - ____ Pipe Col - Sliding Cover, Ungasketed

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ___ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- 1 Sliding Cover, Gasketed
- ___ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ___ Weighted Mechanical Actuation, Gasketed
- ___ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ___ Open
- ___ 90% Close

8. Roof Leg (3" diameter leg)
- ___ Adjustable, Pontoon Area, Ungasketed
- ___ Adjustable, Center Area, Ungasketed
- ___ Adjustable, Double-Deck Roofs
- ___ Fixed
- 33 Adjustable, Pontoon Area, Gasketed
- ___ Adjustable, Pontoon Area, Sock
- 75 Adjustable, Center Area, Gasketed
- ___ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ___ Adjustable
- ___ Fixed

10. Sample Pipe (24" diameter)
- ___ Slotted Pipe – Sliding Cover, Gasketed
- ___ Slotted Pipe – Sliding Cover, Ungasketed
- ___ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
- ___ Ungasketed, Sliding Cover, Without Float
- ___ Ungasketed Sliding Cover, With Float
- ___ Gasketed Sliding Cover, Without Float
- ___ Gasketed Sliding Cover, With Float
- ___ Gasketed Sliding Cover, With Pole Sleeve
- ___ Gasketed Sliding Cover, With Pole Wiper
- ___ Gasketed Sliding Cover, With Float, Wiper
- ___ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ___ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ___ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well
- ___ Ungasketed, Sliding Cover
- ___ Gasketed Sliding Cover
- ___ Ungasketed Sliding Cover with Sleeve
- ___ Gasketed Sliding Cover with Sleeve
- 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- 2 Weighted Mechanical Actuation, Gasketed
- ___ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Bav Date: 3/12/13 Title: Project Manager Company Name: Environmenal Audit Inc.	Name: Marcia Baverman Phone #: (714) 632-8521 Fax #: (714) 632-6754 Email: mbaverman@envaudit.com
Contact Info	Name: John Matthews Title: Env. Engineer Company Name: Philips 66	Phone #: (310) 952-6213 Fax #: Email: John.Matthews@p66.com

AQMD Form 400-E-GI

Philips 66 – Los Angeles Refinery Carson Plant
Facility ID No. 171109

Permit Application

Supplemental Information Package
Crude Oil Storage Capacity Project Tanks

Sections

Attachments

March 11, 2013

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1. COMPANY INFORMATION

Mailing Address
1660 W. Anaheim St.
Wilmington, CA 90744

Site Location
Carson Plant
1520 E. Sepulveda Blvd.
Carson, CA 90745

2. BACKGROUND

The Philips 66 Los Angeles Refinery Carson Plant (LARC) operates crude supply storage tanks to handle incoming crude supplies from domestic as well as various sources from the Port of Long Beach, Berth 121.

LARC currently has four 320,000 barrel (BBL) receiving tanks (285,000 BBL net working capacity) for crude. These tanks usually store three segregated crude grades at a time, which essentially limits delivery volumes to Panamax vessels (400,000 BBL capacity). For larger vessels, such as Aframax (720,000 BBL) or Suezmax (1,000,000 BBL), LARC requires two ship calls to unload the full volume of the vessels, resulting in seven to 10 days of demurrage between ship calls. Between ship calls LARC makes room in the receiving tanks to accommodate the second discharge from the larger vessel. LARC needs more tankage and capacity to accommodate the larger vessels so they can discharge their total volume in one call.

3. PROJECT DESCRIPTION

The project will increase the onsite crude storage capacity by installing one new 575,000 BBL (500,000 BBL net working capacity) domed external floating roof crude tank (Tank 2640) and geodesic domes on two of the existing crude tanks (Tank R510 (Device D394) and Tank R511(Device D395)). The project also includes the construction of a new 11,500 BBL (10,000 BBL net working capacity) domed external floating roof water draw tank (Tank 2643).

Currently, the water draw from the existing crude tanks is processed in the sour water stripper which is at times overloaded. The water draw from the existing R510 and R511 tanks and new Tank 2640 will be routed to the new water draw Tank 2643. The new 11,500 BBL water draw tank will allow LARC to treat the water at the Brine Stripper, which has excess capacity. Minor modifications are required to prepare the water draw from Tank 2643 for delivery to the Brine Stripper, consisting of the installation of new heat exchangers and a steam trim heater to raise the temperature of the water before entering the Brine Stripper.

4. EQUIPMENT LOCATION AND TANK DESCRIPTION

The new tanks and tank modifications will be located at the western boundary of LARC. Table 1 shows the specifications of the existing and proposed tanks. Please refer to the Figures 1, 2, and 3 in Attachments A for locations.

TABLE 1
Tank Specifications

Tank Number	Roof Type	Commodity Type	Working Volume (BBL)	Diameter (ft)	Height (ft)	Dome Roof (ft)
Existing 510	Pontoon	Crude Oil	285,000	218	50	42
Existing 511	Pontoon	Crude Oil	285,000	218	50	42
Modified 510	Domed	Crude Oil RVP 7	285,000	218	50	42
Modified 511	Domed	Crude Oil RVP 7	285,000	218	50	42
New Tank 2640	Domed	Crude Oil RVP 7	500,000	260	64	55.5
New Tank 2643	Domed	Water/Crude	10,000	40	48	8.5

5. OPERATING SCHEDULE

	NORMAL	MAXIMUM
Hours/Day	24	24
Days/Week	7	7
Weeks/Year	52	52

6. EMISSION CALCULATIONS

The emissions for the tanks were calculated with the EPA TANKS 4.0.9d emissions model using a crude speciation for crude oil with a Reid Vapor Pressure of 11 (true vapor pressure 11 at 77 °F, see Figure 4). The peak daily emission rate was calculated by taking the maximum monthly value and converting to a daily rate. The new 575,000 BBL tanks will use 4" legs instead of the standard 3" legs. Since there are no established emission factors for non-standard sized legs, emissions were scaled based on the difference in circumference between the 3" legs and 4" legs. The fugitive emissions from components were calculated using the SCAQMD correlation equations. The emission calculations can be found in Attachment B.

7. EVALUATION AND RULE REVIEW

The proposed Project is designed to comply with the standards contained in the applicable State and Federal Rules and Regulations. The following provides a brief summary of the applicable regulations.

STATE REGULATIONS

Rule 301 – Permit Fees

Per the requirements of SCAQMD Rule 301, the application fee for the tanks is \$12,040.21 (Schedule C – Storage Tank, with External Floating Roof). Expedited permit processing has been requested and an additional \$6,020.11 will be submitted with the permit application fee. The total application and expedited fee for the permit application is \$19,849.44.

Rule 403 – Fugitive Dust

The construction activities of the proposed project are regulated under SCAQMD Rule 403 which include requirements to minimize fugitive dust using best available control measures that include applying water or chemical stabilizers to active construction sites/unpaved roads, covering all haul vehicles, and so forth.

Rule 463 – Organic Liquid Storage

The crude storage tanks are regulated under SCAQMD Rule 463, which includes requirements to minimize fugitive VOC using best available control measures that include tanks construction standards.

Rule 466 – Pumps and Compressors

Rule 466 establishes inspection, tagging, and maintenance requirements for pumps and compressors. Pumps and compressors associated with all tanks will be included in the LARC Rule 1173 compliance program and will, therefore, comply with Rule 466.

Rule 466.1 – Valves and Flanges

Rule 466.1 establishes inspection, tagging, and maintenance requirements for valves and flanges. Valves and flanges associated with all tanks will be included in the LARC Rule 1173 monitoring program and will, therefore, comply with Rule 466.1.

Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants

The LARC currently complies with Rule 1173 and has a monitoring program for leaks. The new tanks will be incorporated into the existing plan.

Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities

Rule 1178 establishes tanks standards to control fugitive VOC emissions. The new and modified tanks associated with proposed Project will comply with Rule 1178.

Regulation XIII – New Source Review

The tanks are subject to Regulation XIII and are subject to requirements to provide emission offsets. Tanks R510 and R511 were permitted pursuant to Rule 213 with an NSR for Tank R510 identified as 103.7 lbs/day (See Attachment C). Since Tank R511 is identical to Tank R510, the total NSR balance for the tanks should be 207.4 lbs/day Pursuant to Rule 1304(c)(2) a concurrent emissions reduction can be used in lieu of providing offsets for the new equipment. As shown in Table 2, no additional offsets are required for this project.

TABLE 2
Emission Reduction Credits Summary

Tank No.	Emissions (lbs/day)
Post Project Emissions	
Modified Tank 510 Crude Tank	17.04
Modified Tank 511 Crude Tank	17.04
New Tank 2640 Crude Tank	21.24
New Tank 2643 Water Draw Tank	3.08
Fugitive Emissions	9.07
Total Project Emissions	67.47
NSR Balance for Tanks 510 and 511	207.4
Offsets Required	0

Rule 1401 – New Source Review for Toxic Air Contaminants

The tanks will store crude oil which contains chemicals listed under SCAQMD Rule 1401 and considered to be toxic air contaminants. The increase in toxic air contaminants is below the Rule 1401 screening thresholds for each of the four tanks. The Rule 1401 screening analyses are included in Attachment D.

Regulation XX - RECLAIM

The facility is subject to RECLAIM, however, the project only generates VOC emissions, which is not a RECLAIM pollutant. Therefore, no RECLAIM emissions are emitted from this project.

Regulation XXX - Title V Permits

The facility is a Title V facility. Permit modification applications are included in this application package to modify the facility Title V permit. The Title V permit modification qualifies as a significant permit revision pursuant to SCAQMD Rule 3000(b)(31)(I).

FEDERAL REGULATIONS

The federal regulations applicable to the new tanks are as follows:

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

40 CFR 61 Subpart V – National Emission Standards for Equipment Leaks (Fugitive Emission Sources)

40 CRF 61 subpart FF – National Emission Standards for Benzene Waste Operations

40 CFR 63 Subpart H – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

The federal regulations, while not identical to the state regulations, are similar to state regulations. The new and modified tanks are designed to comply with BACT requirements, the SCAQMD rules and regulations, and federal regulations. Therefore, the new and modified tanks are expected to comply with applicable subparts of the federal regulations.

8. PROPOSED PERMIT CONDITIONS

Below are the proposed permit conditions for throughput and monitoring of the tanks. These conditions should replace condition C1.17 for existing Tanks 510 and 511, and should read:

> *The operator shall limit the throughput to no more than 1,500,000 barrel(s) in any one calendar month.*
>
> *The operator shall calculate the throughput, in barrels, by the following equation:*
>
> > *0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.*
>
> *The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.*

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

The conditions for new Tank 2640 should read:

The operator shall limit the throughput to no more than 2,500,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

The conditions for new Tanks 2643 should read:

The operator shall limit the throughput to no more than 64,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

9. CONFIDENTIALITY

Certain information supplied on the attached sheets concerning process operating conditions, material balances, and process descriptions constitutes confidential and proprietary information under Government Code Section 6254.7. Philips 66 justifies classification of such data as trade secrets because the information contains production data and operating procedures, and therefore would potentially release competitively sensitive information, which would be of considerable value to competitors. Therefore, we request that all such data be handled in confidence.

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ATTACHMENT A

Figures

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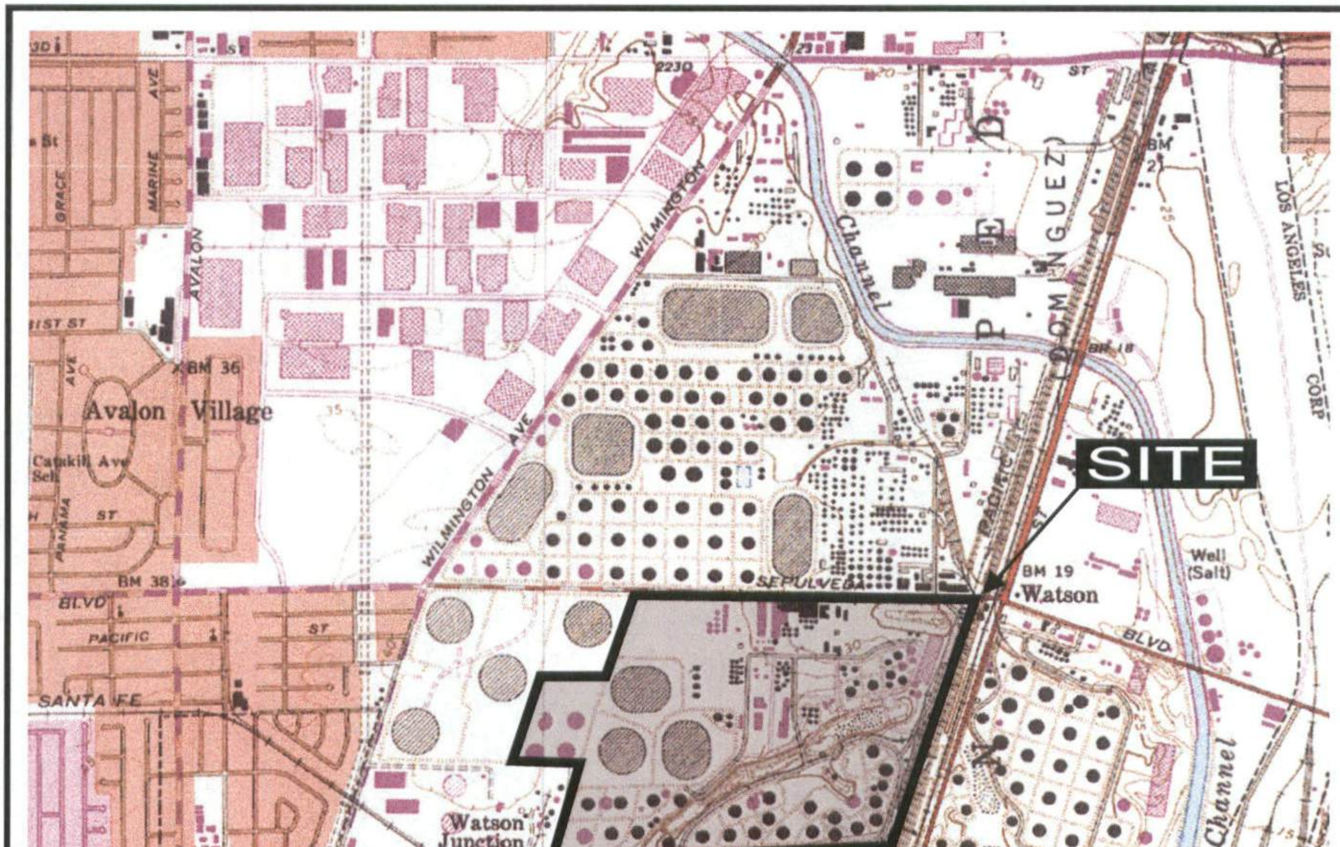

Environmental Audit, Inc.

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SITE LOCATION MAP
Phillips 66 Los Angeles Refinery
Carson Plant

Project No. 2778

Figure 1

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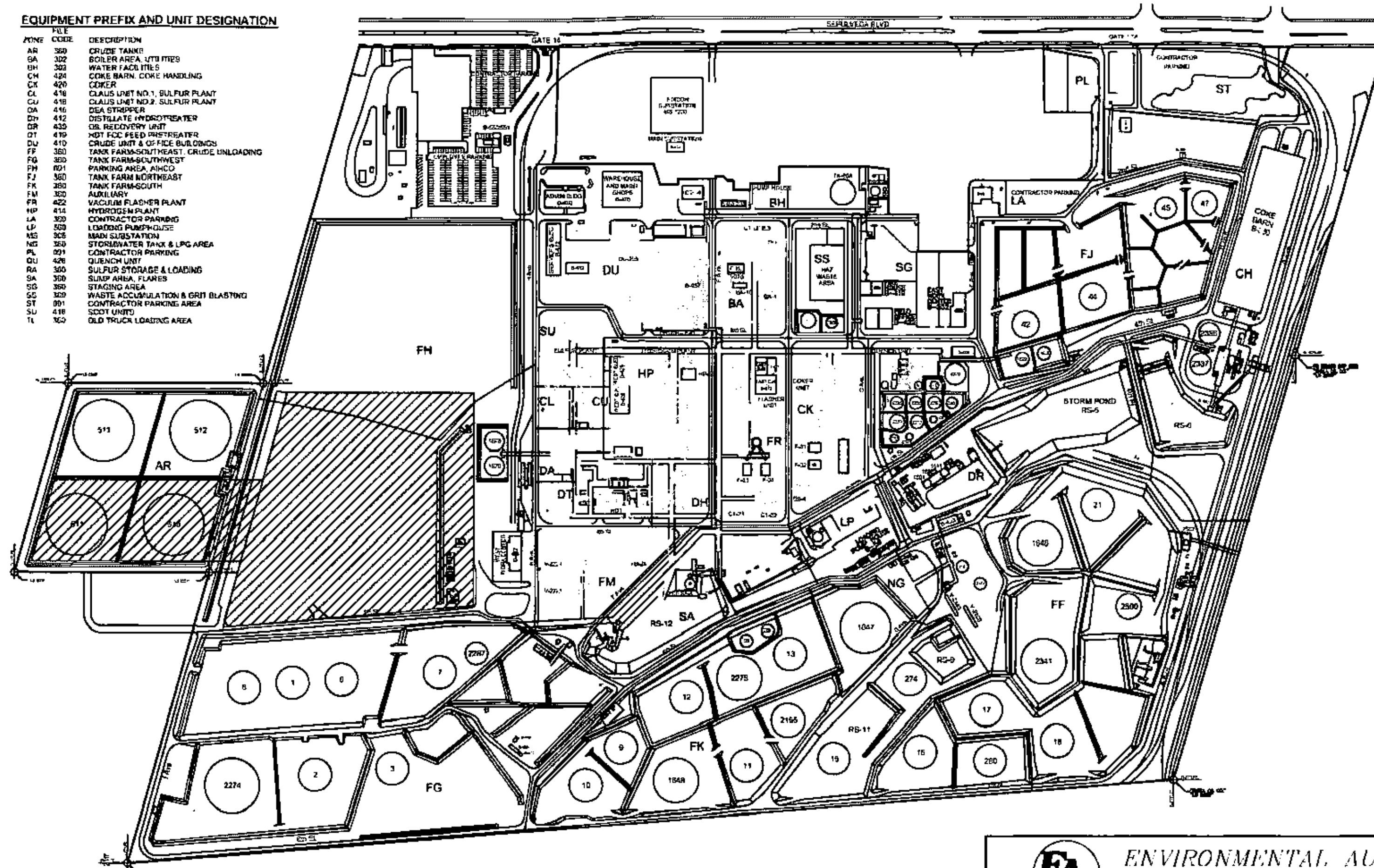
EQUIPMENT PREFIX AND UNIT DESIGNATION

ZONE	FILE CODE	DESCRIPTION
AR	360	CRUDE TANKS
BA	302	BOILER AREA, UTILITIES
BH	303	WATER FACILITIES
CH	424	COKE BARN, COKE HANDLING
CK	420	COKER
CL	418	CLAUS UNIT NO.1, SULFUR PLANT
CU	418	CLAUS UNIT NO.2, SULFUR PLANT
DA	416	DEA STRIPPER
DH	412	DISTILLATE HYDROTREATER
DR	433	OIL RECOVERY UNIT
DT	419	HDT FCC FEED PRETREATER
DU	410	CRUDE UNIT & OFFICE BUILDINGS
FF	360	TANK FARM-SOUTHEAST, CRUDE UNLOADING
FG	360	TANK FARM-SOUTHWEST
FH	001	PARKING AREA, AIHCO
FJ	360	TANK FARM NORTHEAST
FK	360	TANK FARM-SOUTH
FM	360	AUXILIARY
FR	422	VACUUM FLASHER PLANT
HP	414	HYDROGEN PLANT
LA	320	CONTRACTOR PARKING
LP	560	LOADING PUMPHOUSE
MS	905	MAIN SUBSTATION
NG	360	STORMWATER TANK & LPG AREA
PL	001	CONTRACTOR PARKING
QU	426	QUENCH UNIT
RA	300	SULFUR STORAGE & LOADING
SA	300	SUMP AREA, FLARES
SG	360	STAGING AREA
SS	320	WASTE ACCUMULATION & GRIT BLASTING
ST	001	CONTRACTOR PARKING AREA
SU	418	SCOT UNITS
TL	360	OLD TRUCK LOADING AREA



LEGEND:

(13) NUMBERS IN AND AROUND OBJECTS REPRESENT INDIVIDUAL TANK NUMBERS

PROPOSED PROJECT AREA

NORTH

0 400'

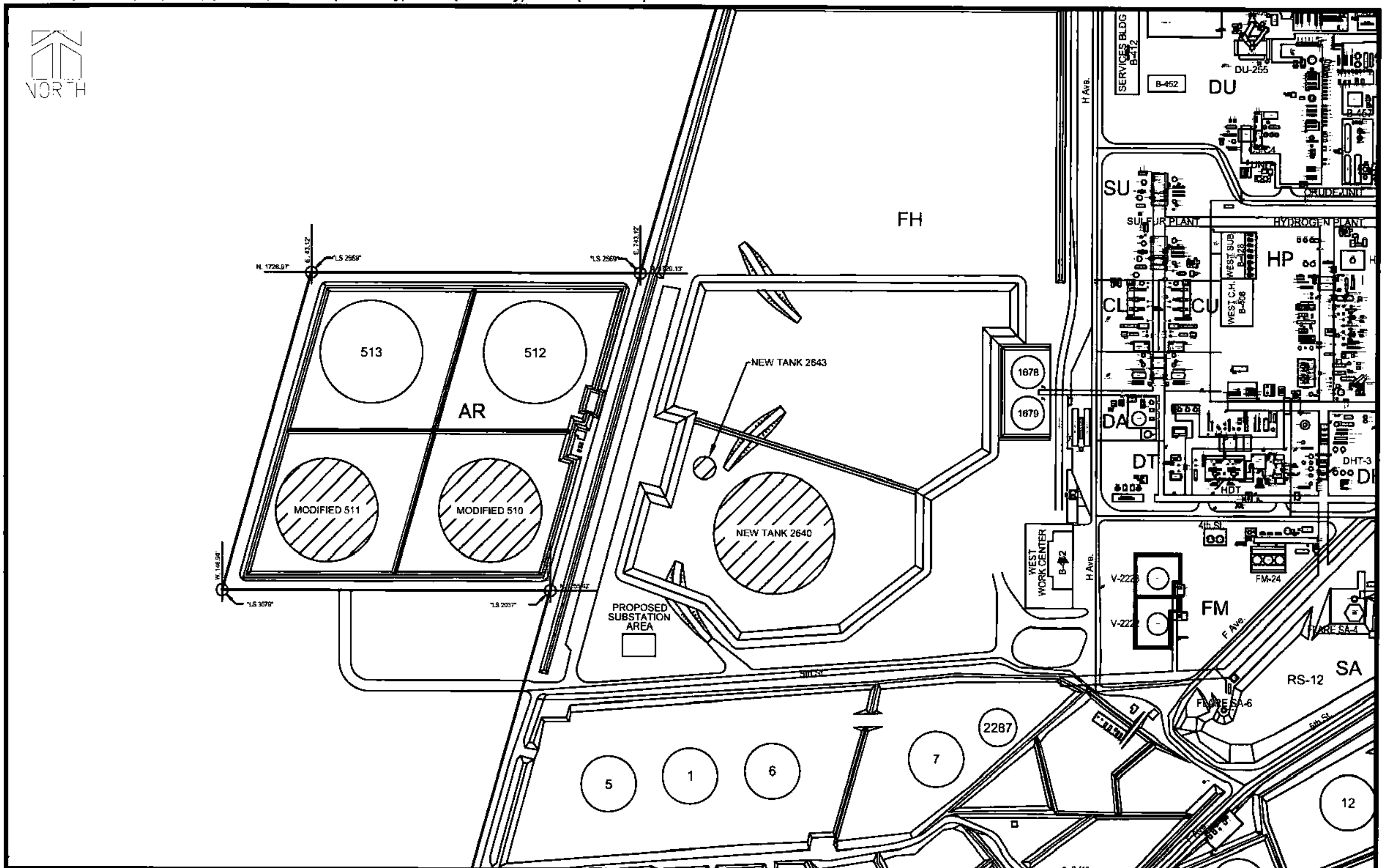
SCALE

ENVIRONMENTAL AUDIT, INC.

1000-A ORTEGA WAY • PLACENTIA, CA 92870-7125
714/632-8521 • FAX: 714/632-6754

SITE PLAN - PHILLIPS 66 LOS ANGELES REFINERY

DRAWN BY M.B.	DATE CREATED 11/19/03	CARSON PLANT
CHECKED DBS	LAST REV 06/11/12	1520 E. SEPULVEDA BLVD.
SIZE 17x11		Carson, California
FILE NAME I:\2778\Site Plan Carson Plant (rev.2)		**Figure 2**



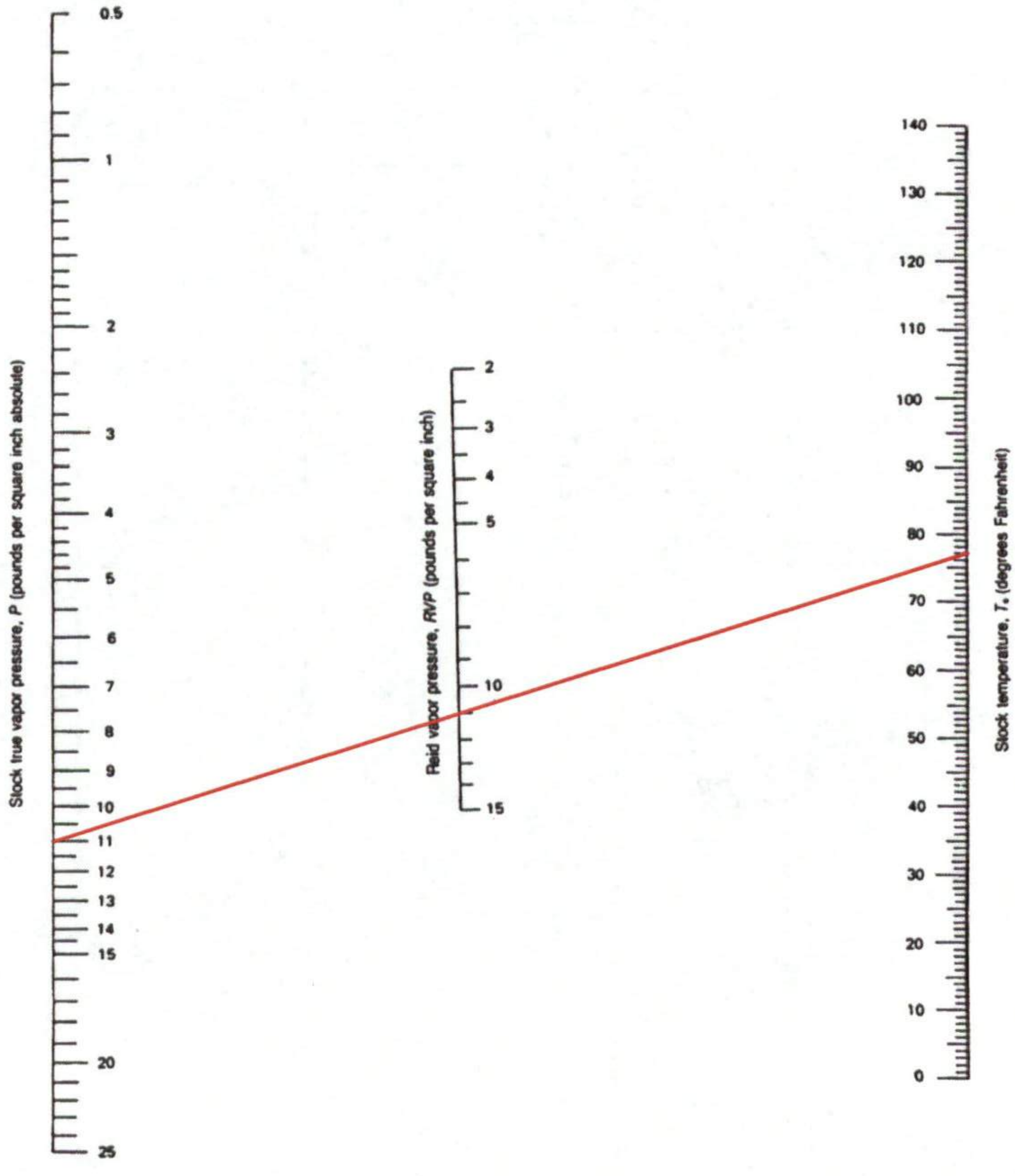
Environmental Audit, Inc.

0 300'

PROPOSED PROJECT PLAN
Phillips 66 Los Angeles Refinery
Carson Plant

Project No. 2778

Figure 3



True vapor pressure of crude oils with a Reid vapor pressure of 2 to 15 pounds per square inch.

SOURCE: AP42 Figure 7.1-13a (November 2006)

Environmental Audit, Inc.

Nomograph of Crude Oil Vapor Pressure

ATTACHMENT B

Emission Calculations

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Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2640**

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm): Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Correlation Equation (CE) Factor (500 ppm): Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Correlation Equation (CE) Factor (500 ppm): Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	190	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	14	4.55	0	63.64
		Light Liquid (4)	0	0	83	4.55	0	377.30
		Heavy Liquid (5)	0	0		4.55	0	-
		> 8 inches	0	0			0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	5	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	2	46.83	0	
Compressors		Gas / Vapor	0	0		9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	258	6.99	-	1,803.47
Connectors		All	0	0	134	2.86	-	383.43
Pressure Relief Valves		All	0	0	6		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	7	9.09	-	
Total Emissions		lb/year					-	2,628
		lbs/day					0	7.20

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2643**

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm): Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Correlation Equation (CE) Factor (500 ppm): Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Correlation Equation (CE) Factor (500 ppm): Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	61	0.00	0	0
	SCAQMD	Gas / Vapor	0	0	0	4.55	0	-
	Approved	Light Liquid (4)	0	0	16	4.55	0	72.73
	I&M Program	Heavy Liquid (5)	0	0	0	4.55	0	-
		> 8 inches	0	0	0		0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	0	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	0	46.83	0	
Compressors		Gas / Vapor	0	0	0	9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	79	6.99	-	552.22
Connectors		All	0	0	20	2.86	-	57.23
Pressure Relief Valves		All	0	0	0		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	1	9.09	-	
Total Emissions		lb/year					-	682
		lbs/day					0	1.87

-1 Any component currently installed prior to the modification.
-2 Any component to be removed due to modification.
-3 Any new component proposed to be installed due to the modification, this also includes new components to be installed to replace existing components.
-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF
-5 Heavy Liquid streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.
-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Fugitive Component Emissions

Chemical	Crude Vapor Wt%	Tank 2640 Emissions lb/yr	Tank 2640 Emissions lb/day	Tank 2640 Emissions lb/hr	Tank 2643 Emissions lb/yr	Tank 2643 Emissions lb/day	Tank 2643 Emissions lb/hr
Benzene	2.83	7.44E+01	0.20	8.50E-03	19.33	0.05	2.21E-03
PACs (Chrysene)	0.00	3.56E-05	0.00	4.06E-09	9.24E-06	0.00	1.06E-09
Cresol (mixed isomers)	0.00	4.28E-05	0.00	4.89E-09	1.11E-05	0.00	1.27E-09
Ethylbenzene	0.13	3.29E+00	0.01	3.76E-04	8.55E-01	0.00	9.76E-05
n-Hexane	38.55	1012.95	2.78	1.16E-01	262.96	0.72	3.00E-02
Naphthalene	0.00	2.26E-02	0.00	2.58E-06	5.87E-03	0.00	6.71E-07
Phenol	0.00	1.02E-04	0.00	1.16E-08	2.64E-05	0.00	3.01E-09
Toluene	1.01	2.66E+01	0.07	3.04E-03	6.90	0.02	7.88E-04
Xylene (mixed isomers)	0.19	5.09E+00	0.01	5.81E-04	1.32E+00	0.00	1.51E-04
Cumene	0.00	7.03E-03	0.00	8.02E-07	0.00	0.00	2.08E-07
Cyclohexane	19.14	503.08	1.38	5.74E-02	130.60	0.36	1.49E-02
1,2,4-Trimethylbenzene	0.01	3.28E-01	0.00	3.74E-05	8.51E-02	0.00	9.71E-06
Total VOC	100.00	2.63E+03	7.20	3.00E-01	682.18	1.87	7.79E-02

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Tank Working Loss Emissions

	Tank 2640[1]			Tank 2643			Tank R510/R511		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	8.99	0.0246	1.03E-03	1.36	0.0037	1.55E-04	6.96	0.0191	7.945E-04
PACs (Chrysene)	0.09	0.0002	1.03E-05	0.02	0.0001	2.28E-06	0.07	0.0002	7.991E-06
Cresol (mixed isomers)	0.03	0.0001	3.42E-06	-	-	0.00E+00	0.02	0.0001	2.283E-06
Ethylbenzene	7.17	0.0197	8.19E-04	1.18	0.0032	1.35E-04	5.17	0.0142	5.902E-04
n-Hexane	66.34	0.1818	7.57E-03	9.68	0.0265	1.11E-03	52.95	0.1451	6.045E-03
Naphthalene	4.24	0.0116	4.84E-04	0.71	0.0019	8.11E-05	3.03	0.0083	3.459E-04
Phenol	0.01	0.0000	1.14E-06	-	-	0.00E+00	0.01	0.0000	1.142E-06
Toluene	29.63	0.0812	3.38E-03	4.77	0.0131	5.45E-04	21.79	0.0597	2.487E-03
Xylene (mixed isomers)	45.09	0.1235	5.15E-03	7.43	0.0204	8.48E-04	32.47	0.0890	3.707E-03
Cumene	0.12	0.0003	1.37E-05	0.02	0.0001	2.28E-06	0.08	0.0002	9.132E-06
Cyclohexane	46.25	0.1267	5.28E-03	7.04	0.0193	8.04E-04	35.69	0.0978	4.074E-03
1,2,4-Trimethylbenzene	13.13	0.0360	1.50E-03	2.18	0.0060	2.49E-04	9.39	0.0257	1.072E-03
Total VOC	7,463.99	20.4493	8.52E-01	1087.84	2.9804	1.24E-01	5963.21	16.3376	6.807E-01

(1) Tank leg emissions scaled for 4" legs.

Attachment B
Emissions Calculations

Philips 66 Carson Plant
Total Tank Operational Emissions

Chemical	Tank 2640 Emissions lb/yr	Tank 2640 Emissions lb/day	Tank 2640 Emissions lb/hr	Tank 2643 Emissions lb/yr	Tank 2643 Emissions lb/day	Tank 2643 Emissions lb/hr
Benzene	83.43	0.2286	0.0095	20.69	0.0567	0.0024
PACs (Chrysene)	0.09	0.0002	0.0000	0.02	0.0001	0.0000
Cresol (mixed isomers)	0.03	0.0001	0.0000	0.00	0.0000	0.0000
Ethylbenzene	10.47	0.0287	0.0012	2.03	0.0056	0.0002
n-Hexane	1,079.29	2.9570	0.1232	272.64	0.7470	0.0311
Naphthalene	4.26	0.0117	0.0005	0.72	0.0020	0.0001
Phenol	0.01	0.0000	0.0000	0.00	0.0000	0.0000
Toluene	56.22	0.1540	0.0064	11.67	0.0320	0.0013
Xylene (mixed isomers)	50.18	0.1375	0.0057	8.75	0.0240	0.0010
Cumene	0.13	0.0003	0.0000	0.02	0.0001	0.0000
Cyclohexane	549.33	1.5050	0.0627	137.64	0.3771	0.0157
1,2,4-Trimethylbenzene	13.46	0.0369	0.0015	2.27	0.0062	0.0003
Total VOC	10,091.82	27.6488	1.1520	1,770.02	4.8494	0.2021

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2640 legged
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity)

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,000,000.00
Turnovers:	60.00

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	260
Automatic Gauge Float Well/Bolted Cover, Gasketed	3
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2640 legged - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene isopropyl benzene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

B-7

Attachment B

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

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Attachment B

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2640 legged - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	57.6988	59.1515	60.6795	63.7603	66.4370	69.5218	73.9825	74.6934	71.7943	67.2977	61.5048	57.6642
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid												
Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673
Net Throughput (gal/mo.):	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	124.1523	127.2782	130.5660	137.1950	142.9545	149.5922	159.1904	160.7200	154.4819	144.8065	132.3418	124.0778
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	568.1184	572.6970	577.5129	587.2226	595.6589	605.3813	619.4401	621.6807	612.5435	598.3716	580.1140	568.0093

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6	6.20	1.20	0.94	187.1033
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	70.4152
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	260	0.82	0.53	0.14	1,072.3230
Automatic Gauge Float Well/Bolted Cover, Gasketed	3	2.80	0.00	0.00	42.2491
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	32.1898
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608

TANKS 4.0.9d
Emissions Report - Detail Format

Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640 legged - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	784.19	4,635.21	1,687.36	0.00	7,106.75
1,2,4-Trimethylbenzene	0.03	13.04	0.05	0.00	13.12
Benzene	0.68	6.55	1.45	0.00	8.68
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.12
Cyclohexene	3.31	34.30	7.13	0.00	44.74
Ethylbenzene	0.07	6.92	0.15	0.00	7.14
Hexane (-n)	6.91	41.41	14.87	0.00	63.19
Naphthalene	0.00	4.24	0.00	0.00	4.24
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.80	26.76	1.72	0.00	29.27
Unidentified Components	772.03	4,457.98	1,661.19	0.00	6,891.20
Xylenes (mixed isomers)	0.37	43.76	0.79	0.00	44.92

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2640 legless
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity) - Legless

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,000,000.00
Turnovers:	60.00

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

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Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Attachment B

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Automatic Gauge Float Well/Bolted Cover, Gasketed	3
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2640 legless - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

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Attachment B

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

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Attachment B

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2640 legless - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	57.6988	59.1515	60.6795	63.7603	66.4370	69.5218	73.9825	74.6934	71.7943	67.2977	61.5048	57.6642
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673	386.2673
Net Throughput (gal/mo.):	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000	105,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	45.2973	46.4377	47.6373	50.0559	52.1573	54.5791	58.0810	58.6391	56.3631	52.8330	48.2852	45.2701
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	489.2634	491.8566	494.5842	500.0835	504.8616	510.3682	518.3308	519.5997	514.4247	506.3980	496.0574	489.2016

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6	6.20	1.20	0.94	187.1033
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	70.4152
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Automatic Gauge Float Well/Bolted Cover, Gasketed	3	2.80	0.00	0.00	42.2491
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	32.1898
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608

TANKS 4.0.9d
Emissions Report - Detail Format

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Attachment B

Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640 legless - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	784.19	4,635.21	615.64	0.00	6,035.03
1,2,4-Trimethylbenzene	0.03	13.04	0.02	0.00	13.08
Benzene	0.68	6.55	0.53	0.00	7.76
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.12
Cyclohexene	3.31	34.30	2.60	0.00	40.21
Ethylbenzene	0.07	6.92	0.05	0.00	7.04
Hexane (-n)	6.91	41.41	5.43	0.00	53.74
Naphthalene	0.00	4.24	0.00	0.00	4.24
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.80	26.76	0.63	0.00	28.18
Unidentified Components	772.03	4,457.98	606.09	0.00	5,836.10
Xylenes (mixed isomers)	0.37	43.76	0.29	0.00	44.42

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	T2643
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	10000bbl (working capacity) domed water surge tank

Tank Dimensions

Diameter (ft):	40.00
Volume (gallons):	420,000.00
Turnovers:	76.80

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	15

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

T2643 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0952	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0226	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0986	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56

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Attachment B

Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

T2643 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	8.8767	9.1002	9.3353	9.8093	10.2211	10.6957	11.3819	11.4913	11.0453	10.3535	9.4623	8.8714
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749
Net Throughput (gal/mo.):	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Roof Fitting Losses (lb):	14.4136	14.7765	15.1582	15.9278	16.5965	17.3671	18.4814	18.6590	17.9348	16.8115	15.3644	14.4050
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	87.5652	88.1516	88.7684	90.0120	91.0924	92.3376	94.1382	94.4251	93.2549	91.4399	89.1015	87.5513

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	16.0949
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	14.0830
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	31.1839
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	70.4152
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	15	0.82	0.53	0.14	61.8648

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

T2643 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	120.64	771.30	195.90	0.00	1,087.84
1,2,4-Trimethylbenzene	0.00	2.17	0.01	0.00	2.18
Benzene	0.10	1.09	0.17	0.00	1.36
Chrysene	0.00	0.02	0.00	0.00	0.02
Cresol (-m)	0.00	0.00	0.00	0.00	0.00
Cumene	0.00	0.02	0.00	0.00	0.02
Cyclohexene	0.51	5.71	0.83	0.00	7.04
Ethylbenzene	0.01	1.15	0.02	0.00	1.18
Hexane (-n)	1.06	6.89	1.73	0.00	9.68
Naphthalene	0.00	0.71	0.00	0.00	0.71
Phenol	0.00	0.00	0.00	0.00	0.00
Toluene	0.12	4.45	0.20	0.00	4.77
Unidentified Components	118.77	741.81	192.86	0.00	1,053.44
Xylenes (mixed isomers)	0.06	7.28	0.09	0.00	7.43

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	R510/511
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	285000 bbl tank (working capacity)

Tank Dimensions

Diameter (ft):	218.60
Volume (gallons):	11,970,000.00
Turnovers:	63.16

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Pontoon
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Shoe-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Roof Drain (3-in. Diameter)/90% Closed	1
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77
Automatic Gauge Float Well/Bolted Cover, Gasketed	2
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

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Attachment B

Liquid Contents of Storage Tank

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP11)	Jan	61.79	56.79	66.79	64.33	8.7413	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4580	N/A	N/A	49.6923	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Feb	62.78	57.67	67.88	64.33	8.8800	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0085	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.6072	N/A	N/A	49.6889	0.9618	0.9851	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Mar	63.78	58.57	68.99	64.33	9.0228	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.7607	N/A	N/A	49.6854	0.9618	0.9850	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Apr	65.70	59.89	71.51	64.33	9.3013	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777

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Attachment B

Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0087	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.0602	N/A	N/A	49.6787	0.9618	0.9847	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	May	67.27	61.79	72.76	64.33	9.5335	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0042	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3098	N/A	N/A	49.6732	0.9618	0.9844	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jun	68.98	63.35	74.61	64.33	9.7902	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0090	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.5857	N/A	N/A	49.6671	0.9618	0.9841	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Jul	71.26	65.04	77.47	64.33	10.1419	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.9635	N/A	N/A	49.6589	0.9618	0.9837	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Aug	71.60	65.63	77.58	64.33	10.1959	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0092	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						11.0215	N/A	N/A	49.6577	0.9618	0.9837	215.18	

Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Sep	70.17	64.65	75.68	64.33	9.9722	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0044	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0091	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0011	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.7812	N/A	N/A	49.6629	0.9618	0.9839	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Oct	67.76	62.48	73.04	64.33	9.6062	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0009	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0043	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0089	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						10.3880	N/A	N/A	49.6715	0.9618	0.9843	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0005	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Nov	64.31	59.22	69.40	64.33	9.0986	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0041	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0086	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0010	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.8423	N/A	N/A	49.6836	0.9618	0.9849	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP11)	Dec	61.76	56.83	66.70	64.33	8.7379	N/A	N/A	50.0000			205.00	Option 4: RVP=11
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0000	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0008	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0040	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0084	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0009	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						9.4544	N/A	N/A	49.6924	0.9618	0.9853	215.18	
Xylenes (mixed isomers)						0.0961	N/A	N/A	106.1700	0.0094	0.0004	106.17	Option 2: A=7.009, B=1462.266, C=215.11

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format

Detail Calculations (AP-42)

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	129.3637	132.6208	136.0466	142.9539	148.9552	155.8714	165.8725	167.4663	160.9664	150.8849	137.8970	129.2861
Seal Factor A (lb-mole/ft-yr):	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	8.7413	8.8800	9.0228	9.3013	9.5335	9.7902	10.1419	10.1959	9.9722	9.6062	9.0986	8.7379
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528
Net Throughput (gal/mo.):	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Roof Fitting Losses (lb):	66.0133	67.6754	69.4236	72.9483	76.0107	79.5401	84.6435	85.4569	82.1400	76.9955	70.3678	65.9738
Value of Vapor Pressure Function:	0.2219	0.2275	0.2334	0.2452	0.2555	0.2674	0.2845	0.2873	0.2761	0.2588	0.2366	0.2218
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	471.0298	475.9490	481.1230	491.5550	500.6187	511.0643	526.1688	528.5760	518.7592	503.5332	483.9176	470.9127

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	16.0949
Roof Drain (3-in. Diameter)/90% Closed	1	1.80	0.14	1.10	9.0534
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34	1.30	0.08	0.65	222.3109
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	2.3639
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2	6.20	1.20	0.94	62.3678
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	281.6608
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77	0.53	0.11	0.13	205.2603
Automatic Gauge Float Well/Bolted Cover, Gasketed	2	2.80	0.00	0.00	28.1661
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	70.4152

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

R510/511 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP11)	1,758.18	3,307.83	897.19	0.00	5,963.21
1,2,4-Trimethylbenzene	0.06	9.30	0.03	0.00	9.39
Benzene	1.51	4.68	0.77	0.00	6.96
Chrysene	0.00	0.07	0.00	0.00	0.07
Cresol (-m)	0.00	0.02	0.00	0.00	0.02
Cumene	0.00	0.08	0.00	0.00	0.08
Cyclohexene	7.43	24.48	3.79	0.00	35.69
Ethylbenzene	0.16	4.94	0.08	0.00	5.17
Hexane (-n)	15.49	29.55	7.91	0.00	52.95
Naphthalene	0.00	3.03	0.00	0.00	3.03
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	1.79	19.09	0.91	0.00	21.79
Unidentified Components	1,730.92	3,181.36	883.28	0.00	5,795.56
Xylenes (mixed isomers)	0.82	31.23	0.42	0.00	32.47

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ATTACHMENT C

Tank R510 NSR Balance

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572-6321

November 13, 1980

Shell Oil Company
P. O. Box 6249
Carson, CA 90749

Attention: Environmental Conservation Manager

Dear Sir:

Transmitted herewith are the following permits authorizing you to operate the described equipment: 1622 EAST SEPULVEDA BLVD, CARSON

Permit No.	Application No.	Equipment Description
M-12199	C-18847	STORAGE TANK NO. R-513
M-12200	C-18848	STORAGE TANK NO. R-512
M-12251	C-18849	STORAGE TANK NO. R-511
M-12252	C-18850	STORAGE TANK NO. R-510

Rule 206 A person granted a permit under Rule 203 shall not operate or use any equipment unless the entire permit to operate or a legible facsimile of the entire permit is affixed upon the equipment in such a manner that the permit number, equipment description, and the specified operating conditions are clearly visible and accessible. In the event that the equipment is so constructed that the permit to operate or the legible facsimile cannot be so placed, the entire permit to operate or the legible facsimile of the entire permit shall be mounted so as to be clearly visible in an accessible place within 8 meters (26 feet) of the equipment or as otherwise approved by the Air Pollution Control Officer.

These permits are being issued covering your application on file at the Air Quality Management District.

Very truly yours,

Eric E. Lemke
Chief Deputy Executive Officer

EEL:HT:la
Encs.

Helen Thompson, Permit Section

Rev. 8/78 30D170

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
METROPOLITAN ZONE

ENGINEERING DIVISION - APPLICATION EMISSION DATA SHEET

[✓] P/C   [✓] Basic Including Spray Booths   [ ] Trade-offs   DATE: 7/10/78
[✓] Rule Reduction
[ ] P/O   [ ] Control Except Spray Booths   [ ] Recall   APPL. NO.: C-18850

NAME: SHELL OIL COMPANY

ADDRESS: 1622 EAST SEPULVEDA BLVD., CARSON 90749

[✓] Rule 213 Applicable (unit installed or permit to construct issued on or subsequent to 10/8/76).

[ ] Rule 213 Not Applicable (unit installed or permit to construct issued prior to 10/8/76, or previously exempt by Rule 219).

Emissions From This Permit Unit

(Complete for basic equipment and spray booths only)

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	4.3	—	—	—	—
Lbs/Day	103.7	—	—	—	—

Altered Permit Unit [✓] Yes [ ] No   Prior Permit Number or Date Installed Without Permit PRIOR APPL'N NO'S: C-03789 (ARCO) P/C < 10/8/76 C-08256 (SHELL)

(Complete for basic equipment and spray booths only)
Emissions from previous permit unit:

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	~~16.6~~	—	—	—	—
Lbs/Day	~~398.4~~	—	—	—	—

Mitigations (on premise reductions) Achieved Concurrent With This Application
(Also complete for control equipment except spray booths)

Appl. No	H/C Total		NO_x		SO_2		CO		Part.	
	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day

BACT Evaluation Not Made [✓] Made [ ] in Appl.________ Date________
Stationary Source (Entire Facility) Employs BACT Yes [ ] No [ ] UNKNOWN

Engineer [signature]

332-600792-R1

ATTACHMENT D

Rule 1401 Analysis

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2640
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	64	feet
Area (For Volume Source Only)	53100	ft^2
Distance-Residential	750	meters
Distance-Commercial	175	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible]e output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	9.52E-03	78.11	0.009524333		0.009524333
P15	Chrysene	1.03E-05	228.2928	1.0278E-05		1.0278E-05
C30	Cresol mixtures	3.43E-06	108.14	3.42955E-06		3.42955E-06
E4	Ethyl benzene	1.19E-03	106.16	0.001194836		0.001194836
H8	Hexane (n-)	1.23E-01	86.18	0.123207131		0.123207131
P30	Naphthalene	4.87E-04	128.1732	0.000486601		0.000486601
P3	Phenol	1.15E-06	94.11	1.15315E-06		1.15315E-06
T3	Toluene (methyl benzene)	6.42E-03	92.13	0.006418356		0.006418356
X1	Xylenes (isomers and mixtures)	5.73E-03	106.2	0.005727946		0.005727946
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N:	T2640
Fac:	171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.25	13.3
Commercial	2.6475	80.25

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

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Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	9.52E-03	9.52E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	1.03E-05	1.03E-05	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	3.43E-06	3.43E-06		1	1	1	1.0000	600	
Ethyl benzene	1.19E-03	1.19E-03	8.70E-03	1	1	1	1	2000	
Hexane (n-)	1.23E-01	1.23E-01		1.0000	1.0000	1	1	7000	
Naphthalene	4.87E-04	4.87E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.15E-06	1.15E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	6.42E-03	6.42E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	5.73E-03	5.73E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	9.52E-03	9.52E-03	83.20457	0.041602285
Chrysene	1.03E-05	1.03E-05	0.08978893	4.48945E-05
Cresol mixtures	3.43E-06	3.43E-06	0.02996053	1.49803E-05
Ethyl benzene	1.19E-03	1.19E-03	10.4380882	0.005219044
Hexane (n-)	1.23E-01	1.23E-01	1076.3375	0.538168749
Naphthalene	4.87E-04	4.87E-04	4.25094833	0.002125474
Phenol	1.15E-06	1.15E-06	0.01007388	5.03694E-06
Toluene (methyl benzene)	6.42E-03	6.42E-03	56.0707589	0.028035379
Xylenes (isomers and mixtures)	5.73E-03	5.73E-03	50.0393323	0.025019666
Total	1.47E-01	1.47E-01	1.28E+03	6.40E-01

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Attachment D

A/N: T2640

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.99E-07	6.17E-07
Chrysene	3.74E-09	3.80E-09
Cresol mixtures		
Ethyl benzene	3.26E-09	6.74E-09
Hexane (n-)		
Naphthalene	1.83E-08	3.79E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**3.24E-07**	**6.66E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		6.91E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		6.60E-08	Pass	Pass
Developmental - DEV	6.02E-04	2.07E-03	Pass	Pass
Endocrine system - END		6.84E-06	Pass	Pass
Eye	3.48E-05		Pass	Pass
Hematopoietic system - HEM	5.88E-04	1.82E-03	Pass	Pass
Immune system - IMM	5.88E-04		Pass	Pass
Kidney - KID		6.91E-06	Pass	Pass
Nervous system - NS	1.39E-05	2.36E-03	Pass	Pass
Reproductive system - REP	6.02E-04		Pass	Pass
Respiratory system - RES	3.48E-05	9.58E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2640 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			9.74E-05		9.74E-05	9.74E-05		9.74E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				2.64E-09					2.64E-09	
Toluene (methyl benzene)			2.31E-06	2.31E-06			2.31E-06	2.31E-06	2.31E-06	
Xylenes (isomers and mixtures)				3.46E-06					3.46E-06	
Total			9.97E-05	5.77E-06	9.74E-05	9.74E-05	2.31E-06	9.97E-05	5.77E-06	

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Attachment D

Compound	HIA - Commercial									
	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			5.88E-04		5.88E-04	5.88E-04		5.88E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				1.60E-08					1.60E-08	
Toluene (methyl benzene)			1.39E-05	1.39E-05			1.39E-05	1.39E-05	1.39E-05	
Xylenes (isomers and mixtures)				2.09E-05					2.09E-05	
Total			6.02E-04	3.48E-05	5.88E-04	5.88E-04	1.39E-05	6.02E-04	3.48E-05	

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Attachment D

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Compound	HIC - Residential												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.72E-04			1.72E-04			1.72E-04			
Chrysene													
Cresol mixtures										6.18E-09			
Ethyl benzene	6.46E-07			6.46E-07	6.46E-07				6.46E-07				
Hexane (n-)										1.90E-05			
Naphthalene												5.85E-05	
Phenol	6.23E-09		6.23E-09						6.23E-09	6.23E-09			
Toluene (methyl benzene)				2.31E-05						2.31E-05		2.31E-05	
Xylenes (isomers and mixtures)										8.85E-06		8.85E-06	
Total	6.52E-07		6.23E-09	1.95E-04	6.46E-07		1.72E-04		6.52E-07	2.23E-04		9.04E-05	

A/N: T2640 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.82E-03			1.82E-03			1.82E-03			
Chrysene													
Cresol mixtures										6.54E-08			
Ethyl benzene	6.84E-06			6.84E-06	6.84E-06				6.84E-06				
Hexane (n-)										2.02E-04			
Naphthalene												6.19E-04	
Phenol	6.60E-08		6.60E-08						6.60E-08	6.60E-08			
Toluene (methyl benzene)				2.45E-04						2.45E-04		2.45E-04	
Xylenes (isomers and mixtures)										9.37E-05		9.37E-05	
Total	6.91E-06		6.60E-08	2.07E-03	6.84E-06		1.82E-03		6.91E-06	2.36E-03		9.58E-04	

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date: 09/10/10

A/N: T2643
Fac: 171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	48	feet
Area (For Volume Source Only)	3000	ft^2
Distance-Residential	700	meters
Distance-Commercial	125	meters
Meteorological Station	Long Beach	

Source Type:	O - Other	
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO	

Emission Units	lb/hr	
[illegible]e output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	2.36E-03	78.11	0.002361449		0.002361449
P15	Chrysene	2.28E-06	228.2928	2.28416E-06		2.28416E-06
C30	Cresol mixtures	1.27E-09	108.14	1.26964E-09		1.26964E-09
E4	Ethyl benzene	2.32E-04	106.16	0.000232303		0.000232303
H8	Hexane (n-)	3.11E-02	86.18	0.031123605		0.031123605
P30	Naphthalene	8.17E-05	128.1732	8.17208E-05		8.17208E-05
P3	Phenol	3.01E-09	94.11	3.00957E-09		3.00957E-09
T3	Toluene (methyl benzene)	1.33E-03	92.13	0.00133255		0.00133255
X1	Xylenes (isomers and mixtures)	9.99E-04	106.2	0.000999018		0.000999018
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N:	T2643
Fac:	171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.282	16.48
Commercial	4.8075	180

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

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Attachment D

Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	2.36E-03	2.36E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	2.28E-06	2.28E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	1.27E-09	1.27E-09		1	1	1	1.0000	600	
Ethyl benzene	2.32E-04	2.32E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	3.11E-02	3.11E-02		1.0000	1.0000	1	1	7000	
Naphthalene	8.17E-05	8.17E-05	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	3.01E-09	3.01E-09		1	1	1	1	200	5800
Toluene (methyl benzene)	1.33E-03	1.33E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	9.99E-04	9.99E-04		1.0000	1.0000	1	1	700	22000

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4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	2.36E-03	2.36E-03	20.6296184	0.010314809
Chrysene	2.28E-06	2.28E-06	0.01995442	9.97721E-06
Cresol mixtures	1.27E-09	1.27E-09	1.1092E-05	5.5458E-09
Ethyl benzene	2.32E-04	2.32E-04	2.02939875	0.001014699
Hexane (n-)	3.11E-02	3.11E-02	271.895811	0.135947905
Naphthalene	8.17E-05	8.17E-05	0.7139126	0.000356956
Phenol	3.01E-09	3.01E-09	2.6292E-05	1.31458E-08
Toluene (methyl benzene)	1.33E-03	1.33E-03	11.6411581	0.005820579
Xylenes (isomers and mixtures)	9.99E-04	9.99E-04	8.72742194	0.004363711
Total	3.61E-02	3.61E-02	3.16E+02	1.58E-01

A/N: T2643 | Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	8.35E-08	2.78E-07
Chrysene	9.37E-10	1.53E-09
Cresol mixtures		
Ethyl benzene	7.15E-10	2.38E-09
Hexane (n-)		
Naphthalene	3.47E-09	1.15E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	8.86E-08	2.93E-07
	PASS	PASS

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	NO
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		2.42E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.13E-10	Pass	Pass
Developmental - DEV	3.33E-04	9.13E-04	Pass	Pass
Endocrine system - END		2.41E-06	Pass	Pass
Eye	1.47E-05		Pass	Pass
Hematopoietic system - HEM	3.27E-04	8.18E-04	Pass	Pass
Immune system - IMM	3.27E-04		Pass	Pass
Kidney - KID		2.42E-06	Pass	Pass
Nervous system - NS	6.48E-06	1.03E-03	Pass	Pass
Reproductive system - REP	3.33E-04		Pass	Pass
Respiratory system - RES	1.47E-05	3.11E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2643 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			2.99E-05		2.99E-05	2.99E-05		2.99E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				8.55E-12					8.55E-12	
Toluene (methyl benzene)			5.94E-07	5.94E-07			5.94E-07	5.94E-07	5.94E-07	
Xylenes (isomers and mixtures)				7.48E-07					7.48E-07	
Total			3.05E-05	1.34E-06	2.99E-05	2.99E-05	5.94E-07	3.05E-05	1.34E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			3.27E-04		3.27E-04	3.27E-04		3.27E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				9.34E-11					9.34E-11	
Toluene (methyl benzene)			6.48E-06	6.48E-06			6.48E-06	6.48E-06	6.48E-06	
Xylenes (isomers and mixtures)				8.17E-06					8.17E-06	
Total			3.33E-04	1.47E-05	3.27E-04	3.27E-04	6.48E-06	3.33E-04	1.47E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				4.80E-05			4.80E-05			4.80E-05			
Chrysene													
Cresol mixtures										2.58E-12			
Ethyl benzene	1.42E-07			1.42E-07	1.42E-07				1.42E-07				
Hexane (n-)										5.42E-06			
Naphthalene												1.11E-05	
Phenol	1.84E-11		1.84E-11						1.84E-11	1.84E-11			
Toluene (methyl benzene)				5.42E-06						5.42E-06		5.42E-06	
Xylenes (isomers and mixtures)										1.74E-06		1.74E-06	
Total	1.42E-07		1.84E-11	5.36E-05	1.42E-07		4.80E-05		1.42E-07	6.06E-05		1.82E-05	

A/N: T2643 | Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				8.18E-04			8.18E-04			8.18E-04			
Chrysene													
Cresol mixtures										4.40E-11			
Ethyl benzene	2.41E-06			2.41E-06	2.41E-06				2.41E-06				
Hexane (n-)										9.24E-05			
Naphthalene												1.89E-04	
Phenol	3.13E-10		3.13E-10						3.13E-10	3.13E-10			
Toluene (methyl benzene)				9.23E-05						9.23E-05		9.23E-05	
Xylenes (isomers and mixtures)										2.97E-05		2.97E-05	
Total	2.42E-06		3.13E-10	9.13E-04	2.41E-06		8.18E-04		2.42E-06	1.03E-03		3.11E-04	

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Attachment D

Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	R510
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	650	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
Source output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	1.07E-03	78.11	0.001071918		0.001071918
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.90E-04	106.16	0.000590183		0.000590183
H8	Hexane (n-)	6.04E-03	86.18	0.006044521		0.006044521
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.49E-03	92.13	0.002487443		0.002487443
X1	Xylenes (isomers and mixtures)	3.71E-03	106.2	0.003706621		0.003706621
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R510
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.302	15.7
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	1.07E-03	1.07E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.90E-04	5.90E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	6.04E-03	6.04E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.49E-03	2.49E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	1.07E-03	1.07E-03	9.36427397	0.004682137
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.90E-04	5.90E-04	5.15583562	0.002577918
Hexane (n-)	6.04E-03	6.04E-03	52.8049315	0.026402466
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.49E-03	2.49E-03	21.7303014	0.010865151
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03	32.3810411	0.016190521
Total	1.43E-02	1.43E-02	1.25E+02	6.23E-02

A/N: R510

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	4.06E-08	3.42E-07
Chrysene	3.51E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	1.94E-09	1.64E-08
Hexane (n-)		
Naphthalene	1.57E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**6.18E-08**	**5.06E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.70E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.91E-04	1.49E-03	Pass	Pass
Endocrine system - END		1.67E-05	Pass	Pass
Eye	5.04E-05		Pass	Pass
Hematopoietic system - HEM	1.76E-04	1.01E-03	Pass	Pass
Immune system - IMM	1.76E-04		Pass	Pass
Kidney - KID		1.70E-05	Pass	Pass
Nervous system - NS	1.44E-05	1.82E-03	Pass	Pass
Reproductive system - REP	1.91E-04		Pass	Pass
Respiratory system - RES	5.04E-05	2.94E-03	Pass	Pass
Skin			Pass	Pass

A/N: R510 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.29E-05		1.29E-05	1.29E-05		1.29E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.09E-09					3.09E-09	
Toluene (methyl benzene)			1.06E-06	1.06E-06			1.06E-06	1.06E-06	1.06E-06	
Xylenes (isomers and mixtures)				2.65E-06					2.65E-06	
Total			1.40E-05	3.70E-06	1.29E-05	1.29E-05	1.06E-06	1.40E-05	3.70E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.76E-04		1.76E-04	1.76E-04		1.76E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.44E-05	1.44E-05			1.44E-05	1.44E-05	1.44E-05	
Xylenes (isomers and mixtures)				3.60E-05					3.60E-05	
Total			1.91E-04	5.04E-05	1.76E-04	1.76E-04	1.44E-05	1.91E-04	5.04E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				2.33E-05			2.33E-05			2.33E-05			
Chrysene													
Cresol mixtures										4.97E-09			
Ethyl benzene	3.85E-07			3.85E-07	3.85E-07				3.85E-07				
Hexane (n-)										1.13E-06			
Naphthalene												5.02E-05	
Phenol	7.45E-09		7.45E-09						7.45E-09	7.45E-09			
Toluene (methyl benzene)				1.08E-05						1.08E-05		1.08E-05	
Xylenes (isomers and mixtures)										6.92E-06		6.92E-06	
Total	3.93E-07		7.45E-09	3.45E-05	3.85E-07		2.33E-05		3.93E-07	4.22E-05		6.79E-05	

6b. Hazard Index Chronic (cont.)

A/N: R510 **Application deemed complete date:** 09/10/10

Compound	HIC - Commercial												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.01E-03			1.01E-03			1.01E-03			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.67E-05			1.67E-05	1.67E-05				1.67E-05				
Hexane (n-)										4.87E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.68E-04						4.68E-04		4.68E-04	
Xylenes (isomers and mixtures)										2.99E-04		2.99E-04	
Total	1.70E-05		3.22E-07	1.49E-03	1.67E-05		1.01E-03		1.70E-05	1.82E-03		2.94E-03	

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Attachment D

Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date: 09/10/10

A/N: R511
Fac: 171107

Stack Data		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	550	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
e output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	1.07E-03	78.11	0.001071918		0.001071918
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.90E-04	106.16	0.000590183		0.000590183
H8	Hexane (n-)	6.04E-03	86.18	0.006044521		0.006044521
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.49E-03	92.13	0.002487443		0.002487443
X1	Xylenes (isomers and mixtures)	3.71E-03	106.2	0.003706621		0.003706621
				0		
				0		
				0		
				0		
				0		
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R511
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.354	18.1
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

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Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	1.07E-03	1.07E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.90E-04	5.90E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	6.04E-03	6.04E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.49E-03	2.49E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	1.07E-03	1.07E-03	9.36427397	0.004682137
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.90E-04	5.90E-04	5.15583562	0.002577918
Hexane (n-)	6.04E-03	6.04E-03	52.8049315	0.026402466
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.49E-03	2.49E-03	21.7303014	0.010865151
Xylenes (isomers and mixtures)	3.71E-03	3.71E-03	32.3810411	0.016190521
Total	1.43E-02	1.43E-02	1.25E+02	6.23E-02

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Attachment D

A/N: R511

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	4.76E-08	3.42E-07
Chrysene	4.12E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	2.28E-09	1.64E-08
Hexane (n-)		
Naphthalene	1.84E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**7.24E-08**	**5.06E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.70E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.91E-04	1.49E-03	Pass	Pass
Endocrine system - END		1.67E-05	Pass	Pass
Eye	5.04E-05		Pass	Pass
Hematopoietic system - HEM	1.76E-04	1.01E-03	Pass	Pass
Immune system - IMM	1.76E-04		Pass	Pass
Kidney - KID		1.70E-05	Pass	Pass
Nervous system - NS	1.44E-05	1.82E-03	Pass	Pass
Reproductive system - REP	1.91E-04		Pass	Pass
Respiratory system - RES	5.04E-05	2.94E-03	Pass	Pass
Skin			Pass	Pass

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Attachment D

A/N: R511 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.49E-05		1.49E-05	1.49E-05		1.49E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.56E-09					3.56E-09	
Toluene (methyl benzene)			1.22E-06	1.22E-06			1.22E-06	1.22E-06	1.22E-06	
Xylenes (isomers and mixtures)				3.05E-06					3.05E-06	
Total			1.61E-05	4.27E-06	1.49E-05	1.49E-05	1.22E-06	1.61E-05	4.27E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.76E-04		1.76E-04	1.76E-04		1.76E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.44E-05	1.44E-05			1.44E-05	1.44E-05	1.44E-05	
Xylenes (isomers and mixtures)				3.60E-05					3.60E-05	
Total			1.91E-04	5.04E-05	1.76E-04	1.76E-04	1.44E-05	1.91E-04	5.04E-05	

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Attachment D

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				2.73E-05			2.73E-05			2.73E-05			
Chrysene													
Cresol mixtures										5.82E-09			
Ethyl benzene	4.52E-07			4.52E-07	4.52E-07				4.52E-07				
Hexane (n-)										1.32E-06			
Naphthalene												5.88E-05	
Phenol	8.74E-09		8.74E-09						8.74E-09	8.74E-09			
Toluene (methyl benzene)				1.27E-05						1.27E-05		1.27E-05	
Xylenes (isomers and mixtures)										8.11E-06		8.11E-06	
Total	4.60E-07		8.74E-09	4.05E-05	4.52E-07		2.73E-05		4.60E-07	4.95E-05		7.96E-05	

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Attachment D

6b. Hazard Index Chronic (cont.)

A/N: R511

Application deemed complete date: 09/10/10

Compound	HIC - Commercial												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.01E-03			1.01E-03			1.01E-03			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.67E-05			1.67E-05	1.67E-05				1.67E-05				
Hexane (n-)										4.87E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.68E-04						4.68E-04		4.68E-04	
Xylenes (isomers and mixtures)										2.99E-04		2.99E-04	
Total	1.70E-05		3.22E-07	1.49E-03	1.67E-05		1.01E-03		1.70E-05	1.82E-03		2.94E-03	

Janice West

From: Matthews, John W (P66) [John.Matthews@p66.com]
Sent: Monday, March 11, 2013 3:01 PM
To: Janice West
Cc: Marshall Waller; Medina, Arquimides J (P66); 'Marcia Baverman'
Subject: RE: AI Request for crude tanks project
Attachments: Existing511.pdf; Existing 510.pdf; Fugitive Components.pdf; [EXTERNAL]RE AI Request for crude tanks project

Proposed Tank 2641 has been removed from this project. The request to cancel application number 544858 was sent on 3/7/13.

Revised Forms 400-E-18 and 400-E-GI will be delivered tomorrow, as we discussed last week.

1. The crude speciation is based on a worst case composite of available assays (see attached e-mail). The highest of each TAC concentration from the assays were used to speciate the liquid composition. Crude characteristics are based on crude with a Reid Vapor Pressure of 11 psia.

2. Based on the revised emission calculations, the proposed TVP limit for tanks 510, 511, 2640, and 2643 is 10.2 psia at [illegible] degrees Fahrenheight. Tank 2641 has been removed from the project, so the emissions remain below the CEQA level of significance as was originally claimed. Monthly throughputs for 510 and 511 remain 1.5 million barrels per month each, and 2640 is 2.5 million barrels per month.

3. The new component lists previously submitted have been reviewed and the corrected lists are attached for Tank 2640 and 2643. Proposed Tank 2641 has been removed from the project. The fugitive counts for 510 and 511 are attached. There are no changes proposed for the 510 and 511 fugitive components.

4. All fugitive components associated with the installation of Tank 2643 are included in the attached table. The crude water draws are compatible with the sour water currently processed in DU-301, and will not affect the design basis of the stripper that was previously reviewed. The total flow will remain below the maximum design flow rate for the stripper of 50,000 GPD. Based on these minor piping changes, no changes to the previously reviewed operating conditions for DU-301 are required, and no permit application has been submitted. In accordance with Permit Condition F25.1 of Section H of the existing Title V permit, any pumps and heat exchangers associated with the installation of the the proposed equipment do not require a permit application.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, January 10, 2013 1:49 PM
To: Matthews, John W (P66)
Subject: [EXTERNAL]AI Request for crude tanks project

Hi John,

As I mentioned on the phone, I am requesting additional information in support of your crude tanks applications. Please provide the following information:

- Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics.

- The true vapor pressure limit you are willing to accept for the operation of these tanks (emissions will be recalculated)
- Fugitive counts for the existing crude tanks (and whether this project will cause any changes—if so, provide pre and post-project counts)
- Information on the impact of the project on the benzene stripper (particularly fugitive counts), and your justification for why an additional application is not needed for that permit unit.

Paul, Tran and I met with Jay yesterday, and after our discussion, Jay instructed me to consider the existing tanks as post-NSR tanks, based on the information in the files, as well as the presence of a throughput limit. I will be re-calculating the baseline emissions using the Tanks program (and the parameters specified in the original permit to operate application), so that the calculation method is the same for pre- and post-project emissions.

Please let me know if you have any comments or questions. I'll wait to proceed until I hear from you.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Phillips 66 Company
Los Angeles Refinery
Fugitive Emission Components

ID 171109, Section D, Process 10, Tank 511

Component	Control	Service	#
Pumps	Sealless	LL	0
	Mechanical seal	LL	1
	Mechanical seal	HL	0
Compressors		Gas/Vap	0
Valves	Bellows sealed	Gas/Vap/LL	16
	Non-bellows sealed	Gas/Vap	0
	Non-bellows sealed	LL	22
PSVs		Gas/Vap/LL	1
Flanges		Gas/Vap/LL	44
Fittings (excluding flanges)		Gas/Vap/LL	30
Other		Gas/Vap/LL	6
Sewer Drains		All	0

Phillips 66 Company
Los Angeles Refinery
Fugitive Emission Components

ID 171109, Section D, Process 10, Tank 510

Component	Control	Service	#
Pumps	Sealless	LL	0
	Mechanical seal	LL	1
	Mechanical seal	HL	0
Compressors		Gas/Vap	0
Valves	Bellows sealed	Gas/Vap/LL	7
	Non-bellows sealed	Gas/Vap	0
	Non-bellows sealed	LL	25
PSVs		Gas/Vap/LL	1
Flanges		Gas/Vap/LL	43
Fittings (excluding flanges)		Gas/Vap/LL	30
Other		Gas/Vap/LL	6
Sewer Drains		All	0

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Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: Philips 66 Carson Plant New Crude Tank 2640

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm): Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	190	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	14	4.55	0	63.64
		Light Liquid (4)	0	0	83	4.55	0	377.30
		Heavy Liquid (5)	0	0		4.55	0	-
		> 6 inches	0	0			0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	5	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	2	46.83	0	
Compressors		Gas / Vapor	0	0		9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	258	6.99	-	1,803.47
Connectors		All	0	0	134	2.86	-	383.43
Pressure Relief Valves		All	0	0	6		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	7	9.09	-	
Total Emissions		lb/year					-	2,628
		lbs/day					0	7.20

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Attachment B
Emissions Calculations

Phillips 66 Carson Plant
Crude Oil Capacity Project

Component Count

Process Unit: Philips 66 Carson Plant New Crude Tank 2643

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm)		
						Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	61	0.00	0	0
	SCAQMD	Gas / Vapor	0	0	0	4.55	0	-
	Approved	Light Liquid (4)	0	0	16	4.55	0	72.73
	I&M Program	Heavy Liquid (5)	0	0	0	4.55	0	-
		> 8 inches	0	0	0		0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	0	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	0	46.83	0	
Compressors		Gas / Vapor	0	0	0	9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	79	6.99	-	552.22
Connectors		All	0	0	20	2.86	-	57.23
Pressure Relief Valves		All	0	0	0		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	1	9.09	-	
Total Emissions		lb/year					-	682
		lbs/day					0	1.87

-1 Any component currently installed prior to the modification.
-2 Any component to be removed due to modification.
-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.
-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF
-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.
-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Janice West

From: Marcia Baverman [mbaverman@envaudit.com]
Sent: Tuesday, February 05, 2013 1:58 PM
To: Matthews, John W (P66)
Cc: mchoi@envaudit.com
Subject: [EXTERNAL]RE: AI Request for crude tanks project
Attachments: TANK Speciation.xlsx

John –

Attached is the derivation of the "hybrid" speciation used to calculate the emissions in the EPA Tanks 4.0 model. The hybrid speciation is the highest concentration for each TAC from each of the three crude speciations used in the most recent AB2588 HRA. The hybrid speciation allows for only having to run one scenario to determine the TAC emissions for use in the HRA.

Thanks -

Marcia Baverman
Project Manager
714-632-8521 ext. 237
mbaverman@envaudit.com

From: Matthews, John W (P66) [mailto:John.Matthews@p66.com]
Sent: Tuesday, January 15, 2013 10:24 AM
To: 'MBaverman@EnvAudit.com'
Subject: FW: AI Request for crude tanks project

As discussed.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, January 10, 2013 1:49 PM
To: Matthews, John W (P66)
Subject: [EXTERNAL]AI Request for crude tanks project

Hi John,

As I mentioned on the phone, I am requesting additional information in support of your crude tanks applications Please provide the following information:

- Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics.
- The true vapor pressure limit you are willing to accept for the operation of these tanks (emissions will be recalculated)
- Fugitive counts for the existing crude tanks (and whether this project will cause any changes—if so, provide pre and post-project counts)
- Information on the impact of the project on the benzene stripper (particularly fugitive counts), and your justification for why an additional application is not needed for that permit unit.

Paul, Tran and I met with Jay yesterday, and after our discussion, Jay instructed me to consider the existing tanks as post-NSR tanks, based on the information in the files, as well as the presence of a throughput limit. I will be re-calculating the baseline emissions using the Tanks program (and the parameters specified in the original permit to operate application), so that the calculation method is the same for pre- and post-project emissions.

Please let me know if you have any comments or questions. I'll wait to proceed until I hear from you.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Phillps 66
Crude Oil Speciation

Chemical	CAS	SJV Crude Wt%	Crude Oils Wt%	Cal Crude Wt%	Crude Hybrid [1] Wt%
Acetaldehyde	75-07-0				0
Ammonia	7664-41-7				0
Anthracene	120-12-7				0
Arsenic	7440-38-2				0
Asbestos (friable)	1332-21-4				0
Benzene	71-43-2	0.03	0.1414124	0.0733333	0.1414124
Benzo(g,h,i)perylene	191-24-2				0
Biphenyl	92-52-4				0
1,3-Butadiene	106-99-0				0
Carbon disulfide	75-15-0				0
Carbonyl sulfide	463-58-1				0
Chromium Compounds	N090				0
Cobalt Compounds	N096	0.0001233		0.00014	0
Copper Compounds	N100	2.333E-05		2.167E-05	0
Cumene	98-82-8		0.002471		0.002471
Cyclohexane	110-82-7	0.1966667	0.62557	0.74	0.74
Diethanolamine	111-42-2				0
Dioxins	N150				0
Ethylbenzene	100-41-4	0.01333	0.1492876	0.0766667	0.1492876
Ethylene	74-85-1				0
Formaldehyde	50-00-0				0
Hydrochloric acid	7647-01-0				0
Hydrogen cyanide	74-90-8				0
Lead Compounds	N420			3.333E-06	0
Manganese Compounds	N450	0.000013		0.0000156	0
Mercury Compounds	N458	1.533E-05		0.000024	0
Methanol	67-56-1				0
Molybdenum trioxide	1313-27-5				0
MTBE	1634-04-4				0
Naphthalene	91-20-3		0.0914786	0.05	0.0914786
n-Hexane	110-54-3	0.2533333		0.8933333	0.8933333
Nickel Compounds	N495	0.0073333		0.0052667	
PACs	N590	0.002	0	0.001	0.002
PAHs (excl naphthalene)	1151	0.002	0	0.001	0.002
Phenanthrene	85-01-8				0
Phenol	108-95-2		0.0002283		0.0002283
Propylene	115-07-1				0
Selenium	7782-49-2				0
Styrene	100-42-5				0
Sulfuric acid	7664-93-9				0
Tetrachloroethylene	127-18-4				0
Toluene	108-88-3	0.0366667	0.5772455	0.27	0.5772455

Trichloroethylene	79-01-6				0
1,2,4-Trimethylbenzene	95-63-6		0.2812269		0.2812269
Vanadium Compounds	N770				0
Xylene (mixed isomers)	1330-20-7	0.026657	0.9441758	0.3633333	0.9441758
Zinc Compounds	N982	0.0001123		9.833E-05	0.0001123
1,1-Dichloro-1-Flouroethane	1717-00-6				0
Acrolein	107-02-8				0
Aluminum	7429-90-5				0
Barium	7440-39-3				0
Benzidine	92-87-5				0
Beryllium	7440-41-7				0
Cadmium Compounds	N078				0
Certain Glycol Ethers	N230				0
Chlorine	7782-50-5				0
Cresol (mixed isomers)	1319-77-3		0.0005707		0.0005707
Cumene hydroperoxide	80-15-9				0
Di(2-ethylhexyl) phthalate	117-81-7				0
Dichlorobenzene (mixed)	25321-22-6				0
Ethylene glycol	107-21-1				0
HCFC-22	75-45-6				0
Hydroquinone	123-31-9				0
Methyl ethyl ketone	78-93-3				0
Methyl isobutyl ketone	108-10-1				0
n-Butyl alcohol	71-36-3				0
Nitrate Compounds	N511				0
Silver Compounds	N740				0
Sodium nitrite	7632-00-0				0
					0
					0
					0
Polycyclic Aromatic Compounds (Speciated)					
1-Nitropyrene	5522-43-0				0
3-Methylcholanthrene	56-49-5				0
5-Methylchrysene	3697-24-3				0
7,12-Dimethylbenzen(a)-anthracene	57-97-6				0
7H-Dibenzo(c,g)carbazole	194-59-2				0
Benzo(a)anthracene	56-55-3				0
Benzo(a)phenanthrene	218-01-9	0.002		0.001	0.002
Benzo(a)pyrene	50-32-8				0
Benzo(b)fluoranthene	205-99-2				0
Benzo(j)fluoranthene	205-82-3				0
Benzo(j,k)fluorene	206-44-0				0
Benzo(k)fluoranthene	207-08-9				0
Benzo(r,s,t)pentaphene	189-55-9				0
Dibenz(a,h)acridine	226-36-8				0
Dibenz(a,j)acridine	224-42-0				0
Dibenzo(a,e)fluoranthene	5385-75-1				0
Dibenzo(a,e)pyrene	192-65-4				0
Dibenzo(a,h)anthracene	53-70-3				0
Dibenzo(a,h)pyrene	189-64-0				0
Dibenzo(a,l)pyrene	191-30-0				0

Indeno(1,2,3-cd)pyrene	193-39-5				0
PACs	N590	0.002	0	0.001	0.002
					0
Polynuclear Aromatic Hydrocarbons (Speciated)					
Benzo(a)pyrene	50-32-8	0	0	0	0
Dibenz(a,h)anthracene	53-70-3	0	0	0	0
Benz(a)anthracene	56-55-3	0	0	0	0
Acenaphthene	83-32-9				0
Phenanthrene	85-01-8	0	0	0	0
Fluorene	86-73-7				0
Naphthalene	91-20-3		0.0914786	0.05	0.0914786
2-Methyl naphthalene	91-57-6				0
Anthracene	120-12-7	0	0	0	0
Pyrene	129-00-0				0
Dibenzo(a,i)pyrene	189-55-9	0	0	0	0
Dibenzo(a,h)pyrene	189-64-0	0	0	0	0
Benzo(g,h,i)perylene	191-24-2	0	0	0	0
Dibenzo(a,l)pyrene	191-30-0	0	0	0	0
Dibenzo(a,e)pyrene	192-65-4	0	0	0	0
Benzo(e)pyrene	192-97-2				0
Indeno(1,2,3-cd)pyrene	193-39-5	0	0	0	0
Perylene	198-55-0				0
Benzo(j)fluoranthene	205-82-3	0	0	0	0
Benzo(b)fluoranthene	205-99-2	0	0	0	0
Fluoranthene	206-44-0	0	0	0	0
Benzo(k)fluoranthene	207-08-9	0	0	0	0
Acenaphthylene	208-96-8				0
Chrysene	218-01-9	0.002	0	0.001	0.002
PAHs (excl Naphthalene)	1151	0.002	0	0.001	0.002

(1) Crude Hybrid is maximum wt% of volatile components. Non-volatile components excluded (metals).

ENGINEERING & COMPLIANCE . . . MEMORANDUM

TO: File	FROM: Janice West	DATE: 1/9/13
REFERENCE: Phillips 66 crude tank project		PERMIT APPL. NO.: 544857-544861
SUBJECT: NSR status of existing crude tanks Tk 510 (D394) and Tk 511 (D395)		

A meeting was held 1/9/13 in Room 3C to discuss recent applications from Phillips 66. Attending: Jay Chen, Tran Vo, Paul Park, and Janice West

After providing background on the proposed project, I reviewed the history of the tank permit units, noting that the original construction PC was issued 4/5/74 (this PC expired and was re-issued 5/14/76). Both of these dates are before the original New Source Review Rules (Rule 213) were adopted by the California Air Resources Board on October 8, 1976.

The first Permit to Operate was not issued until A/N C18850 {M12252}, a modification to upgrade tank 510 (D394) seals for Rule 463 compliance, was issued a Permit to Operate 11/13/80 (then reissued twice on 12/29/82 and again on 1/10/84). Note that Tanks 510 and 511 have parallel histories, and started out as identical tanks, and were modified at the same time in most instances—the Tank 510 history was used for discussion purposes). As part of the engineering evaluation for A/N C18850, it is stated that "an emission reduction will develop and B.A.C.T. will be utilized so Rule 213 will be satisfied." In the same evaluation, written by Dave Schwein, the emission data sheet shows check marks in boxes indicating "rule reduction", "Rule 213 applicable (unit installed or permit to construct issued on or subsequent to 10/8/76)", and "BACT evaluation: Not Made". These seemingly contradictory statements made the NSR status (pre-NSR or post-NSR) of these tanks unclear.

The reason for at least one of the reissuances of A/N C18850 was due to a decision by the Hearing Board, resulting in removal of all permit conditions (a vapor pressure limit and a seal installation requirement). No records of this Hearing Board decision have been located, so the content of the permit appeal are unknown.

All subsequent applications for these permit units involved seal upgrades, administrative changes, or changes of ownership. None of these applications had emission increases that triggered the current requirements for NSR at the time they were issued permits.

In 2002, as part of cleanup prior to issuing the Title V permit, throughput limits were added to the facility permit for tanks D394 and D395. Typically, throughput limits are applied only to post-NSR tanks. There are no records of the facility objecting to these throughput limits, which were based on the throughputs proposed as part of the original new construction of the tanks.

The facility submitted applications for modification to these two existing tanks, and contemporaneous construction of three new tanks, resulting in total emissions from the three new and two existing tanks of 70.78 lb/day. The facility also stated that the post-NSR tanks' potential to emit was 207.4 lb/day (total for both tanks), showing a net emissions reduction for the project.
After some discussion, Jay stated that he felt the tanks should continue to be treated as post-NSR tanks, as mentioned in the evaluation for A/N C18850, and as indicated by the current throughput limits. Tran mentioned that standard practice may have been different at that time, and internal procedures may have called for setting an NSR emissions baseline when modifications were performed. Paul did not agree, and stated that NSR should not have been triggered because the seal upgrade caused an emission reduction, so no NSR review should have been necessary, and they should be considered pre-NSR tanks despite the presumed errors in the evaluation. Jay's final decision was to treat the tanks as post-NSR tanks for emission calculation purposes.
Jay further stated that he had no objections to use of contemporaneous reduction to account for the emissions from new construction of the three new tanks. Tran recommended updating the tank emission calculation using the current version of Tanks 4.0 (but with the same tank parameters), but Jay did not expect that to have a significant impact on the number of offsets required for the project.

Table 3 Emission Reduction Credits Summary (from facility submittal)

Tank No.		Emissions (lbs/day)
Post Project Emissions		
	Existing Tank 510 Crude Tank	12.5
	Existing Tank 511 Crude Tank	12.5
	New Tank 2640 Crude Tank	15.89
	New Tank 2641 Crude Tank	15.89
	New Tank 2643 Water Draw Tank	2.54
	Fugitive Emissions	11.46
Total Project Emissions		70.78
NSR Balance for Tanks 510 and 511		207.4
Offsets required		0

Permitting History for Tank 510 (D394)

A/N	Permit #	Facility ID	description	received	Permit issued	Emissions	Conditions
Tank 510 (D394)							
535286	G17717	171109	Change of operator from ConocoPhillips to Phillips 66	3/27/12	6/12/12		(same)
487992	F99603	800362	Administrative change to add "two tank mixers" to device description	8/28/08	11/7/08		(same)
407453	F62413	800362	Administrative change - upgrade primary & secondary seals	10/8/02	8/5/03	no NSR eval	(same)
					7/10/02		C1.17 (throughput <4.5625e6 bbl/yr), H23.4 (NSPS K, R1149 appl)
					1/1/02		1-17 (throughput <4.5625e6 bbl/yr), 22-4 (tvp <11psia), 23-4 (NSPS K, 1149 appl)
325644	F6643	800362	Change of ownership from Unocal to Tosco	3/12/97	6/10/97		(none)
257958	D45670	88892 - Unocal Corp, Union Oil Co of Cal Unit 38	Change of ownership from Shell to Unocal	11/15/91	12/9/91	data taken from previous permit: ROG R1: 212 lb/hr, R2: 111 lb/hr	Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the applciation under which this permit is issued unless otherwise noted below. This equipment shall be properly maintained and kept in good operating condition at all times.

C18850	R-M12252	8458	permit revised to add two mixers Fiche 09521 C14	-	1/10/84		
C18850	R-M12252	8458	Permit revised	-	12/29/82 10/16/78 PC		
C18850	M12252	8458 - Shell Oil Co Unit No. 15	Modification to install secondary seals for R463 complianceavg throughput: 12,500 bbl/d (4,562,500 bbl/yr)Eval states: "An emission reduction will develop and BACT will be utilized to Rule 213 will be satisfied."	-	11/13/80 10/16/78 PC	R1: 212, R2: 111calcs show present: 398.4 lb/d, proposed: 103.7 lb/d (294.7 lb/d reduction in losses)	This tank must not be used for storing organic liquid having a vapor pressure of 569 mm Hg (11 psia) or greater under actual storage conditions.Installation of the approved secondary seal is not to begin until the primary seal has been inspected and approved by the SCAQMD.
Note on 12/27/82 instruction sheet for permit wording and fee data: Delete existing conditions on P/O and reissue P/O. Comments: Special Instr. - As per decision of Hearing Board on Shell delete all conditions on M-12252 and reissue P/O prev conditions: 1. This tank must not be sued for storing organic liquid having a vapor pressure of 559 mm Hg (11 psia) or greater under actual storage conditions. 2. The roof must be kept floating at all times, except when supported on the legs for the purpose of emptying the tank. When the roof is on its legs, the tank must be emptied of organic materials as rapidly as possible. To prevent excessive filling losses, water should be used for refloating the roof.							
C08256		shell	change of operator				
C03789		arco	Resubmittal of PC application because construction was delayed by EIR(description changed to remove "pontoon" from floating roof and add "tube" to seal		5/14/76 PC	emission reduction, exempt. Losses: 212 lb/day (due to different wind speed and avg temp and vapor pressure in calcs)	This tank must not be used for storing petroleum distillate having a vapor pressure of 11 psia or greater under actual storage conditions. This tank must not be operated after July 1, 1977 unless it meets the floating roof closure and roof opening criteria of Rule 463 as amended May 7, 1976,
A79818			New construction of tanks 510-513, 951-953 avg throughput: 12,500 bbl/d (4,562,500 bbl/yr)	~3/12/74	4/5/74 PC	losses: 409 lb/day, 74.6 tons/yr (reduction of 12,240 lb/day relative to fixed roof tank)	This tank must not be used for storing petroleum distillate having a vapor pressure of 11 psia or greater under actual storage conditions.

Janice West

From: Matthews, John W (P66) [John.Matthews@p66.com]
Sent: Tuesday, January 08, 2013 2:16 PM
To: Janice West
Subject: RE: Tanks 510 & 511 & NSR
Attachments: Calcsheet.pdf

Dave Schwien's intent regarding Rule 213 seems to be clearly stated on the second page of the attached calculations from the Tank R-510 permit file (Application # C18850).

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Wednesday, December 19, 2012 6:40 PM
To: Matthews, John W (P66)
Subject: [EXTERNAL]Tanks 510 & 511 & NSR

Hi John,

I recognize that there has possibly been some confusion regarding the NSR status of these tanks. Paul pointed out that the version of Rule 213 that was valid at that time (1978) placed requirements *(BACT and verification that violations of the NAAQS would not be caused)* only on modifications to sources that emit more than 15 lbs/hr or more than 150 lbs/day of organic gases (see excerpt below and attached (outdated) rule). The modification to install a secondary seal was an emission reduction noted as a "rule reduction" (for Rule 463 compliance) in the A/N C-18850 data sheet, and the unit did not emit more than 15 lbs/hr.

It is likely that the notation of Rule 213 applicability was made in error, and was the cause of the Hearing Board action that later removed the vapor pressure limit from the permit. I haven't been able to locate any Hearing Board files, however. Any documentation you can find on the Hearing Board Case (Shell Oil facility ID 8458, sometime between 11/13/80 when the PO was issued and 12/29/82, when the permit was re-issued) may be helpful.

We are planning to have an internal meeting to discuss this situation, but Jay is out of the office until next year. I will also be out of the office until next year starting tomorrow. Hopefully, we will be able to resolve this concern early in January.

Please let me know if you find any additional information that would shed light on the situation.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

"(b)Best Available Control Technology
(b)(2) Modifications to Existing Stationary Sources:
The Air Pollution Control Officer shall deny a permit to construct for any modification of any existing stationary source if such source after modification will emit more than 15 pounds per hour or more than 150 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a state or national ambient air quality standard (except carbon monoxide, for which the limits are 150 pounds per hour and 1500 pounds per day), unless the applicant demonstrates that the modification of the existing stationary source will be constructed using best available technology, and..."

. . .
"(c) Air Quality Impact Analysis:
(c)(2) Modifications to Existing Stationary Sources:

The Air Pollution Control Officer shall deny -a permit to construct for any modification of any existing stationary source if the modification will result in a net increase in emissions from the existing source of more than 250 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a national ambient air quality standard (except carbon monoxide, for which the limits are 2500 pounds per day), or which is a precursor of any such air contaminant, unless he determines that the emissions from the modified source will not cause a violation of the national ambient air quality standard for that same contaminant, (or in the case of a precursor, for that contaminant to which the precursor contributes)."
–SCAQMD Rule 213 (Adopted 10/8/76) — note that this rule was amended 4/6/79 and rescinded 6/28/90)

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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ENGINEERING DIVISION
APPLICATION PROCESSING AND CALCULATIONS
P/C

COMPANY: SHELL OIL COMPANY
1622 EAST SEPULVEDA BLVD., CARSON CA 90749

EQUIPMENT DESCRIPTION:

APPLICATION C-18847:

ALTERATION OF TANK NO. R-513 AS DESCRIBED BY PREVIOUS APPL'N ~~PERMIT~~ C-08257 BY THE ADDITION OF A SECONDARY SEAL.

APPLICATION C-18848:

ALTERATION OF TANK NO. R-512 AS DESCRIBED BY PREVIOUS APPL'N ~~PERMIT~~ C-08254 BY THE ADDITION OF A SECONDARY SEAL.

APPLICATION C-18849:

ALTERATION OF TANK NO. R-511 AS DESCRIBED BY PREVIOUS APPL'N ~~PERMIT~~ C-08255 BY THE ADDITION OF A SECONDARY SEAL.

APPLICATION C-18850:

ALTERATION OF TANK NO. R-510 AS DESCRIBED BY PREVIOUS APPL'N ~~PERMIT~~ C-08256 BY THE ADDITION OF A SECONDARY SEAL.

BACKGROUND:

THE TANKS LISTED ABOVE ARE OWNED BY ARCO AND LEASED FOR OPERATION FROM ARCO BY SHELL. BOTH COMPANIES HAD SUBMITTED APPLICATIONS FOR THEIR OPERATION:

OLD TANK NO.	OLD ARCO APPL'N NO.	OLD SHELL APPL'N NO	NEW TANK NO.	SHELL TYPE ROOF TYPE	TYPE PRIMARY SEAL	CONTENTS
510	C-03789	C-08256	R-510	WELDED PONTOON	TUBE	CRUDE
511	C-03790	C-08255	R-511	"	"	"
512	C-03791	C-08254	R-512	"	"	"
513	C-03792	C-08257	R-513	"	"	"

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

ENGINEERING DIVISION
APPLICATION PROCESSING AND CALCULATIONS

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PROCESSED BY DLS	CHECKED BY

CALCULATIONS:

SEE ATTACHED CALCULATION SHEET. AN EMISSION REDUCTION WILL DEVELOP AND B.A.C.T. WILL BE UTILIZED SO RULE 213 WILL BE SATISFIED. THE SPECIFIC SECONDARY SEAL TO BE USED IS CALLED THE "WEATHERGUARD SEAL" AND WILL BE PROVIDED BY REPUBLIC FABRICATORS. THIS IS AN SCAQMD APPROVED SEAL.

RECOMMENDATIONS:

ISSUE CONDITIONAL P/C'S.

Janice West

From: Janice West
Sent: Wednesday, December 19, 2012 2:51 PM
To: 'john.matthews@p66.com'
Subject: Tanks 510 and 511

Hi John,

I recently began my review of the Tank applications you submitted in November. Based on my more extensive review of the permitting history of Tanks 510 and 511, it appears that some adjustments are needed to your emission calculations.

The New Source Review Rule (originally Rule 213) was first adopted by the AQMD on October 8, 1976. The original permits to construct for the new construction of four crude tanks (Tanks 510, 511, 512, and 513) were issued April 5, 1974, then reissued (after a construction delay caused by waiting for an EIR) on 5/14/76. None of the modifications made since appear to have involved an emission increase (most were administrative revisions, change of ownership or tank seal upgrades). Therefore it appears that these tanks were never subject to Rule 213 or Regulation XIII, and thus the determination of required offsets and BACT applicability shall be based on the post-modification potential to emit minus the actual emissions (from the previous two-year period) per Rule 1306(d)(2)(B) and not the pre-modification potential to emit.

The District has always calculated emissions associated with permit units, but it appears that the calculations performed for these tanks were not part of any NSR event and have not included any offsets.

I looked into the AER reports for the last 10+ years, and it appears that you have typically reported less than 5 lb/day for each tank. The throughputs were close to the annual limit (some even appear to have exceeded the limit), but the primary difference appears to be the use of 2.33 for the vapor pressure in your emission calculations. If this is incorrect, you may wish to amend your AER reports. I will also need your 2012 actual emissions for calculating the actual emissions during the two-year period immediately preceding the date of permit application (11/27/12) [see 1306(c)(1) via 1306(d)(2)(B)]. Since you have proposed that the post-modification PTE will be 12.5 (each), this may ultimately represent a nearly 8 lb/day increase per existing tank, and does not mitigate increases from the new tanks.

Please let me know your comments,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Tank 510

Form B6	Total Loss (lbs/yr)	Loss (lb/day)	True Vapor Pressure	Throughput (1000 gal)	Throughput (bbl)
AER 2011	1643	4.56	2.33	192820	**4,590,943**
AER 2010	1515	4.21	2.33	165961	3,951,459
AER 2009	not available				
AER 2008	1540	4.28	2.33	171111	4,074,078
AER 06-07	1643	4.56	2.33	192930	**4,593,565**
AER 05-06	1715	4.76	2.33	207974	**4,951,768**
AER 04-05	1415	3.93	2.33	144840	3,448,566

AER 03-04	1510	4.19	2.33	222212	5,290,760
AER 02-03	507	1.41	2.33	77227	1,838,727
AER 01-02	1423	3.95	3.62	167799	3,995,221
AER 00-01	1400	3.89	1.70	134500	3,202,387
				annual throughput limit (bbl):	*4,562,000*

Tank 511

Form B6	Total Loss (lbs/yr)	Loss (lb/day)	True Vapor Pressure	Throughput (1000 gal)	Throughput (bbl)
AER 2011	1660	4.61	2.33	196266	4,672,991
AER 2010	1618	4.49	2.33	187361	4,460,979
AER 2009	not available				
AER 2008	1375	3.82	2.33	136236	3,243,713
AER 06-07	1600	4.44	2.33	183545	4,370,125
AER 05-06	1558	4.33	2.33	174687	4,159,211
AER 04-05	1484	4.12	2.33	159156	3,789,420
AER 03-04	1453	4.04	2.33	205836	4,900,852
AER 02-03	1509	4.19	2.33	170313	4,055,061
AER 01-02	2087	5.80	3.62	192693	4,587,929
AER 00-01	7346	20.41	4.00	134331	3,198,347
				annual throughput limit (bbl):	*4,562,000*

HISTORY of Tank 510 (note that Tank 511 is similar)

A/N	Permit #	Facility ID	description	received	Permit issued	Conditions
TANK 510 (D394)						
535286	G17717	171109	Change of operator from ConocoPhillips to Phillips 66	3/27/12	6/12/12	(same)
487992	F99603	800362	Administrative change to add "two tank mixers" to device description	8/28/08	11/7/08	(same)
407453	F62413	800362	Administrative change - upgrade primary & secondary seals	10/8/02	8/5/03	(same)
					7/10/02	C1.17 (throughput <4.5625e6 bbl/yr), H23.4 (NSPS K, R1149 appl)
					1/1/02	1-17 (throughput <4.5625e6 bbl/yr), 22-4 (tvp <11psia), 23-4 (NSPS K, 1149 appl)
325644	F6643	800362	Change of ownership from Unocal to Tosco	3/12/97	6/10/97	(none)
257958	D45670	88892 - Unocal Corp, Union Oil Co of Cal Unit 38	Change of ownership from Shell to Unocal	11/15/91	12/9/91	Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below. This equipment shall be properly maintained and kept in good operating condition at

						all times.
C18850	R-M12252	8458	permit revised to add two mixers	-	1/10/84	(none)
C18850	R-M12252	8458	Permit revised to remove conditions per Hearing Board	-	12/29/82	(none)
C18850	M12252	8458 - Shell Oil Co Unit No. 15	Modification to install secondary seals for R463 compliance		11/13/80 10/16/78 PC	This tank must not be used for storing organic liquid having a vapor pressure of 569 mm Hg (11 psia) or greater under actual storage conditions. Installation of the approved secondary seal is not to begin until the primary seal has been inspected and approved by the SCAQMD.
C08256		Shell	change of operator (Shell as lessee operator of tanks)	10/14/76		
C03789		Arco	Resubmittal of PC application because construction was delayed by EIR and City of Carson special use permit.	3/15/76	5/14/76 PC	This tank must not be used for storing petroleum distillate having a vapor pressure of 11 psia or greater under actual storage conditions. This tank must not be operated after July 1, 1977 unless it meets the floating roof closure and roof opening criteria of Rule 463 as amended May 7, 1976,
A79818		Atlantic Richfield Company	New construction of tanks 510-513, 951-953 avg throughput: 12,500 bbl/d (4,562,500 bbl/yr) Replacing 785,000 bbl fixed roof storage reservoir. Four tanks (510-513) leased to Shell.	3/12/74	4/5/74 PC (expired 4/5/76)	This tank must not be used for storing petroleum distillate having a vapor pressure of 11 psia or greater under actual storage conditions.

South Coast Air Quality Management District

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FACILITY : 800362 Year 2008 +

- Not Started
- Started

0

B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☑ The Data is Imported from the EPA Tank4 Application

Tank Description:	36.Tank 510 Basrah/ANS/Oriente cru *
Product Code (See Supplemental Inst. Book):	999. Other *
Product Description :	LARC Mixed crude oils *
Tank ID Number:	D394 *
Max. Storage Capacity, C, (1000 gallons):	13440 *
Tank Diameter, D, (ft):	218 *
Annual Throughput, Q, (1000 gallons):	171111.29 *
Vapor Molecular Weight, Mv, (lb/lb mole):	50
Liquid Density, WL:	7.686
Material True Vapor Pressure, PVA:	2.334505
Pressure Function, FP:	0.0431978
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015
TAC/ODC:	☐
Permit Device IDs:	D394 *

Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Roof Support Factor, Nc:	0 *
Rim Seal Loss Factor, KR:	3.1433333 *
Roof Fitting Loss Factor, FF:	156.11731 *
Deck Seam Loss Factor, KD:	0 *
Deck Seam Length Factor, SD:	0 *
Calculated Working Loss, LW , (lbs/yr):	812.71114
Calculated Rim Seal Loss, LR, (lbs/yr):	592.02390
Calculated Deck Fitting Loss, LF, (lbs/yr):	134.87870
Calculated Deck Seam Loss, LD, (lbs/yr):	0
Total Excess Emission From Upsets, LX, (lbs/yr):	0 *
Calculated Total Loss, LT (lbs/yr)(LW+LR+LF+LD+LX)	1539.6137

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– Started

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B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☒ The Data is Imported from the EPA Tank4 Application

Tank Description:	37.Tank 511 Maya/Eocene crude *
Product Code (See Supplemental Inst. Book):	999. Other *
Product Description	LARC Mixed crude oils *
Tank ID Number:	D395 *
Max. Storage Capacity, C, (1000 gallons):	13440 *
Tank Diameter, D, (ft):	218 *
Annual Throughput, Q, (1000 gallons):	136235.95 *
Vapor Molecular Weight, Mv, (lb/lb mole):	50
Liquid Density, WL:	7.686
Material True Vapor Pressure, PVA:	2.334505
Pressure Function, FP:	0.0431978
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015
TAC/ODC:	☐
Permit Device IDs:	D395 *

Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Roof Support Factor, Nc:	0 *
Rim Seal Loss Factor, KR:	3.1433333 *
Roof Fitting Loss Factor, FF:	157.49171 *
Deck Seam Loss Factor, KD:	0 *
Deck Seam Length Factor, SD:	0 *
Calculated Working Loss, LW, (lbs/yr):	647.06705
Calculated Rim Seal Loss, LR, (lbs/yr):	592.02390
Calculated Deck Fitting Loss, LF, (lbs/yr):	136.06612
Calculated Deck Seam Loss, LD, (lbs/yr):	0
Total Excess Emission From Upsets, Lx, (lbs/yr):	0 *
Calculated Total Loss, LT (lbs/yr)(LW+LR+LF+LD+LX)	1375.1570

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  - WT
  - X

- Not Started
- Started

0

B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☑ The Data is Imported from the EPA Tank4 Application

Field	Value
Tank Description:	41.Tank 510 Basrah/ANS/Oriente cru *
Product Code (See Supplemental Inst. Book):	999. Other *
Product Description :	LARC MIXED CRUDE OILS *
Tank ID Number:	D394 *
Max. Storage Capacity, C, (1000 gallons):	13440 *
Tank Diameter, D, (ft):	218 *
Annual Throughput, Q, (1000 gallons):	165961.29 *
Vapor Molecular Weight, Mv, (lb/lb mole):	50
Liquid Density, WL:	7.686
Material True Vapor Pressure, PVA:	2.334505
Pressure Function, FP:	0.0431978
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015
TAC/ODC:	☐
Permit Device IDs:	D394 *

Field	Value
Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Roof Support Factor, Nc:	0 *
Rim Seal Loss Factor, KR:	3.1433333 *
Roof Fitting Loss Factor, FF:	156.11731 *
Deck Seam Loss Factor, KD:	0 *
Deck Seam Length Factor, SD:	0 *
Calculated Working Loss, Lw , (lbs/yr):	788.25069
Calculated Rim Seal Loss, LR, (lbs/yr):	592.02390
Calculated Deck Fitting Loss, LF, (lbs/yr):	134.87870
Calculated Deck Seam Loss, LD, (lbs/yr):	0
Total Excess Emission From Upsets, Lx, (lbs/yr):	0 *
Calculated Total Loss, LT (lbs/yr)(Lw+LR+LF+LD+Lx)	1515.1532

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B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☑ The Data is Imported from the EPA Tank4 Application

Tank Description:	42.Tank 511 Maya/Eocene crude *
Product Code (See Supplemental Inst. Book):	999. Other *
Product Description :	LARC MIXED CRUDE OILS *
Tank ID Number:	D395 *
Max. Storage Capacity, C, (1000 gallons):	13440 *
Tank Diameter, D, (ft):	218 *
Annual Throughput, Q, (1000 gallons):	187361.11 *
Vapor Molecular Weight, Mv, (lb/lb mole):	50
Liquid Density, WL:	7.686
Material True Vapor Pressure, PVA:	2.334505
Pressure Function, FP:	0.0431978
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015
TAC/ODC:	☐
Permit Device IDs:	D395 *

Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Roof Support Factor, Nc:	0 *
Rim Seal Loss Factor, KR:	3.1433333 *
Roof Fitting Loss Factor, FF:	157.49171 *
Deck Seam Loss Factor, KD:	0 *
Deck Seam Length Factor, SD:	0 *
Calculated Working Loss, Lw , (lbs/yr):	889.89135
Calculated Rim Seal Loss, LR, (lbs/yr):	592.02390
Calculated Deck Fitting Loss, LF, (lbs/yr):	136.06612
Calculated Deck Seam Loss, LD, (lbs/yr):	0
Total Excess Emission From Upsets, Lx, (lbs/yr):	0 *
Calculated Total Loss, LT (lbs/yr)(Lw+LR+LF+LD+Lx)	1617.9813

* Required Fields

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■ - Not Started

■ - Started

0

B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☑ The Data is Imported from the EPA Tank4 Application

Field	Value	Field	Value
Tank Description:	14.Tank 510 *	Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Product Code (See Supplemental Inst. Book):	999. Other *	Roof Support Factor, Nc:	0 *
Product Description :	LARC MIXED CRUDE OILS *	Rim Seal Loss Factor, KR:	3.1433333 *
Tank ID Number:	D394 *	Roof Fitting Loss Factor, FF:	156.11731 *
Max. Storage Capacity, C, (1000 gallons):	13440 *	Deck Seam Loss Factor, KD:	0 *
Tank Diameter, D, (ft):	218 *	Deck Seam Length Factor, SD:	0 *
Annual Throughput, Q, (1000 gallons):	192819.60 *	Calculated Working Loss, LW , (lbs/yr):	915.81704
Vapor Molecular Weight, MV, (lb/lb mole):	50	Calculated Rim Seal Loss, LR, (lbs/yr):	592.02390
Liquid Density, WL:	7.686	Calculated Deck Fitting Loss, LF, (lbs/yr):	134.87870
Material True Vapor Pressure, PVA:	2.334505	Calculated Deck Seam Loss, LD, (lbs/yr):	0
Pressure Function, FP:	0.0431978	Total Excess Emission From Upsets, LX, (lbs/yr):	0 *
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015	Calculated Total Loss, LT (lbs/yr)(LW+LR+LF+LD+LX)	1642.7196
TAC/ODC:	☐		
Permit Device IDs:	D394 *		

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  - X

– Not Started

– Started

0

B6 - Permitted Internal/External Floating Roof Tank Calculation Sheet

IMPORT TANK

☒ The Data is Imported from the EPA Tank4 Application

Field	Value
Tank Description:	15.Tank 511 *
Product Code (See Supplemental Inst. Book):	999. Other *
Product Description :	LARC MIXED CRUDE OILS *
Tank ID Number:	D395 *
Max. Storage Capacity, C, (1000 gallons):	13440 *
Tank Diameter, D, (ft):	218 *
Annual Throughput, Q, (1000 gallons):	196265.61 *
Vapor Molecular Weight, M_V, (lb/lb mole):	50
Liquid Density, W_L:	7.686
Material True Vapor Pressure, P_{VA}:	2.334505
Pressure Function, F_P:	0.0431978
Shell Clinage Factor, Sc (0.006 for crude oil:0.0015 for others):	0.0015
TAC/ODC:	☐
Permit Device IDs:	D395 *

Field	Value
Product Factor Kc (0.4 for crude oil: 1.0 for other):	1.0
Roof Support Factor, N_C:	0 *
Rim Seal Loss Factor, K_R:	3.1433333 *
Roof Fitting Loss Factor, F_F:	157.49171 *
Deck Seam Loss Factor, K_D:	0 *
Deck Seam Length Factor, S_D:	0 *
Calculated Working Loss, L_W , (lbs/yr):	932.18425
Calculated Rim Seal Loss, L_R, (lbs/yr):	592.02390
Calculated Deck Fitting Loss, L_F, (lbs/yr):	136.06612
Calculated Deck Seam Loss, L_D, (lbs/yr):	0
Total Excess Emission From Upsets, L_X, (lbs/yr):	0 *
Calculated Total Loss, L_T (lbs/yr)($L_W+L_R+L_F+L_D+L_X$)	1660.2742

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AQMD Form 400-E-GI

Philips 66 – Los Angeles Refinery Carson Plant
Facility ID No. 171109

Permit Application

Supplemental Information Package
Crude Capacity Project Tanks

<u>**Sections**</u>

<u>**Attachments**</u>

November 15, 2012

1. COMPANY INFORMATION

Mailing Address
1660 W. Anaheim St.
Wilmington, CA 90744

Site Location
Carson Plant
1520 E. Sepulveda Blvd.
Carson, CA 90745

2. BACKGROUND

The Philips 66 Los Angeles Refinery Carson Plant (LARC) operates a crude supply storage tanks to handle incoming crude supplies from domestic as well as various sources from the Port of Long Beach, Berth 121.

LARC currently has four 320,000 barrel (BBL) receiving tanks (285,000 BBL net working capacity) for crude. These tanks usually store three segregated crude grades at a time, which essentially limits deliveries volumes to Panamax vessels (400,000 BBL capacity). For larger vessels, such as Aframax (720,000 BBL) or Suezmax (1,000,000 BBL), LARC requires two ship calls to unload the full volume of the vessels, resulting in seven to 10 days of demurrage between ship calls. Between ship calls LARC makes room in the receiving tanks to accommodate the second discharge from the larger vessel. LARC needs more tankage and capacity to accommodate the larger vessels so they can discharge their total volume in one call.

3. PROJECT DESCRIPTION

The project will increase the onsite crude storage capacity by installing two new 575,000 BBL (500,000 BBL net working capacity) domed external floating roof crude tanks (Tank 2640 and 2641) and geodesic domes on two of the existing crude tanks (Tank R510 (Device D394) and Tank R511(Device D395)). The project also includes the construction of a new 11,500 BBL (10,000 BBL net working capacity) domed external floating roof water draw tank (Tank 2643).

Currently, the water draw from the existing crude tanks is processed in the sour water stripper which is at times overloaded. The water draw from the existing R510 and R511 tanks and new Tanks 2640 and 2641 will be routed to the new water draw Tank 2643. The new 11,500 BBL water draw tank will allow LARC to treat the water at the Brine Stripper, which has excess capacity. Minor modifications are required to the Brine Stripper, consisting of the installation of new heat exchangers and a steam trim heater to raise the temperature of the water before entering the Brine Stripper.

4. EQUIPMENT LOCATION AND TANK DESCRIPTION

The new tanks and tank modifications will be located at the western boundary of LARC. Table 1 shows the specifications of the existing and proposed tanks. Please refer to the Figures 1, 2, and 3 in Attachments A for locations.

TABLE 1
Tank Specifications

Tank Number	Roof Type	Commodity Type	Working Volume (BBL)	Diameter (ft)	Height (ft)	Dome Roof (ft)
Existing 510	Pontoon	Crude Oil	285,000	218	50	42
Existing 511	Pontoon	Crude Oil	285,000	218	50	42
Modified 510	Domed	Crude Oil RVP 7	285,000	218	50	42
Modified 511	Domed	Crude Oil RVP 7	285,000	218	50	42
New Tank 2640	Domed	Crude Oil RVP 7	500,000	260	64	55.5
New Tank 2641	Domed	Crude Oil RVP 7	500,000	260	64	55.5
New Tank 2643	Domed	Water/Crude	10,000	40	48	8.5

5. OPERATING SCHEDULE

	NORMAL	MAXIMUM
Hours/Day	24	24
Days/Week	7	7
Weeks/Year	52	52

6. EMISSION CALCULATIONS

The calculations of emissions for the new tanks and the modified tanks were based on throughputs of 2,400,000 and 1,500,000 BBL per month, respectively. In the case of the water draw tank which is a batch operation, the equipment is sized much larger than what would be expected to be recovered from the crude oil on a steady state basis. However, emissions were still calculated using the larger equipment rating to allow for maximum turnovers. The Table 2 lists the throughputs and annual turnovers of each tank being permitted.

TABLE 2
Fill and Pump Out Specifications

Tank Number	Fill Type	Throughput (BBL/mo)	Annual Turnovers
Modified Tank 510	Pier "T"	1,500,000	64
Modified Tank 511	Pier "T"	1,500,000	64
New Tank 2640	Pier "T"	2,400,000	58
New Tank 2641	Pier "T"	2,400,000	58
New Tank 2643	Pumped	64,000	77

The emissions for the tanks were calculated with the EPA TANKS 4.0.9d emissions model using a crude speciation for crude oil with a Reid Vapor Pressure of 7 (true vapor pressure 11, see Figure 4). The peak daily emission rate was calculated by taking the maximum monthly value and converting to a daily rate. The new 575,000 BBL tanks will use 4" legs instead of the standard 3" legs. Since there are no established emission factors for non-standard sized legs, emissions were scaled based on the difference in circumference between the 3" legs and 4" legs. The fugitive emissions from components were calculated using the SCAQMD correlation equations. The emission calculations can be found in Attachment B.

7. EVALUATION AND RULE REVIEW

The proposed Project is designed to comply with the standards contained in the applicable State and Federal Rules and Regulations. The following provides a brief summary of the applicable regulations.

STATE REGULATIONS

Rule 301 – Permit Fees

Per the requirements of SCAQMD Rule 301, the application fee for the tanks is $13,760.24 (Schedule C – Storage Tank, with External Floating Roof). Expedited permit processing has been requested and an additional $6,880.13 will be submitted with the permit application fee. The total application and expedited fee for the permit application is $22,429.49.

Rule 403 – Fugitive Dust

The construction activities of the proposed project are regulated under SCAQMD Rule 403 which include requirements to minimize fugitive dust using best available control measures that include applying water or chemical stabilizers to active construction sites/unpaved roads, covering all haul vehicles, and so forth.

Rule 463 – Organic Liquid Storage

The crude storage tanks are regulated under SCAQMD Rule 463, which includes requirements to minimize fugitive VOC using best available control measures that include tanks construction standards.

Rule 466 – Pumps and Compressors

Rule 466 establishes inspection, tagging, and maintenance requirements for pumps and compressors. Pumps and compressors associated with all tanks will be included in the LARC Rule 1173 compliance program and will, therefore, comply with Rule 466.

Rule 466.1 – Valves and Flanges

Rule 466.1 establishes inspection, tagging, and maintenance requirements for valves and flanges. Valves and flanges associated with all tanks will be included in the LARC Rule 1173 monitoring program and will, therefore, comply with Rule 466.1.

Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants

The LARC currently complies with Rule 1173 and has a monitoring program for leaks. The new tanks will be incorporated into the existing plan.

Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities

Rule 1178 establishes tanks standards to control fugitive VOC emissions. The new and modified tanks associated with proposed Project will comply with Rule 1178.

Regulation XIII – New Source Review

The tanks are subject to Regulation XIII and are subject to requirements to provide emission offsets. Tanks R510 and R511 were permitted pursuant to Rule 213 with an NSR for Tank R510 identified as 103.7 lbs/day (See Attachment C). Since Tank R511 is identical to Tank R510, the total NSR balance for the tanks should be 207.4 lbs/day Pursuant to Rule 1304(c)(2) a concurrent emissions reduction can be used in lieu of providing offsets for the new equipment. As shown in Table 3, no additional offsets are required for this project.

TABLE 3
Emission Reduction Credits Summary

Tank No.	Emissions (lbs/day)
Post Project Emissions	
Existing Tank 510 Crude Tank	12.50
Existing Tank 511 Crude Tank	12.50
New Tank 2640 Crude Tank	15.89
New Tank 2641 Crude Tank	15.89
New Tank 2643 Water Draw Tank	2.54
Fugitive Emissions	11.46
Total Project Emissions	70.78
NSR Balance for Tanks 510 and 511	207.4
Offsets Required	0

Rule 1401 – New Source Review for Toxic Air Contaminants

The tanks will store crude oil which contains chemicals listed under SCAQMD Rule 1401 and considered to be toxic air contaminants. The increase in toxic air contaminants is below the Rule 1401 screening thresholds for each of the four tanks. The Rule 1401 screening analyses are included in Attachment D.

Regulation XX - RECLAIM

The facility is subject to RECLAIM, however, the project only generates VOC emissions, which is not a RECLAIM pollutant. Therefore, no RECLAIM emissions are emitted from this project.

Regulation XXX - Title V Permits

The facility is a Title V facility. Permit modification applications are included in this application package to modify the facility Title V permit. The Title V permit modification qualifies as a significant permit revision pursuant to SCAQMD Rule 3000(b)(31)(I).

FEDERAL REGULATIONS

The federal regulations applicable to the new tanks are as follows:

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

40 CFR 61 Subpart V – National Emission Standards for Equipment Leaks (Fugitive Emission Sources)
40 CRF 61 subpart FF – National Emission Standards for Benzene Waste Operations
40 CFR 63 Subpart H – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks
40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

The federal regulations, while not identical to the state regulations, are similar to state regulations. The new and modified tanks are designed to comply with BACT requirements, the SCAQMD rules and regulations, and federal regulations. Therefore, the new and modified tanks are expected to comply with applicable subparts of the federal regulations.

8. PROPOSED PERMIT CONDITIONS

Below are the proposed permit conditions for throughput and monitoring of the tanks. These conditions should replace condition C1.17 for existing Tanks 510 and 511, and should read:

> *The operator shall limit the throughput to no more than 1,500,000 barrel(s) in any one calendar month.*
>
> *The operator shall calculate the throughput, in barrels, by the following equation:*
>
> > *0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.*
>
> *The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.*
>
> *The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.*
>
> *The operator shall keep adequate records to show compliance with the limitations specified in this permit.*

The conditions for new Tanks 2640 and 2641 should read:

> *The operator shall limit the throughput to no more than 2,400,000 barrel(s) in any one calendar month.*

The operator shall calculate the throughput, in barrels, by the following equation:

> *0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.*

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

The conditions for new Tanks 2643 should read:

The operator shall limit the throughput to no more than 64,000 barrel(s) in any one calendar month.

The operator shall calculate the throughput, in barrels, by the following equation:

> *0.14 x d x d x l, where d is the diameter of the tank in feet based on the tank strapping chart and l is the total vertical one-way roof travel in feet per month.*

The operator shall install and maintain an automatic tank level gauge (ATLG) and recorder to continuously record the vertical movement of the roof. For the purpose of this condition, continuous recording is defined as once per hour.

The operator shall calculate the total one-way roof movement, in feet, on a daily and monthly basis.

The operator shall keep adequate records to show compliance with the limitations specified in this permit.

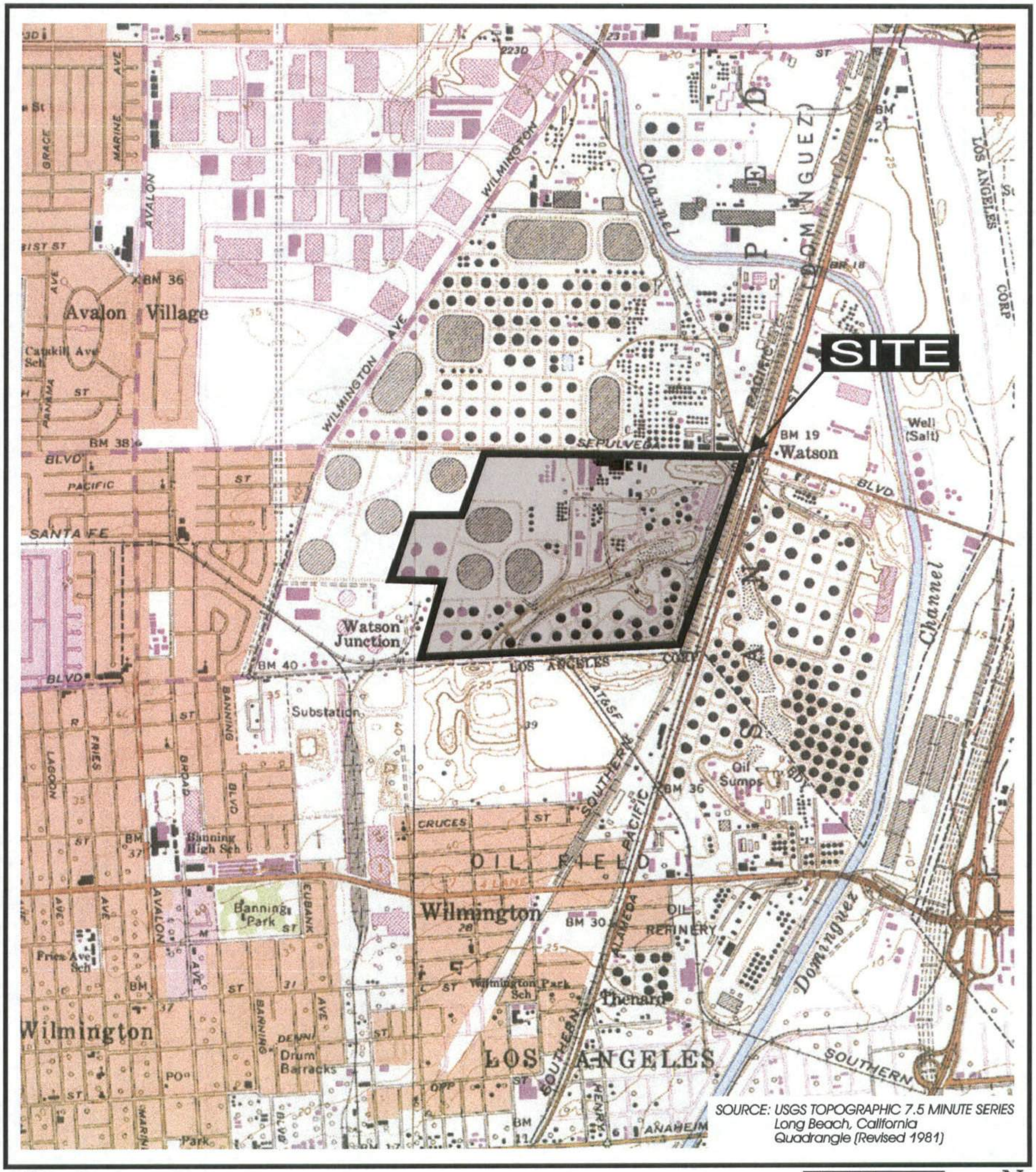
9. CONFIDENTIALITY

Certain information supplied on the attached sheets concerning process operating conditions, material balances, and process descriptions constitutes confidential and proprietary information under Government Code Section 6254.7. Philips 66 justifies classification of such data as trade secrets because the information contains production data and operating procedures, and therefore would potentially release competitively sensitive information, which would be of considerable value to competitors. Therefore, we request that all such data be handled in confidence.

M:\MC\2778 P66 - Crude Capacity Project\Permit Applications\rev4

ATTACHMENT A

Figures



Environmental Audit, Inc.

SITE LOCATION MAP
Phillips 66 Los Angeles Refinery
Carson Plant

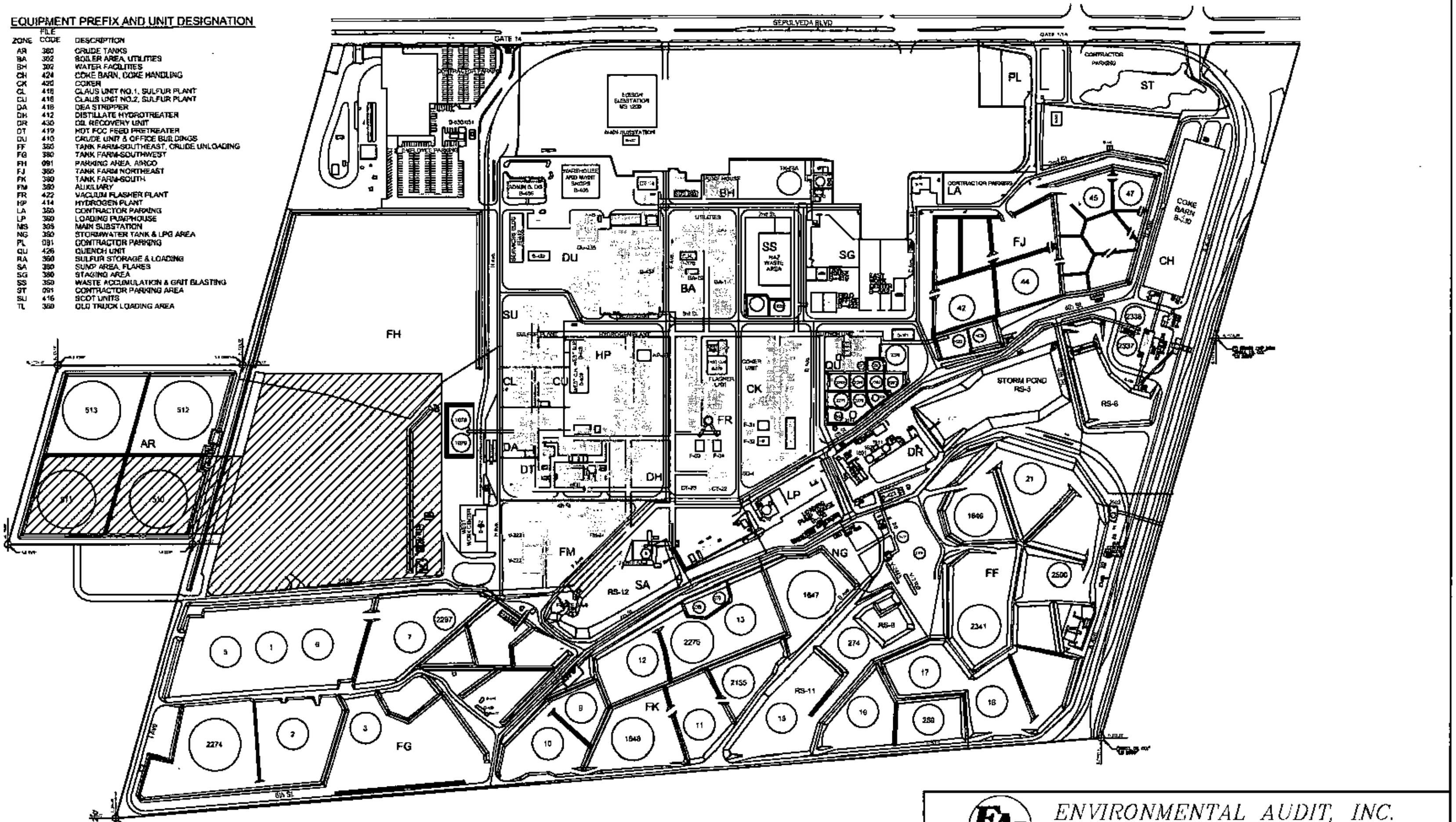
Project No. 2778

Figure 1

N:\2778\SiteLocMap (Carson).cdr

EQUIPMENT PREFIX AND UNIT DESIGNATION

ZONE	FILE CODE	DESCRIPTION
AR	360	CRUDE TANKS
BA	302	BOILER AREA, UTILITIES
BH	302	WATER FACILITIES
CH	424	COKE BARN, COKE HANDLING
CK	420	COKER
CL	416	CLAUS UNIT NO.1, SULFUR PLANT
CU	416	CLAUS UNIT NO.2, SULFUR PLANT
DA	416	DEA STRIPPER
DH	412	DISTILLATE HYDROTREATER
DR	430	OIL RECOVERY UNIT
DT	419	HOT FCC FEED PRETREATER
DU	410	CRUDE UNIT & OFFICE BUILDINGS
FF	360	TANK FARM-SOUTHEAST, CRUDE UNLOADING
FG	380	TANK FARM-SOUTHWEST
FH	091	PARKING AREA, ARCO
FJ	360	TANK FARM NORTHEAST
FK	380	TANK FARM-SOUTH
FM	380	AUXILIARY
FR	422	VACUUM FLASHER PLANT
HP	414	HYDROGEN PLANT
LA	350	CONTRACTOR PARKING
LP	360	LOADING PUMPHOUSE
MS	305	MAIN SUBSTATION
NG	360	STORMWATER TANK & LPG AREA
PL	091	CONTRACTOR PARKING
QU	426	QUENCH UNIT
RA	360	SULFUR STORAGE & LOADING
SA	380	SUMP AREA, FLARES
SG	380	STAGING AREA
SS	350	WASTE ACCUMULATION & GRIT BLASTING
ST	091	CONTRACTOR PARKING AREA
SU	416	SCOT UNITS
TL	360	OLD TRUCK LOADING AREA



LEGEND:

(13) NUMBERS IN AND AROUND OBJECTS REPRESENT INDIVIDUAL TANK NUMBERS

PROPOSED PROJECT AREA

NORTH

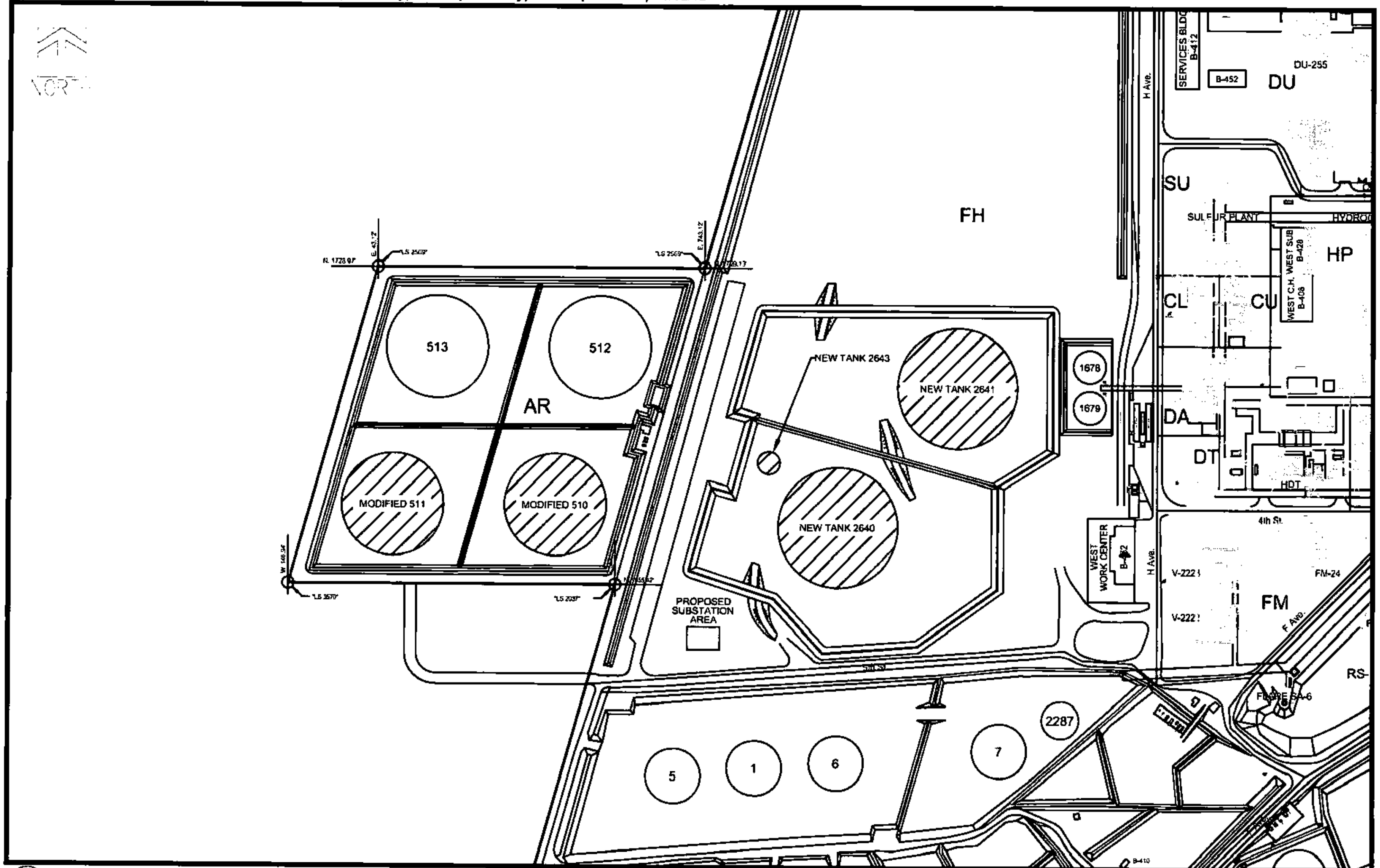
0 400'
SCALE

ENVIRONMENTAL AUDIT, INC.
1000-A ORTEGA WAY • PLACENTIA, CA 92870-7125
714/632-8521 • FAX 714/632-6754

SITE PLAN - PHILLIPS 66 LOS ANGELES REFINERY

DRAWN BY	DATE CREATED	
M.B.	11/19/03	CARSON PLANT
CHECKED	LAST REV	1520 E. SEPULVEDA BLVD.
DBS	06/11/12	Carson, California
SIZE		
17x11		
FILE NAME		
I:\2778\Site Plan Carson Plant (rev.2)		Figure 2

I:\2778\Proposed Project (rev.2b) (Created) 11/19/03 (Drawn By) A.S.K. (Check By) S.A.B. (Last Rev.) 10/02/12

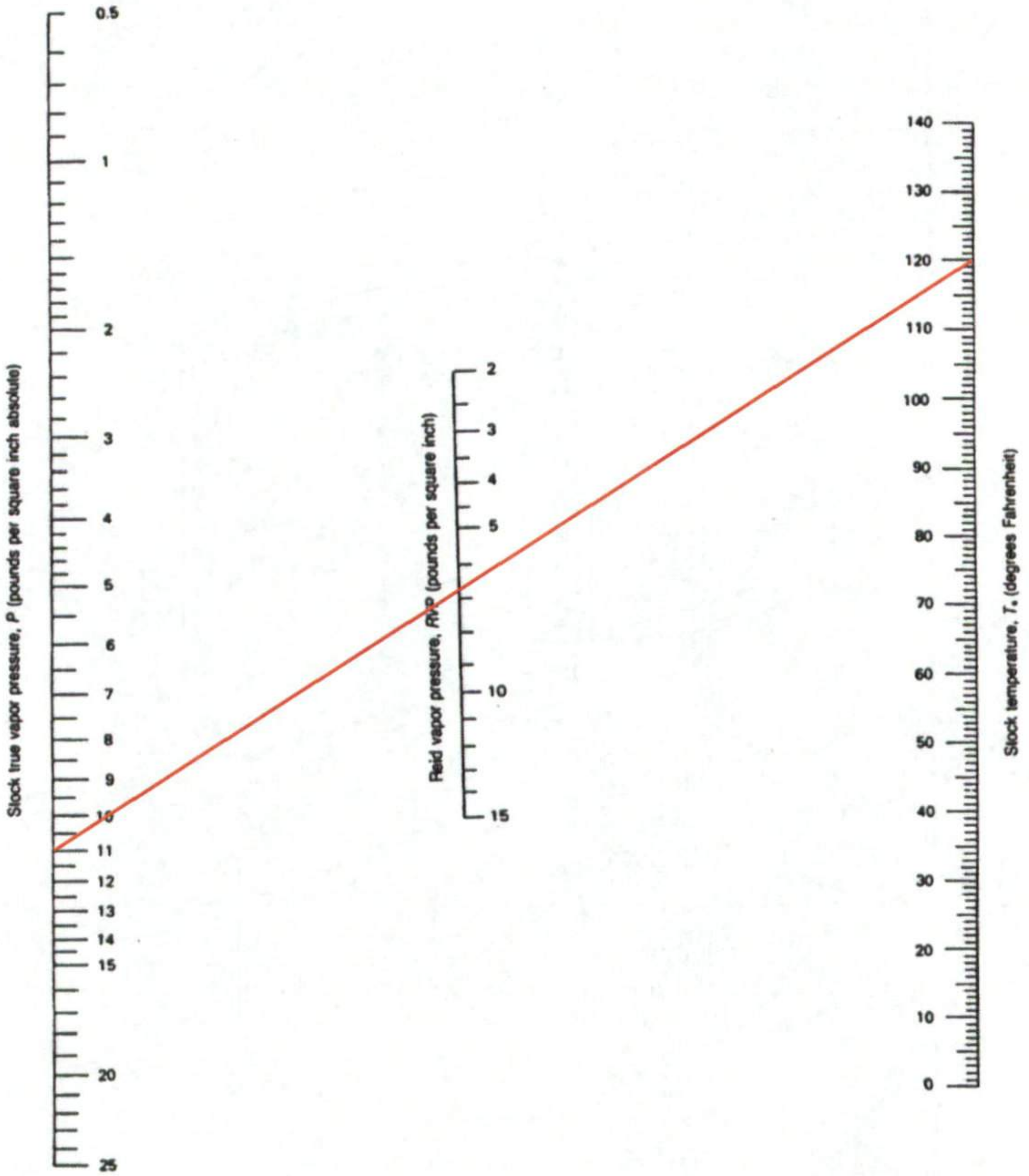


Environmental Audit, Inc.

PROPOSED PROJECT PLAN
Phillips 66 Los Angeles Refinery
Carson Plant

Project No. 2778

Figure 3



True vapor pressure of crude oils with a Reid vapor pressure of 2 to 15 pounds per square inch.

SOURCE: AP42 Figure 7.1-13a (November 2006)

Environmental Audit, Inc.

Nomograph of Crude Oil Vapor Pressure

ATTACHMENT B

Emission Calculations

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2640**

						Correlation Equation (CE) Factor (500 ppm)		
Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	148	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	7	4.55	0	31.82
		Light Liquid (4)	0	0	32	4.55	0	145.46
		Heavy Liquid (5)	0	0		4.55	0	-
		> 8 inches	0	0			0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	1	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	4	46.83	-	187.30
	Single Mechanical Seals	Heavy Liquid (5)	0	0		46.83	0	
Compressors		Gas / Vapor	0	0		9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	169	6.99	-	1,181.34
Connectors		All	0	0	90	2.86	-	257.52
Pressure Relief Valves		All	0	0	2		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	3	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	8	9.09	-	
Total Emissions		lb/year					-	1,803
		lbs/day					0	4.94

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2641**

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm)		
						Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	148	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	7	4.55	0	31.82
		Light Liquid (4)	0	0	32	4.55	0	145.46
		Heavy Liquid (5)	0	0		4.55	0	-
		> 6 inches	0	0			0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	1	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	4	46.83	-	187.30
	Single Mechanical Seals	Heavy Liquid (5)	0	0		46.83	0	
Compressors		Gas / Vapor	0	0		9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	169	6.99	-	1,181.34
Connectors		All	0	0	90	2.86	-	257.52
Pressure Relief Valves		All	0	0	2		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	3	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	8	9.09	-	
Total Emissions		lb/year					-	1,803
		lbs/day					0	4.94

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Component Count

Process Unit: **Philips 66 Carson Plant New Crude Tank 2643**

Source Unit		Service	No. Of Existing Components (1)	No. of Existing Components to be Removed (2)	No. of New Components to be Installed (3)	Correlation Equation (CE) Factor (500 ppm)		
						Correlation Equation Factor 500 ppm Screening Value (lbs/year)	Pre Mod Emissions Based on Correlation 500 ppm Screening Value (lbs/year)	Post Modification Emissions based on 500 ppm Correlation Equation Factor (lbs/year)
Valves	Sealed Bellows	All	0	0	45	0.00	0	0
	SCAQMD Approved I&M Program	Gas / Vapor	0	0	0	4.55	0	-
		Light Liquid (4)	0	0	10	4.55	0	45.46
		Heavy Liquid (5)	0	0	0	4.55	0	-
		> 8 inches	0	0	0		0	-
Pumps	Sealless Type	Light Liquid (4)	0	0	0	0.00	0	-
	Double Mechanical Seals or Equivalent Seals	Light Liquid (4)	0	0	0	46.83	-	-
	Single Mechanical Seals	Heavy Liquid (5)	0	0	0	46.83	0	
Compressors		Gas / Vapor	0	0	0	9.09	-	
Flanges (ANSI 16.5-1988)		All	0	0	72	6.99	-	503.29
Connectors		All	0	0	9	2.86	-	25.75
Pressure Relief Valves		All	0	0	0		0	-
Process Drains with P-Trap or Seal Pot		All	0	0	0	9.09	-	
Other (including fittings, hatches, sight-glasses, and meters)		All	0	0	0	9.09	-	
Total Emissions		lb/year					-	575
		lbs/day					0	1.57

-1 Any component currently installed prior to the modification.

-2 Any component to be removed due to modification.

-3 Any new component proposed to be installed due to the modification; this also includes new components to be installed to replace existing components.

-4 Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume. - used single mechanical seal EF

-5 Heavy Liquid: streams with a vapor pressure equal to or less than that of kerosene (< 0.1 psia @ 100°F or 689 Pa @ 38°C), based on the most volatile class present at 20% by volume.

-6 Emission Factors were developed using actual emissions for 10 quarters from Q3, 2005 through Q4, 2007 for Cleans Fuel Area and using a factor of 2 to the actual emissions.

Philips 66 Carson Plant
Crude Tank Fugitive Emissions

Chemical	Crude Vapor Wt%	Tank 2640 Emissions lb/yr	Tank 2640 Emissions lb/day	Tank 2640 Emissions lb/hr	Tank 2641 Emissions lb/yr	Tank 2641 Emissions lb/day	Tank 2641 Emissions lb/hr	Tank 2643 Emissions lb/yr	Tank 2643 Emissions lb/day	Tank 2643 Emissions lb/hr
Benzene	2.83	51.09	0.14	0.0058	51.09	0.14	0.0058	16.28	0.04	0.0019
PACs (Chrysene)	0.00	0.00	0.00	0.0000	0.00	0.00	0.0000	0.00	0.00	0.0000
Cresol (mixed isomers)	0.00	0.00	0.00	0.0000	0.00	0.00	0.0000	0.00	0.00	0.0000
Ethylbenzene	0.13	2.26	0.01	0.0003	2.26	0.01	0.0003	0.72	0.00	0.0001
n-Hexane	38.55	695.18	1.90	0.0794	695.18	1.90	0.0794	221.45	0.61	0.0253
Naphthalene	0.00	0.02	0.00	0.0000	0.02	0.00	0.0000	0.00	0.00	0.0000
Phenol	0.00	0.00	0.00	0.0000	0.00	0.00	0.0000	0.00	0.00	0.0000
Toluene	1.01	18.25	0.05	0.0021	18.25	0.05	0.0021	5.81	0.02	0.0007
Cumene	0.00	0.00	0.00	0.0000	0.00	0.00	0.0000	0.00	0.00	0.0000
Xylene (mixed isomers)	0.19	3.49	0.01	0.0004	3.49	0.01	0.0004	1.11	0.00	0.0001
Cyclohexane	19.14	345.26	0.95	0.0394	345.26	0.95	0.0394	109.99	0.30	0.0126
1,2,4-Trimethylbenzene	0.01	0.22	0.00	0.0000	0.22	0.00	0.0000	0.07	0.00	0.0000
Total VOC	100.00	1803.45	4.94	0.2059	1803.45	4.94	0.2059	574.50	1.57	0.0656

Philips 66 Carson Plant
Crude Tank Tank Loss Emissions

	Tank 2640/2641[1]			Tank 2643			Tank R510/R511		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	8.19	0.0224	0.0009	1.30	0.0036	0.0001	6.86	0.0188	0.0008
PACs (Chrysene)	0.09	0.0002	0.0000	0.02	0.0001	0.0000	0.07	0.0002	0.0000
Cresol (mixed isomers)	0.03	0.0001	0.0000	-	-	-	0.02	0.0001	0.0000
Ethylbenzene	6.83	0.0187	0.0008	1.17	0.0032	0.0001	5.12	0.0140	0.0006
n-Hexane	59.22	0.1622	0.0068	9.07	0.0248	0.0010	47.82	0.1310	0.0055
Naphthalene	4.07	0.0112	0.0005	0.71	0.0019	0.0001	3.03	0.0083	0.0003
Phenol	0.01	0.0000	0.0000	-	-	-	0.01	0.0000	0.0000
Toluene	27.93	0.0765	0.0032	4.70	0.0129	0.0005	21.20	0.0581	0.0024
Xylene (mixed isomers)	43.05	0.1179	0.0049	7.40	0.0203	0.0008	32.20	0.0882	0.0037
Cumene	0.11	0.0003	0.0000	0.02	0.0001	0.0000	0.08	0.0002	0.0000
Cyclohexane	42.26	0.1158	0.0048	6.75	0.0185	0.0008	33.24	0.0911	0.0038
1,2,4-Trimethylbenzene	12.59	0.0345	0.0014	2.18	0.0060	0.0002	9.37	0.0257	0.0011
Total VOC	5,654.53	15.4919	0.6455	906.11	2.4825	0.1034	4438.71	12.1608	0.5067

(1) Tank leg emissions scaled for 4" legs.

Philips 66 Carson Plant
Crude Tank Total Operational Emissions

	Tank 2640/2641			Tank 2643			Tank R510/R511		
Chemical	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr	Emissions lb/yr	Emissions lb/day	Emissions lb/hr
Benzene	59.28	0.1624	0.0068	17.58	0.0482	0.0020	6.86	0.0188	0.0008
PACs (Chrysene)	0.09	0.0002	0.0000	0.02	0.0001	0.0000	0.07	0.0002	0.0000
Cresol (mixed isomers)	0.03	0.0001	0.0000	0.00	0.0000	0.0000	0.02	0.0001	0.0000
Ethylbenzene	9.09	0.0249	0.0010	1.89	0.0052	0.0002	5.12	0.0140	0.0006
n-Hexane	754.40	2.0668	0.0861	230.52	0.6316	0.0263	47.82	0.1310	0.0055
Naphthalene	4.09	0.0112	0.0005	0.71	0.0020	0.0001	3.03	0.0083	0.0003
Phenol	0.01	0.0000	0.0000	0.00	0.0000	0.0000	0.01	0.0000	0.0000
Toluene	46.18	0.1265	0.0053	10.51	0.0288	0.0012	21.20	0.0581	0.0024
Xylene (mixed isomers)	43.05	0.1180	0.0049	7.40	0.0203	0.0008	32.20	0.0882	0.0037
Cumene	3.60	0.0099	0.0004	1.13	0.0031	0.0001	0.08	0.0002	0.0000
Cyclohexane	387.52	1.0617	0.0442	116.74	0.3198	0.0133	33.24	0.0911	0.0038
1,2,4-Trimethylbenzene	12.81	0.0351	0.0015	2.25	0.0062	0.0003	9.37	0.0257	0.0011
Total VOC	7,457.98	20.4328	0.8514	1,480.61	4.0565	0.1690	4,438.71	12.1608	0.5067

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	2640/2641
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity)

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,000,000.00
Turnovers:	57.60

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

B-7

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Attachment B

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	260
Automatic Gauge Float Well/Bolted Cover, Gasketed	3
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format

Liquid Contents of Storage Tank

2640/2641 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP 7)	Jan	61.79	56.79	66.79	64.33	4.7172	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.0663	N/A	N/A	49.4256	0.9618	0.9728	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Feb	62.78	57.67	67.88	64.33	4.8016	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0157	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.1562	N/A	N/A	49.4204	0.9618	0.9725	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Mar	63.78	58.57	68.99	64.33	4.8887	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0158	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2489	N/A	N/A	49.4151	0.9618	0.9723	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Apr	65.70	59.89	71.51	64.33	5.0590	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79

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Attachment B

Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0077	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0160	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.4303	N/A	N/A	49.4048	0.9618	0.9718	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	May	67.27	61.79	72.76	64.33	5.2015	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0162	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.5820	N/A	N/A	49.3964	0.9618	0.9714	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jun	68.98	63.35	74.61	64.33	5.3596	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0079	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0164	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.7502	N/A	N/A	49.3872	0.9618	0.9710	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jul	71.26	65.04	77.47	64.33	5.5770	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0167	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.9814	N/A	N/A	49.3749	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Aug	71.60	65.63	77.58	64.33	5.6104	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0017	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21

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Attachment B

Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0168	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						6.0170	N/A	N/A	49.3730	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Sep	70.17	64.65	75.68	64.33	5.4719	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0080	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0166	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.8697	N/A	N/A	49.3808	0.9618	0.9707	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Oct	67.76	62.48	73.04	64.33	5.2463	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0163	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.6296	N/A	N/A	49.3938	0.9618	0.9713	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Nov	64.31	59.22	69.40	64.33	4.9350	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0076	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0159	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2983	N/A	N/A	49.4123	0.9618	0.9722	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Dec	61.76	56.83	66.70	64.33	4.7152	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3487	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.0641	N/A	N/A	49.4257	0.9618	0.9728	215.18	

Xylenes (mixed isomers)	0.0961	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2640/2641 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	25.0698	25.6162	26.1846	27.3105	28.2670	29.3441	30.8538	31.0891	30.1202	28.5702	26.4889	25.0567
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Pressure at Daily Average Liquid												
Surface Temperature (psia):	4.7172	4.8016	4.8887	5.0590	5.2015	5.3596	5.5770	5.6104	5.4719	5.2463	4.9350	4.7152
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166
Net Throughput (gal/mo.):	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	53.9435	55.1193	56.3422	58.7649	60.8229	63.1405	66.3890	66.8955	64.8106	61.4754	56.9969	53.9153
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700	335.6700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	449.8299	451.5521	453.3435	456.8921	459.9065	463.3012	468.0593	468.8012	465.7474	460.8622	454.3024	449.7886

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6	6.20	1.20	0.94	79.6762
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	29.9856
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	1.0067
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	260	0.82	0.53	0.14	456.6386
Automatic Gauge Float Well/Bolted Cover, Gasketed	3	2.80	0.00	0.00	17.9914
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	13.7077
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	119.9426

TANKS 4.0.9d

Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640/2641 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 7)	333.97	4,449.80	718.62	0.00	5,502.39
1,2,4-Trimethylbenzene	0.02	12.51	0.04	0.00	12.58
Benzene	0.53	6.29	1.13	0.00	7.95
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.11
Cyclohexene	2.59	32.93	5.57	0.00	41.08
Ethylbenzene	0.05	6.64	0.12	0.00	6.81
Hexane (-n)	5.40	39.75	11.61	0.00	56.76
Naphthalene	0.00	4.07	0.00	0.00	4.07
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.62	25.69	1.34	0.00	27.65
Unidentified Components	324.48	4,279.66	698.18	0.00	5,302.33
Xylenes (mixed isomers)	0.29	42.01	0.62	0.00	42.92

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

B-15

Attachment B

Identification

User Identification:	2640 legless
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	500000 bbl domed tank (working capacity) - Legless

Tank Dimensions

Diameter (ft):	260.00
Volume (gallons):	21,000,000.00
Turnovers:	57.60

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Automatic Gauge Float Well/Bolted Cover, Gasketed	3
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

2640 legless - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP 7)	Jan	61.79	56.79	66.79	64.33	4.7172	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.0663	N/A	N/A	49.4256	0.9618	0.9728	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Feb	62.78	57.67	67.88	64.33	4.8016	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0157	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.1562	N/A	N/A	49.4204	0.9618	0.9725	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Mar	63.78	58.57	68.99	64.33	4.8887	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0158	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2489	N/A	N/A	49.4151	0.9618	0.9723	215.18	

Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Apr	65.70	59.89	71.51	64.33	5.0590	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0077	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0160	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.4303	N/A	N/A	49.4048	0.9618	0.9718	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	May	67.27	61.79	72.76	64.33	5.2015	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0162	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.5820	N/A	N/A	49.3964	0.9618	0.9714	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jun	68.98	63.35	74.61	64.33	5.3596	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0079	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0164	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.7502	N/A	N/A	49.3872	0.9618	0.9710	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jul	71.26	65.04	77.47	64.33	5.5770	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0167	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.9814	N/A	N/A	49.3749	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Aug	71.60	65.63	77.58	64.33	5.6104	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0017	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439

B-17

Attachment B

B-18

Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0168	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						6.0170	N/A	N/A	49.3730	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Sep	70.17	64.65	75.68	64.33	5.4719	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5361	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0080	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0166	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.8697	N/A	N/A	49.3808	0.9618	0.9707	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Oct	67.76	62.48	73.04	64.33	5.2463	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4426	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0163	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.6296	N/A	N/A	49.3938	0.9618	0.9713	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Nov	64.31	59.22	69.40	64.33	4.9350	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0076	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0159	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2983	N/A	N/A	49.4123	0.9618	0.9722	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Dec	61.76	56.83	66.70	64.33	4.7152	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Attachment B

Naphthalene	0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol	0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene	0.3487	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components	5.0641	N/A	N/A	49.4257	0.9618	0.9728	215.18	
Xylenes (mixed isomers)	0.0981	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

2640 legless - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	25.0698	25.6162	26.1846	27.3105	28.2670	29.3441	30.8538	31.0891	30.1202	28.5702	26.4889	25.0567
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	4.7172	4.8016	4.8887	5.0590	5.2015	5.3598	5.5770	5.6104	5.4719	5.2463	4.9350	4.7152
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166	370.8166
Net Throughput (gal/mo.):	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000	100,800,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000	260.0000
Roof Fitting Losses (lb):	19.6814	20.1104	20.5566	21.4405	22.1914	23.0370	24.2222	24.4070	23.6463	22.4295	20.7955	19.6711
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700	122.4700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	415.5678	416.5433	417.5578	419.5677	421.2750	423.1976	425.8925	426.3127	424.5831	421.8163	418.1009	415.5445

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	6	6.20	1.20	0.94	79.6762
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	29.9856
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	1.0067
Automatic Gauge Float Well/Bolted Cover, Gasketed	3	2.80	0.00	0.00	17.9914
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	4	1.60	0.00	0.00	13.7077
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	119.9426

TANKS 4.0.9d

Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

2640 legless - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 7)	333.97	4,449.80	262.19	0.00	5,045.96
1,2,4-Trimethylbenzene	0.02	12.51	0.02	0.00	12.55
Benzene	0.53	6.29	0.41	0.00	7.23
Chrysene	0.00	0.09	0.00	0.00	0.09
Cresol (-m)	0.00	0.03	0.00	0.00	0.03
Cumene	0.00	0.11	0.00	0.00	0.11
Cyclohexene	2.59	32.93	2.03	0.00	37.55
Ethylbenzene	0.05	6.64	0.04	0.00	6.74
Hexane (-n)	5.40	39.75	4.24	0.00	49.39
Naphthalene	0.00	4.07	0.00	0.00	4.07
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	0.62	25.69	0.49	0.00	26.80
Unidentified Components	324.48	4,279.66	254.73	0.00	4,858.87
Xylenes (mixed isomers)	0.29	42.01	0.22	0.00	42.53

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	T2643
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	10000bbl (working capacity) domed water surge tank

Tank Dimensions

Diameter (ft):	40.00
Volume (gallons):	420,000.00
Turnovers:	76.80

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	15

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

T2643 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP 7)	Jan	61.79	56.79	66.79	64.33	4.7172	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.0663	N/A	N/A	49.4256	0.9618	0.9728	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Feb	62.78	57.67	67.88	64.33	4.8016	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0157	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.1562	N/A	N/A	49.4204	0.9618	0.9725	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Mar	63.78	58.57	68.99	64.33	4.8887	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0158	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2489	N/A	N/A	49.4151	0.9618	0.9723	215.18	

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Attachment B

Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Apr	65.70	59.89	71.51	64.33	5.0590	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0258	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0077	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0160	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.4303	N/A	N/A	49.4048	0.9618	0.9718	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	May	67.27	61.79	72.76	64.33	5.2015	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0162	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.5820	N/A	N/A	49.3964	0.9618	0.9714	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jun	68.98	63.35	74.61	64.33	5.3596	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0079	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0164	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.7502	N/A	N/A	49.3872	0.9618	0.9710	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jul	71.26	65.04	77.47	64.33	5.5770	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5631	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0167	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.9814	N/A	N/A	49.3749	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Aug	71.60	65.63	77.58	64.33	5.6104	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0017	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439

Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0168	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						6.0170	N/A	N/A	49.3730	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Sep	70.17	64.65	75.68	64.33	5.4719	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0080	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0166	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.8697	N/A	N/A	49.3808	0.9618	0.9707	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Oct	67.76	62.48	73.04	64.33	5.2463	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0163	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.6296	N/A	N/A	49.3938	0.9618	0.9713	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Nov	64.31	59.22	69.40	64.33	4.9350	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0076	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0159	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2983	N/A	N/A	49.4123	0.9618	0.9722	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Dec	61.76	56.83	66.70	64.33	4.7152	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41

Naphthalene	0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol	0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene	0.3487	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components	5.0641	N/A	N/A	49.4257	0.9618	0.9728	215.18	
Xylenes (mixed isomers)	0.0961	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

T2643 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	3.8569	3.9410	4.0284	4.2016	4.3488	4.5145	4.7467	4.7829	4.6339	4.3954	4.0752	3.8549
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	4.7172	4.8016	4.8887	5.0590	5.2015	5.3598	5.5770	5.6104	5.4719	5.2463	4.9350	4.7152
Tank Diameter (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749	64.2749
Net Throughput (gal/mo.):	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000	2,688,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Roof Fitting Losses (lb):	6.2626	6.3991	6.5411	6.8224	7.0613	7.3304	7.7075	7.7663	7.5243	7.1371	6.6171	6.2594
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700	38.9700
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	74.3944	74.6150	74.8444	75.2989	75.6850	76.1197	76.7291	76.8241	76.4330	75.8074	74.9672	74.3891

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	6.8539
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	5.9971
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	13.2794
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	29.9856
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	1.0067
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	15	0.82	0.53	0.14	26.3445

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

T2643 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 7)	51.38	771.30	83.43	0.00	906.11
1,2,4-Trimethylbenzene	0.00	2.17	0.00	0.00	2.18
Benzene	0.08	1.09	0.13	0.00	1.30
Chrysene	0.00	0.02	0.00	0.00	0.02
Cresol (-m)	0.00	0.00	0.00	0.00	0.00
Cumene	0.00	0.02	0.00	0.00	0.02
Cyclohexene	0.40	5.71	0.65	0.00	6.75
Ethylbenzene	0.01	1.15	0.01	0.00	1.17
Hexane (-n)	0.83	6.89	1.35	0.00	9.07
Naphthalene	0.00	0.71	0.00	0.00	0.71
Phenol	0.00	0.00	0.00	0.00	0.00
Toluene	0.10	4.45	0.16	0.00	4.70
Unidentified Components	49.92	741.81	81.06	0.00	872.78
Xylenes (mixed isomers)	0.04	7.28	0.07	0.00	7.40

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Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	R510/511
City:	Long Beach
State:	California
Company:	
Type of Tank:	Domed External Floating Roof Tank
Description:	285000 bbl tank (working capacity)

Tank Dimensions

Diameter (ft):	218.60
Volume (gallons):	11,970,000.00
Turnovers:	63.16

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Pontoon
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Shoe-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2
Roof Drain (3-in. Diameter)/90% Closed	1
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77
Automatic Gauge Float Well/Bolted Cover, Gasketed	2
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1

Meterological Data used in Emissions Calculations: Long Beach, California (Avg Atmospheric Pressure = 14.7 psia)

TANKS 4.0.9d

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Attachment B

Emissions Report - Detail Format
Liquid Contents of Storage Tank

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude Oil (RVP 7)	Jan	61.79	56.79	66.79	64.33	4.7172	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2270	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1519	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1155	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0042	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3490	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.0663	N/A	N/A	49.4256	0.9618	0.9728	215.18	
Xylenes (mixed isomers)						0.0962	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Feb	62.78	57.67	67.88	64.33	4.8016	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0228	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2607	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0016	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0533	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1832	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1195	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0558	N/A	N/A	86.1700	0.0089	0.0157	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0028	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0032	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3597	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.1562	N/A	N/A	49.4204	0.9618	0.9725	215.18	
Xylenes (mixed isomers)						0.0996	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Mar	63.78	58.57	68.99	64.33	4.8887	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0237	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2957	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0553	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2157	N/A	N/A	82.1500	0.0074	0.0075	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1236	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1093	N/A	N/A	86.1700	0.0089	0.0158	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0029	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0034	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3710	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2489	N/A	N/A	49.4151	0.9618	0.9723	215.18	
Xylenes (mixed isomers)						0.1031	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Apr	65.70	59.89	71.51	64.33	5.0590	N/A	N/A	50.0000			205.00	Option 4: RVP=7

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Attachment B

1,2,4-Trimethylbenzene						0.0256	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3652	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0019	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0594	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2800	N/A	N/A	82.1500	0.0074	0.0077	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1320	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.2152	N/A	N/A	86.1700	0.0089	0.0160	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0032	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0038	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3934	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.4303	N/A	N/A	49.4048	0.9618	0.9718	215.18	
Xylenes (mixed isomers)						0.1101	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	May	67.27	61.79	72.76	64.33	5.2015	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0272	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4241	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0020	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0629	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3346	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1392	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3049	N/A	N/A	86.1700	0.0089	0.0162	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0034	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0041	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4125	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.5820	N/A	N/A	49.3984	0.9618	0.9714	215.18	
Xylenes (mixed isomers)						0.1162	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jun	68.98	63.35	74.61	64.33	5.3596	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0291	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4904	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0022	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0668	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3960	N/A	N/A	82.1500	0.0074	0.0079	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1474	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4054	N/A	N/A	86.1700	0.0089	0.0164	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0037	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0045	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4341	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.7502	N/A	N/A	49.3872	0.9618	0.9710	215.18	
Xylenes (mixed isomers)						0.1231	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Jul	71.26	65.04	77.47	64.33	5.5770	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0317	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5831	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0725	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4817	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1589	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5456	N/A	N/A	86.1700	0.0089	0.0167	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0040	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0050	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4645	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.9814	N/A	N/A	49.3749	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1329	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Aug	71.60	65.63	77.58	64.33	5.6104	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0321	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5975	N/A	N/A	78.1100	0.0014	0.0017	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0025	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0734	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777

Cyclohexene						1.4951	N/A	N/A	82.1500	0.0074	0.0081	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1608	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.5674	N/A	N/A	86.1700	0.0089	0.0168	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0041	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0051	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4693	N/A	N/A	92.1300	0.0058	0.0020	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						6.0170	N/A	N/A	49.3730	0.9618	0.9704	215.18	
Xylenes (mixed isomers)						0.1344	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Sep	70.17	64.65	75.68	64.33	5.4719	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0304	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.5381	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0023	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0697	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.4401	N/A	N/A	82.1500	0.0074	0.0080	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1533	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.4776	N/A	N/A	86.1700	0.0089	0.0166	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0039	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0048	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4497	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.8697	N/A	N/A	49.3808	0.9618	0.9707	215.18	
Xylenes (mixed isomers)						0.1281	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Oct	67.76	62.48	73.04	64.33	5.2463	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0277	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.4428	N/A	N/A	78.1100	0.0014	0.0016	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0021	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0640	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.3519	N/A	N/A	82.1500	0.0074	0.0078	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1415	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.3332	N/A	N/A	86.1700	0.0089	0.0163	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0035	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0042	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.4186	N/A	N/A	92.1300	0.0058	0.0019	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.6296	N/A	N/A	49.3938	0.9618	0.9713	215.18	
Xylenes (mixed isomers)						0.1181	N/A	N/A	106.1700	0.0094	0.0009	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Nov	64.31	59.22	69.40	64.33	4.9350	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0242	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.3145	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0017	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0564	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.2330	N/A	N/A	82.1500	0.0074	0.0076	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1259	N/A	N/A	106.1700	0.0015	0.0002	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.1380	N/A	N/A	86.1700	0.0089	0.0159	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0030	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0035	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57
Toluene						0.3770	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						5.2983	N/A	N/A	49.4123	0.9618	0.9722	215.18	
Xylenes (mixed isomers)						0.1050	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Crude Oil (RVP 7)	Dec	61.76	56.83	66.70	64.33	4.7152	N/A	N/A	50.0000			205.00	Option 4: RVP=7
1,2,4-Trimethylbenzene						0.0219	N/A	N/A	120.1900	0.0028	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2262	N/A	N/A	78.1100	0.0014	0.0015	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Chrysene						0.0000	N/A	N/A	228.2800	0.0000	0.0000	228.28	Option 2: A=7.30847, B=2609.83, C=148.439
Cresol (-m)						0.0015	N/A	N/A	108.1000	0.0000	0.0000	108.10	Option 2: A=7.508, B=1856.36, C=199.07
Cumene						0.0514	N/A	N/A	120.1900	0.0000	0.0000	120.19	Option 2: A=6.93666, B=1460.793, C=207.777
Cyclohexene						1.1512	N/A	N/A	82.1500	0.0074	0.0074	82.15	Option 2: A=6.8861, B=1229.973, C=224.1
Ethylbenzene						0.1154	N/A	N/A	106.1700	0.0015	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0030	N/A	N/A	86.1700	0.0089	0.0156	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Naphthalene						0.0027	N/A	N/A	128.2000	0.0009	0.0000	128.20	Option 2: A=7.3729, B=1968.36, C=222.61
Phenol						0.0031	N/A	N/A	94.1112	0.0000	0.0000	94.11	Option 2: A=7.1345, B=1516.07, C=174.57

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Attachment B

Toluene	0.3487	N/A	N/A	92.1300	0.0058	0.0018	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components	5.0841	N/A	N/A	49.4257	0.9818	0.9728	215.18	
Xylenes (mixed isomers)	0.0981	N/A	N/A	106.1700	0.0094	0.0008	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

R510/511 - Domed External Floating Roof Tank
Long Beach, California

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	56.2078	57.4329	58.7072	61.2316	63.3760	65.7909	69.1757	69.7034	67.5311	64.0559	59.3894	56.1784
Seal Factor A (lb-mole/ft-yr):	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000	0.3000
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Seal-related Wind Speed Exponent:	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000	1.6000
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	4.7172	4.8016	4.8887	5.0590	5.2015	5.3596	5.5770	5.6104	5.4719	5.2463	4.9350	4.7152
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Withdrawal Losses (lb):	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528	275.6528
Net Throughput (gal/mo.):	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000	63,000,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Average Organic Liquid Density (lb/gal):	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000	7.1000
Tank Diameter (ft):	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000	218.6000
Roof Fitting Losses (lb):	28.6824	29.3076	29.9579	31.2461	32.3403	33.5726	35.2999	35.5692	34.4606	32.6873	30.3060	28.6675
Value of Vapor Pressure Function:	0.0964	0.0985	0.1007	0.1050	0.1087	0.1129	0.1187	0.1196	0.1158	0.1099	0.1019	0.0964
Vapor Molecular Weight (lb/lb-mole):	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000
Product Factor:	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800	178.4800
Average Wind Speed (mph):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Losses (lb):	360.5430	362.3934	364.3179	368.1305	371.3691	375.0163	380.1283	380.9254	377.6445	372.3959	365.3482	360.4987

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	2	1.60	0.00	0.00	6.8539
Roof Drain (3-in. Diameter)/90% Closed	1	1.80	0.14	1.10	3.8553
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	34	1.30	0.08	0.65	94.6690
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	1.0067
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	2	6.20	1.20	0.94	26.5587
Ladder Well (36-in. Diam.)/Sliding Cover, Gasketed	1	56.00	0.00	0.00	119.9426
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	77	0.53	0.11	0.13	87.4082
Automatic Gauge Float Well/Bolted Cover, Gasketed	2	2.80	0.00	0.00	11.9943
Unslotted Guide-Pole Well/Gasketed sliding Cover, w. Wiper	1	14.00	3.70	0.78	29.9856

B-37

Attachment B

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

R510/511 - Domed External Floating Roof Tank
Long Beach, California

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 7)	748.78	3,307.83	382.10	0.00	4,438.71
1,2,4-Trimethylbenzene	0.04	9.30	0.02	0.00	9.37
Benzene	1.18	4.68	0.60	0.00	6.46
Chrysene	0.00	0.07	0.00	0.00	0.07
Cresol (-m)	0.00	0.02	0.00	0.00	0.02
Cumene	0.00	0.08	0.00	0.00	0.08
Cyclohexene	5.80	24.48	2.96	0.00	33.24
Ethylbenzene	0.12	4.94	0.06	0.00	5.12
Hexane (-n)	12.10	29.55	6.17	0.00	47.82
Naphthalene	0.00	3.03	0.00	0.00	3.03
Phenol	0.00	0.01	0.00	0.00	0.01
Toluene	1.40	19.09	0.71	0.00	21.20
Unidentified Components	727.49	3,181.36	371.23	0.00	4,280.09
Xylenes (mixed isomers)	0.64	31.23	0.33	0.00	32.20

ATTACHMENT C

Tank R510 NSR Balance

572-6321

November 13, 1980

Shell Oil Company
P. O. Box 6249
Carson, CA 90749

Attention: Environmental Conservation Manager

Dear Sir:

Transmitted herewith are the following permits authorizing you to operate the described equipment: 1622 EAST SEPULVEDA BLVD, CARSON

Permit No.	Application No.	Equipment Description
M-12199	C-18847	STORAGE TANK NO. R-513
M-12200	C-18848	STORAGE TANK NO. R-512
M-12251	C-18849	STORAGE TANK NO. R-511
M-12252	C-18850	STORAGE TANK NO. R-510

Rule 205 A person granted a permit under Rule 203 shall not operate or use any equipment unless the entire permit to operate or a legible facsimile of the entire permit is affixed upon the equipment in such a manner that the permit number, equipment description, and the specified operating conditions are clearly visible and accessible. In the event that the equipment is so constructed that the permit to operate or the legible facsimile cannot be so placed, the entire permit to operate or the legible facsimile of the entire permit shall be mounted so as to be clearly visible in an accessible place within 8 meters (26 feet) of the equipment or as otherwise approved by the Air Pollution Control Officer

These permits are being issued covering your application on file at the Air Quality Management District.

Very truly yours,

Eric E. Lemke
Chief Deputy Executive Officer

EEL:HT:la
Encs.

Helen Thompson, Permit Section

Rev. 8/78 30D170

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
METROPOLITAN ZONE

ENGINEERING DIVISION - APPLICATION EMISSION DATA SHEET

☑ P/C ☑ Basic Including Spray Booths ☐ Trade-offs DATE: 7/10/78
☑ Rule Reduction

☐ P/O ☐ Control Except Spray Booths ☐ Recall APPL. NO.: C-18850

NAME: SHELL OIL COMPANY

ADDRESS: 1622 EAST SEPULVEDA BLVD., CARSON 90749

☑ Rule 213 Applicable (unit installed or permit to construct issued on or subsequent to 10/8/76).

☐ Rule 213 Not Applicable (unit installed or permit to construct issued prior to 10/8/76, or previously exempt by Rule 219).

Emissions From This Permit Unit

(Complete for basic equipment and spray booths only)

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	4.3	—	—	—	—
Lbs/Day	103.7	—	—	—	—

Altered Permit Unit ☑ Yes ☐ No Prior Permit Number or Date Installed Without Permit PRIOR APPL. NO'S: C-03789 (APPD) P/C <10/8/76 C-08256 (Shell)

(Complete for basic equipment and spray booths only)

Emissions from previous permit unit:

Contaminant	THC	NO_x	SO_2	CO	Part.
Lbs/Hr	~~16.6~~	—	—	—	—
Lbs/Day	~~398.4~~	—	—	—	—

Mitigations (on premise reductions) Achieved Concurrent With This Application
(Also complete for control equipment except spray booths)

Appl. No	H/C Total		NO_x		SO_2		CO		Part.	
	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day	#/Hr	#/Day

BACT Evaluation Not Made ☑ Made ☐ in Appl.________ Date________

Stationary Source (Entire Facility) Employs BACT Yes ☐ No ☐ UNKNOWN

Engineer [signature]

332-60D792-R1

ATTACHMENT D

Rule 1401 Analysis

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2640
Fac:	171107

Stack Data		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	64	feet
Area (For Volume Source Only)	53100	ft^2
Distance-Residential	750	meters
Distance-Commercial	175	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible] output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	6.77E-03	78.11	0.006767331		0.006767331
P15	Chrysene	1.03E-05	228.2928	1.02768E-05		1.02768E-05
C30	Cresol mixtures	3.43E-06	108.14	3.42801E-06		3.42801E-06
E4	Ethyl benzene	1.04E-03	106.16	0.00103808		0.00103808
H8	Hexane (n-)	8.61E-02	86.18	0.086118305		0.086118305
P30	Naphthalene	4.66E-04	128.1732	0.000466385		0.000466385
P3	Phenol	1.15E-06	94.11	1.14951E-06		1.14951E-06
T3	Toluene (methyl benzene)	5.27E-03	92.13	0.005272006		0.005272006
X1	Xylenes (isomers and mixtures)	4.91E-03	106.2	0.004914934		0.004914934
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: T2640
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.25	13.3
Commercial	2.6475	80.25

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

D-2

Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	6.77E-03	6.77E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	1.03E-05	1.03E-05	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	3.43E-06	3.43E-06		1	1	1	1.0000	600	
Ethyl benzene	1.04E-03	1.04E-03	8.70E-03	1	1	1	1	2000	
Hexane (n-)	8.61E-02	8.61E-02		1.0000	1.0000	1	1	7000	
Naphthalene	4.66E-04	4.66E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.15E-06	1.15E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	5.27E-03	5.27E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	4.91E-03	4.91E-03		1.0000	1.0000	1	1	700	22000

D-3

Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	6.77E-03	6.77E-03	59.1194023	0.029559701
Chrysene	1.03E-05	1.03E-05	0.08977779	4.48889E-05
Cresol mixtures	3.43E-06	3.43E-06	0.02994713	1.49736E-05
Ethyl benzene	1.04E-03	1.04E-03	9.06866544	0.004534333
Hexane (n-)	8.61E-02	8.61E-02	752.329513	0.376164756
Naphthalene	4.66E-04	4.66E-04	4.07433527	0.002037168
Phenol	1.15E-06	1.15E-06	0.01004211	5.02105E-06
Toluene (methyl benzene)	5.27E-03	5.27E-03	46.0562405	0.02302812
Xylenes (isomers and mixtures)	4.91E-03	4.91E-03	42.936863	0.021468432
D-4				
Total	1.05E-01	1.05E-01	9.14E+02	4.57E-01

Attachment D

A/N: T2640

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.12E-07	4.39E-07
Chrysene	3.74E-09	3.80E-09
Cresol mixtures		
Ethyl benzene	2.83E-09	5.85E-09
Hexane (n-)		
Naphthalene	1.75E-08	3.63E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**2.36E-07**	**4.85E-07**
	PASS	**PASS**

D-5

No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		6.01E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		6.58E-08	Pass	Pass
Developmental - DEV	4.29E-04	1.50E-03	Pass	Pass
Endocrine system - END		5.94E-06	Pass	Pass
Eye	2.94E-05		Pass	Pass
Hematopoietic system - HEM	4.18E-04	1.29E-03	Pass	Pass
Immune system - IMM	4.18E-04		Pass	Pass
Kidney - KID		6.01E-06	Pass	Pass
Nervous system - NS	1.14E-05	1.71E-03	Pass	Pass
Reproductive system - REP	4.29E-04		Pass	Pass
Respiratory system - RES	2.94E-05	8.75E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2640 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

Compound	HIA - Residential									
	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			6.92E-05		6.92E-05	6.92E-05		6.92E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				2.64E-09					2.64E-09	
Toluene (methyl benzene)			1.90E-06	1.90E-06			1.90E-06	1.90E-06	1.90E-06	
Xylenes (isomers and mixtures)				2.97E-06					2.97E-06	
Total			7.11E-05	4.87E-06	6.92E-05	6.92E-05	1.90E-06	7.11E-05	4.87E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			4.18E-04		4.18E-04	4.18E-04		4.18E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				1.59E-08					1.59E-08	
Toluene (methyl benzene)			1.14E-05	1.14E-05			1.14E-05	1.14E-05	1.14E-05	
Xylenes (isomers and mixtures)				1.79E-05					1.79E-05	
Total			4.29E-04	2.94E-05	4.18E-04	4.18E-04	1.14E-05	4.29E-04	2.94E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.22E-04			1.22E-04			1.22E-04			
Chrysene													
Cresol mixtures										6.18E-09			
Ethyl benzene	5.61E-07			5.61E-07	5.61E-07				5.61E-07				
Hexane (n-)										1.33E-05			
Naphthalene												5.60E-05	
Phenol	6.21E-09		6.21E-09						6.21E-09	6.21E-09			
Toluene (methyl benzene)				1.90E-05						1.90E-05		1.90E-05	
Xylenes (isomers and mixtures)										7.59E-06		7.59E-06	
Total	5.67E-07		6.21E-09	1.41E-04	5.61E-07		1.22E-04		5.67E-07	1.62E-04		8.26E-05	

A/N: T2640 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
	HIC - Commercial												
Benzene (including benzene from gasoline)				1.29E-03			1.29E-03			1.29E-03			
Chrysene													
Cresol mixtures										6.54E-08			
Ethyl benzene	5.94E-06			5.94E-06	5.94E-06				5.94E-06				
Hexane (n-)										1.41E-04			
Naphthalene												5.93E-04	
Phenol	6.58E-08		6.58E-08						6.58E-08	6.58E-08			
Toluene (methyl benzene)				2.01E-04						2.01E-04		2.01E-04	
Xylenes (isomers and mixtures)										8.04E-05		8.04E-05	
Total	6.01E-06		6.58E-08	1.50E-03	5.94E-06		1.29E-03		6.01E-06	1.71E-03		8.75E-04	

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2641
Fac:	171107

Stack Data		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	64	feet
Area (For Volume Source Only)	53100	ft^2
Distance-Residential	750	meters
Distance-Commercial	175	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible] output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	6.77E-03	78.11	0.006767331		0.006767331
P15	Chrysene	1.03E-05	228.2928	1.02768E-05		1.02768E-05
C30	Cresol mixtures	3.43E-06	108.14	3.42801E-06		3.42801E-06
E4	Ethyl benzene	1.04E-03	106.16	0.00103808		0.00103808
H8	Hexane (n-)	8.61E-02	86.18	0.086118305		0.086118305
P30	Naphthalene	4.66E-04	128.1732	0.000466385		0.000466385
P3	Phenol	1.15E-06	94.11	1.14951E-06		1.14951E-06
T3	Toluene (methyl benzene)	5.27E-03	92.13	0.005272006		0.005272006
X1	Xylenes (isomers and mixtures)	4.91E-03	106.2	0.004914934		0.004914934
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N:	T2641
Fac:	171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.25	13.3
Commercial	2.6475	80.25

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

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Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	6.77E-03	6.77E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	1.03E-05	1.03E-05	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	3.43E-06	3.43E-06		1	1	1	1.0000	600	
Ethyl benzene	1.04E-03	1.04E-03	8.70E-03	1	1	1	1	2000	
Hexane (n-)	8.61E-02	8.61E-02		1.0000	1.0000	1	1	7000	
Naphthalene	4.66E-04	4.66E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.15E-06	1.15E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	5.27E-03	5.27E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	4.91E-03	4.91E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	6.77E-03	6.77E-03	59.1194023	0.029559701
Chrysene	1.03E-05	1.03E-05	0.08977779	4.48889E-05
Cresol mixtures	3.43E-06	3.43E-06	0.02994713	1.49736E-05
Ethyl benzene	1.04E-03	1.04E-03	9.06866544	0.004534333
Hexane (n-)	8.61E-02	8.61E-02	752.329513	0.376164756
Naphthalene	4.66E-04	4.66E-04	4.07433527	0.002037168
Phenol	1.15E-06	1.15E-06	0.01004211	5.02105E-06
Toluene (methyl benzene)	5.27E-03	5.27E-03	46.0562405	0.02302812
Xylenes (isomers and mixtures)	4.91E-03	4.91E-03	42.936863	0.021468432
Total	1.05E-01	1.05E-01	9.14E+02	4.57E-01

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Attachment D

A/N: T2641

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.12E-07	4.39E-07
Chrysene	3.74E-09	3.80E-09
Cresol mixtures		
Ethyl benzene	2.83E-09	5.85E-09
Hexane (n-)		
Naphthalene	1.75E-08	3.63E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**2.36E-07**	**4.85E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		6.01E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		6.58E-08	Pass	Pass
Developmental - DEV	4.29E-04	1.50E-03	Pass	Pass
Endocrine system - END		5.94E-06	Pass	Pass
Eye	2.94E-05		Pass	Pass
Hematopoietic system - HEM	4.18E-04	1.29E-03	Pass	Pass
Immune system - IMM	4.18E-04		Pass	Pass
Kidney - KID		6.01E-06	Pass	Pass
Nervous system - NS	1.14E-05	1.71E-03	Pass	Pass
Reproductive system - REP	4.29E-04		Pass	Pass
Respiratory system - RES	2.94E-05	8.75E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2641

Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			6.92E-05		6.92E-05	6.92E-05		6.92E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				2.64E-09					2.64E-09	
Toluene (methyl benzene)			1.90E-06	1.90E-06			1.90E-06	1.90E-06	1.90E-06	
Xylenes (isomers and mixtures)				2.97E-06					2.97E-06	
Total			7.11E-05	4.87E-06	6.92E-05	6.92E-05	1.90E-06	7.11E-05	4.87E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			4.18E-04		4.18E-04	4.18E-04		4.18E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				1.59E-08					1.59E-08	
Toluene (methyl benzene)			1.14E-05	1.14E-05			1.14E-05	1.14E-05	1.14E-05	
Xylenes (isomers and mixtures)				1.79E-05					1.79E-05	
Total			4.29E-04	2.94E-05	4.18E-04	4.18E-04	1.14E-05	4.29E-04	2.94E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.22E-04			1.22E-04			1.22E-04			
Chrysene													
Cresol mixtures										6.18E-09			
Ethyl benzene	5.61E-07			5.61E-07	5.61E-07				5.61E-07				
Hexane (n-)										1.33E-05			
Naphthalene												5.60E-05	
Phenol	6.21E-09		6.21E-09						6.21E-09	6.21E-09			
Toluene (methyl benzene)				1.90E-05						1.90E-05		1.90E-05	
Xylenes (isomers and mixtures)										7.59E-06		7.59E-06	
Total	5.67E-07		6.21E-09	1.41E-04	5.61E-07		1.22E-04		5.67E-07	1.62E-04		8.26E-05	

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Attachment D

A/N: T2641 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
	HIC - Commercial												
Benzene (including benzene from gasoline)				1.29E-03			1.29E-03			1.29E-03			
Chrysene													
Cresol mixtures										6.54E-08			
Ethyl benzene	5.94E-06			5.94E-06	5.94E-06				5.94E-06				
Hexane (n-)										1.41E-04			
Naphthalene												5.93E-04	
Phenol	6.58E-08		6.58E-08						6.58E-08	6.58E-08			
Toluene (methyl benzene)				2.01E-04						2.01E-04		2.01E-04	
Xylenes (isomers and mixtures)										8.04E-05		8.04E-05	
Total	6.01E-06		6.58E-08	1.50E-03	5.94E-06		1.29E-03		6.01E-06	1.71E-03		8.75E-04	

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	T2643
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	48	feet
Area (For Volume Source Only)	3000	ft^2
Distance-Residential	700	meters
Distance-Commercial	125	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible] output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	2.03E-03	78.11	0.002032162		0.002032162
P15	Chrysene	2.28E-06	228.2928	2.28401E-06		2.28401E-06
C30	Cresol mixtures	1.08E-09	108.14	1.08408E-09		1.08408E-09
E4	Ethyl benzene	2.17E-04	106.16	0.000216897		0.000216897
H8	Hexane (n-)	2.67E-02	86.18	0.026666731		0.026666731
P30	Naphthalene	8.16E-05	128.1732	8.16228E-05		8.16228E-05
P3	Phenol	2.57E-09	94.11	2.56972E-09		2.56972E-09
T3	Toluene (methyl benzene)	1.21E-03	92.13	0.001209388		0.001209388
X1	Xylenes (isomers and mixtures)	8.45E-04	106.2	0.000844927		0.000844927
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N:	T2643
Fac:	171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.282	16.48
Commercial	4.8075	180

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

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Attachment D

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	2.03E-03	2.03E-03	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	2.28E-06	2.28E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	1.08E-09	1.08E-09		1	1	1	1.0000	600	
Ethyl benzene	2.17E-04	2.17E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	2.67E-02	2.67E-02		1.0000	1.0000	1	1	7000	
Naphthalene	8.16E-05	8.16E-05	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	2.57E-09	2.57E-09		1	1	1	1	200	5800
Toluene (methyl benzene)	1.21E-03	1.21E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	8.45E-04	8.45E-04		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	2.03E-03	2.03E-03	17.7529684	0.008876484
Chrysene	2.28E-06	2.28E-06	0.01995308	9.97654E-06
Cresol mixtures	1.08E-09	1.08E-09	9.4706E-06	4.73528E-09
Ethyl benzene	2.17E-04	2.17E-04	1.89481337	0.000947407
Hexane (n-)	2.67E-02	2.67E-02	232.960559	0.11648028
Naphthalene	8.16E-05	8.16E-05	0.71305648	0.000356528
Phenol	2.57E-09	2.57E-09	2.2449E-05	1.12245E-08
Toluene (methyl benzene)	1.21E-03	1.21E-03	10.5652147	0.005282607
Xylenes (isomers and mixtures)	8.45E-04	8.45E-04	7.38127901	0.00369064
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Total	3.11E-02	3.11E-02	2.71E+02	1.36E-01

Attachment D

A/N: T2643

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	7.18E-08	2.39E-07
Chrysene	9.37E-10	1.53E-09
Cresol mixtures		
Ethyl benzene	6.67E-10	2.22E-09
Hexane (n-)		
Naphthalene	3.46E-09	1.15E-08
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**7.69E-08**	**2.54E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	NO
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		2.25E-06	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		2.67E-10	Pass	Pass
Developmental - DEV	2.87E-04	7.90E-04	Pass	Pass
Endocrine system - END		2.25E-06	Pass	Pass
Eye	1.28E-05		Pass	Pass
Hematopoietic system - HEM	2.81E-04	7.04E-04	Pass	Pass
Immune system - IMM	2.81E-04		Pass	Pass
Kidney - KID		2.25E-06	Pass	Pass
Nervous system - NS	5.88E-06	8.92E-04	Pass	Pass
Reproductive system - REP	2.87E-04		Pass	Pass
Respiratory system - RES	1.28E-05	2.97E-04	Pass	Pass
Skin			Pass	Pass

A/N: T2643 **Application deemed complete date:** 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			2.58E-05		2.58E-05	2.58E-05		2.58E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				7.30E-12					7.30E-12	
Toluene (methyl benzene)			5.39E-07	5.39E-07			5.39E-07	5.39E-07	5.39E-07	
Xylenes (isomers and mixtures)				6.33E-07					6.33E-07	
Total			2.63E-05	1.17E-06	2.58E-05	2.58E-05	5.39E-07	2.63E-05	1.17E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			2.81E-04		2.81E-04	2.81E-04		2.81E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				7.97E-11					7.97E-11	
Toluene (methyl benzene)			5.88E-06	5.88E-06			5.88E-06	5.88E-06	5.88E-06	
Xylenes (isomers and mixtures)				6.91E-06					6.91E-06	
Total			2.87E-04	1.28E-05	2.81E-04	2.81E-04	5.88E-06	2.87E-04	1.28E-05	

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Attachment D

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				4.13E-05			4.13E-05			4.13E-05			
Chrysene													
Cresol mixtures										2.20E-12			
Ethyl benzene	1.32E-07			1.32E-07	1.32E-07				1.32E-07				
Hexane (n-)										4.65E-06			
Naphthalene												1.11E-05	
Phenol	1.57E-11		1.57E-11						1.57E-11	1.57E-11			
Toluene (methyl benzene)				4.92E-06						4.92E-06		4.92E-06	
Xylenes (isomers and mixtures)										1.47E-06		1.47E-06	
Total	1.32E-07		1.57E-11	4.64E-05	1.32E-07		4.13E-05		1.32E-07	5.23E-05		1.74E-05	

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Attachment D

A/N: T2643 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

Compound	HIC - Commercial												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				7.04E-04			7.04E-04			7.04E-04			
Chrysene													
Cresol mixtures										3.76E-11			
Ethyl benzene	2.25E-06			2.25E-06	2.25E-06				2.25E-06				
Hexane (n-)										7.92E-05			
Naphthalene												1.89E-04	
Phenol	2.67E-10		2.67E-10						2.67E-10	2.67E-10			
Toluene (methyl benzene)				8.38E-05						8.38E-05		8.38E-05	
Xylenes (isomers and mixtures)										2.51E-05		2.51E-05	
Total	2.25E-06		2.67E-10	7.90E-04	2.25E-06		7.04E-04		2.25E-06	8.92E-04		2.97E-04	

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	R510
Fac:	171107

Stack Data

		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	650	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible] output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0 1	lbs/hr
B1	Benzene (including benzene from gasoline)	7.83E-04	78.11	0.000783105		0.000783105
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.84E-04	106.16	0.000584475		0.000584475
H8	Hexane (n-)	5.46E-03	86.18	0.005458904		0.005458904
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.42E-03	92.13	0.002420091		0.002420091
X1	Xylenes (isomers and mixtures)	3.68E-03	106.2	0.003675799		0.003675799
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R510
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors table:

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.302	15.7
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	7.83E-04	7.83E-04	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.84E-04	5.84E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	5.46E-03	5.46E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.42E-03	2.42E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.68E-03	3.68E-03		1.0000	1.0000	1	1	700	22000

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4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	7.83E-04	7.83E-04	6.84120548	0.003420603
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.84E-04	5.84E-04	5.1059726	0.002552986
Hexane (n-)	5.46E-03	5.46E-03	47.6889863	0.023844493
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.42E-03	2.42E-03	21.1419178	0.010570959
Xylenes (isomers and mixtures)	3.68E-03	3.68E-03	32.1117808	0.01605589
Total	1.33E-02	1.33E-02	1.16E+02	5.80E-02

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Attachment D

A/N: R510

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	2.96E-08	2.50E-07
Chrysene	3.51E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	1.93E-09	1.62E-08
Hexane (n-)		
Naphthalene	1.57E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**5.08E-08**	**4.14E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	**NO**
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL
HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.68E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.43E-04	1.21E-03	Pass	Pass
Endocrine system - END		1.65E-05	Pass	Pass
Eye	4.97E-05		Pass	Pass
Hematopoietic system - HEM	1.29E-04	7.37E-04	Pass	Pass
Immune system - IMM	1.29E-04		Pass	Pass
Kidney - KID		1.68E-05	Pass	Pass
Nervous system - NS	1.40E-05	1.53E-03	Pass	Pass
Reproductive system - REP	1.43E-04		Pass	Pass
Respiratory system - RES	4.97E-05	2.92E-03	Pass	Pass
Skin			Pass	Pass

A/N: R510 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

Compound	HIA - Residential									
	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			9.46E-06		9.46E-06	9.46E-06		9.46E-06		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.09E-09					3.09E-09	
Toluene (methyl benzene)			1.03E-06	1.03E-06			1.03E-06	1.03E-06	1.03E-06	
Xylenes (isomers and mixtures)				2.62E-06					2.62E-06	
Total			1.05E-05	3.65E-06	9.46E-06	9.46E-06	1.03E-06	1.05E-05	3.65E-06	

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Attachment D

					HIA - Commercial					
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.29E-04		1.29E-04	1.29E-04		1.29E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.40E-05	1.40E-05			1.40E-05	1.40E-05	1.40E-05	
Xylenes (isomers and mixtures)				3.57E-05					3.57E-05	
Total			1.43E-04	4.97E-05	1.29E-04	1.29E-04	1.40E-05	1.43E-04	4.97E-05	

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Compound	HIC - Residential												
	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				1.70E-05			1.70E-05			1.70E-05			
Chrysene													
Cresol mixtures										4.97E-09			
Ethyl benzene	3.82E-07			3.82E-07	3.82E-07				3.82E-07				
Hexane (n-)										1.02E-06			
Naphthalene												5.02E-05	
Phenol	7.45E-09		7.45E-09						7.45E-09	7.45E-09			
Toluene (methyl benzene)				1.05E-05						1.05E-05		1.05E-05	
Xylenes (isomers and mixtures)										6.86E-06		6.86E-06	
Total	3.89E-07		7.45E-09	2.80E-05	3.82E-07		1.70E-05		3.89E-07	3.55E-05		6.76E-05	

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A/N: R510 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				7.37E-04			7.37E-04			7.37E-04			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.65E-05			1.65E-05	1.65E-05				1.65E-05				
Hexane (n-)										4.40E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.55E-04						4.55E-04		4.55E-04	
Xylenes (isomers and mixtures)										2.96E-04		2.96E-04	
Total	1.68E-05		3.22E-07	1.21E-03	1.65E-05		7.37E-04		1.68E-05	1.53E-03		2.92E-03	

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Attachment D

TIER 1 / TIER 2 SCREENING RISK ASSESSMENT DATA INPUT

Application deemed complete date:	09/10/10
A/N:	R511
Fac:	171107

Stack Data		Units
Hour/Day	24	hr/day
Day/Week	7	day/wk
Week/Year	52	wk/yr
Emission Units	lb/hr	
		0
Control Efficiency	0.00	fraction range 0-1
Does source have TBACT?	YES	
Point or Volume Source ?	V	P or V
Stack Height or Building Height	50	feet
Area (For Volume Source Only)	47742.25	ft^2
Distance-Residential	550	meters
Distance-Commercial	50	meters
Meteorological Station	Long Beach	

Source Type:	O - Other
Screening Mode (**NO** = Tier 1 or Tier 2; **YES** = Tier 3)	NO

Emission Units	lb/hr	
S[illegible] output capacity	n/a	n/a

FOR OTHER SOURCE TYPES DIFFERENT THAN BOILER, CREMATORY OR ICE, FILL IN THE TABLE BELOW

USER DEFINED CHEMICALS AND EMISSIONS				R1 - Uncontrolled	Efficiency Factor	R2 - Controlled
Cmpound Code	Compound	lb/hr	Molecular Weight	lbs/hr	Fraction range 0-1	lbs/hr
B1	Benzene (including benzene from gasoline)	7.83E-04	78.11	0.000783105		0.000783105
P15	Chrysene	7.99E-06	228.2928	7.99087E-06		7.99087E-06
C30	Cresol mixtures	2.28E-06	108.14	2.28311E-06		2.28311E-06
E4	Ethyl benzene	5.84E-04	106.16	0.000584475		0.000584475
H8	Hexane (n-)	5.46E-03	86.18	0.005458904		0.005458904
P30	Naphthalene	3.46E-04	128.1732	0.00034589		0.00034589
P3	Phenol	1.14E-06	94.11	1.14155E-06		1.14155E-06
T3	Toluene (methyl benzene)	2.42E-03	92.13	0.002420091		0.002420091
X1	Xylenes (isomers and mixtures)	3.68E-03	106.2	0.003675799		0.003675799
				0		
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TIER 2 SCREENING RISK ASSESSMENT REPORT

A/N: R511
Fac: 171107

Application deemed complete date: 09/10/10

2. Tier 2 Data

MET Factor	0.99
4 hr	0.92
6 or 7 hrs	0.87

Dispersion Factors tables

5	For Chronic X/Q
7	For Acute X/Q

Dilution Factors (ug/m3)/(tons/yr)

Receptor	X/Q	X/Qmax
Residential	0.354	18.1
Commercial	13.05	213.8

Adjustment and Intake Factors

	AFann	DBR	EVF
Residential	1	302	0.96
Worker	1	149	0.38

3. Rule 1401 Compound Data

Compound	R1 - uncontrolled (lbs/hr)	R2 - controlled (lbs/hr)	CP	MP MICR Resident	MP MICR Worker	MP Chronic Resident	MP Chronic Worker	REL Chronic	REL Acute
Benzene (including benzene from gasoline)	7.83E-04	7.83E-04	1.00E-01	1.0000	1.0000	1.0000	1.0000	60	1300
Chrysene	7.99E-06	7.99E-06	3.90E-02	29.75970425	14.62107209	1	1		
Cresol mixtures	2.28E-06	2.28E-06		1	1	1	1.0000	600	
Ethyl benzene	5.84E-04	5.84E-04	8.70E-03	1	1	1	1	2000	
Hexane (n-)	5.46E-03	5.46E-03		1.0000	1.0000	1	1	7000	
Naphthalene	3.46E-04	3.46E-04	1.20E-01	1.0000	1.0000	1	1	9	
Phenol	1.14E-06	1.14E-06		1	1	1	1	200	5800
Toluene (methyl benzene)	2.42E-03	2.42E-03		1	1	1	1	300	37000
Xylenes (isomers and mixtures)	3.68E-03	3.68E-03		1.0000	1.0000	1	1	700	22000

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Attachment D

4. Emission Calculations

Compound	uncontrolled R1 (lb/hr)	controlled R2 (lb/hr)	R2 (lb/yr)	R2 (ton/yr)
Benzene (including benzene from gasoline)	7.83E-04	7.83E-04	6.84120548	0.003420603
Chrysene	7.99E-06	7.99E-06	0.06980822	3.49041E-05
Cresol mixtures	2.28E-06	2.28E-06	0.01994521	9.9726E-06
Ethyl benzene	5.84E-04	5.84E-04	5.1059726	0.002552986
Hexane (n-)	5.46E-03	5.46E-03	47.6889863	0.023844493
Naphthalene	3.46E-04	3.46E-04	3.02169863	0.001510849
Phenol	1.14E-06	1.14E-06	0.0099726	4.9863E-06
Toluene (methyl benzene)	2.42E-03	2.42E-03	21.1419178	0.010570959
Xylenes (isomers and mixtures)	3.68E-03	3.68E-03	32.1117808	0.01605589
Total	1.33E-02	1.33E-02	1.16E+02	5.80E-02

A/N: R511

Application deemed complete date: 09/10/10

TIER 2 RESULTS

5a. MICR

MICR = CP (mg/(kg-day))^-1 * Q (ton/yr) * (X/Q) * AFann * MET * DBR * EVF * 1E-6* MP

Compound	Residential	Commercial
Benzene (including benzene from gasoline)	3.48E-08	2.50E-07
Chrysene	4.12E-09	1.46E-08
Cresol mixtures		
Ethyl benzene	2.26E-09	1.62E-08
Hexane (n-)		
Naphthalene	1.84E-08	1.33E-07
Phenol		
Toluene (methyl benzene)		
Xylenes (isomers and mixtures)		
Total	**5.95E-08**	**4.14E-07**
	PASS	**PASS**

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No Cancer Burden, MICR<1.0E-6

5b. Cancer Burden	NO
X/Q for one-in-a-million:	
Distance (meter)	
Area (km2):	
Population:	-
Cancer Burden:	

Attachment D

6. Hazard Index

HIA = [Q(lb/hr) * (X/Q)max] * AF / Acute REL

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

Target Organs	Acute	Chronic	Acute Pass/Fail	Chronic Pass/Fail
Alimentary system (liver) - AL		1.68E-05	Pass	Pass
Bones and teeth - BN			Pass	Pass
Cardiovascular system - CV		3.22E-07	Pass	Pass
Developmental - DEV	1.43E-04	1.21E-03	Pass	Pass
Endocrine system - END		1.65E-05	Pass	Pass
Eye	4.97E-05		Pass	Pass
Hematopoietic system - HEM	1.29E-04	7.37E-04	Pass	Pass
Immune system - IMM	1.29E-04		Pass	Pass
Kidney - KID		1.68E-05	Pass	Pass
Nervous system - NS	1.40E-05	1.53E-03	Pass	Pass
Reproductive system - REP	1.43E-04		Pass	Pass
Respiratory system - RES	4.97E-05	2.92E-03	Pass	Pass
Skin			Pass	Pass

A/N: R511 Application deemed complete date: 09/10/10

6a. Hazard Index Acute

HIA = [Q(lb/hr) * (X/Q)max] *AF/ Acute REL

	HIA - Residential									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.09E-05		1.09E-05	1.09E-05		1.09E-05		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				3.56E-09					3.56E-09	
Toluene (methyl benzene)			1.18E-06	1.18E-06			1.18E-06	1.18E-06	1.18E-06	
Xylenes (isomers and mixtures)				3.02E-06					3.02E-06	
Total			1.21E-05	4.21E-06	1.09E-05	1.09E-05	1.18E-06	1.21E-05	4.21E-06	

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Attachment D

	HIA - Commercial									
Compound	AL	CV	DEV	EYE	HEM	IMM	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)			1.29E-04		1.29E-04	1.29E-04		1.29E-04		
Chrysene										
Cresol mixtures										
Ethyl benzene										
Hexane (n-)										
Naphthalene										
Phenol				4.21E-08					4.21E-08	
Toluene (methyl benzene)			1.40E-05	1.40E-05			1.40E-05	1.40E-05	1.40E-05	
Xylenes (isomers and mixtures)				3.57E-05					3.57E-05	
Total			1.43E-04	4.97E-05	1.29E-04	1.29E-04	1.40E-05	1.43E-04	4.97E-05	

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Attachment D

6b. Hazard Index Chronic

HIC = [Q(ton/yr) * (X/Q) * MET * MP] / Chronic REL

	HIC - Residential												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				2.00E-05			2.00E-05			2.00E-05			
Chrysene													
Cresol mixtures										5.82E-09			
Ethyl benzene	4.47E-07			4.47E-07	4.47E-07				4.47E-07				
Hexane (n-)										1.19E-06			
Naphthalene												5.88E-05	
Phenol	8.74E-09		8.74E-09						8.74E-09	8.74E-09			
Toluene (methyl benzene)				1.23E-05						1.23E-05		1.23E-05	
Xylenes (isomers and mixtures)										8.04E-06		8.04E-06	
Total	4.56E-07		8.74E-09	3.28E-05	4.47E-07		2.00E-05		4.56E-07	4.16E-05		7.92E-05	

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Attachment D

A/N: R511 Application deemed complete date: 09/10/10

6b. Hazard Index Chronic (cont.)

	HIC - Commercial												
Compound	AL	BN	CV	DEV	END	EYE	HEM	IMM	KID	NS	REP	RESP	SKIN
Benzene (including benzene from gasoline)				7.37E-04			7.37E-04			7.37E-04			
Chrysene													
Cresol mixtures										2.15E-07			
Ethyl benzene	1.65E-05			1.65E-05	1.65E-05				1.65E-05				
Hexane (n-)										4.40E-05			
Naphthalene												2.17E-03	
Phenol	3.22E-07		3.22E-07						3.22E-07	3.22E-07			
Toluene (methyl benzene)				4.55E-04						4.55E-04		4.55E-04	
Xylenes (isomers and mixtures)										2.96E-04		2.96E-04	
Total	1.68E-05		3.22E-07	1.21E-03	1.65E-05		7.37E-04		1.68E-05	1.53E-03		2.92E-03	

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Attachment D

South Coast Air Quality Management District

Form 400 - XPP

Express Permit Processing Request

Form 400-A, Form 400-CEQA and one or more 400-E-xx form(s) must accompany all submittals.

Mail To:
SCAQMD
P.O Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator To Appear On The Permit):
Phillips 66 Los Angeles Refinery, Carson Plant

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD):
171109

Section B - Equipment Location Address

3. (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

1520 East Sepulveda Boulevard
Street Address

Carson, CA 90745
City, State, Zip

Knut Beruldsen — Env. Engineer
Contact Name — Title

(310) 952-6504
Phone # — Ext. — Fax #

knut.j.beruldsen@p66.com
E-Mail

Section C - Permit Mailing Address

4. Permit and Correspondence Information:
☐ Check here if same as equipment location address

1660 West Anaheim Street
Address

Wilmington, CA 90744
City, State, Zip

Knut Beruldsen — Env. Engineer
Contact Name — Title

(310) 952-6504
Phone # — Ext. — Fax #

knut.j.beruldsen@p66.com
E-Mail

Section D - Authorization/Signature

I understand that the Expedited Permit Processing fees must be submitted at the time of application submittal, and that the application may be subject to additional fees per Rule 301. I understand that requests for Express Permit Processing neither guarantees action by any specific date nor does it guarantee permit approval; that Express Permit Processing is subject to availability of qualified staff; and that once Express Permit Processing has commenced, the expedited fees will not be refunded. I hereby certify that all information contained herein and information submitted with the application are true and correct.

5. Signature of Responsible Official: [signature]	6. Title of Responsible Official: Env. Superintendent
7. Print Name of Responsible Official: Marshall Waller	8. Date: 10/25/12
9. Phone #: (310) 952-6120	10. Fax #:

AQMD USE ONLY	APPLICATION TRACKING #		TYPE B C	EQUIPMENT CATEGORY CODE:	FEE SCHEDULE: $		VALIDATION
ENG. DATE A R	ENG. DATE A R		CLASS I III	ASSIGNMENT Unit Engineer	CHECK/MONEY ORDER #	AMOUNT $	TRACKING #

South Coast Air Quality Management District
Form 400-CEQA
California Environmental Quality Act (CEQA) Applicability

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

The SCAQMD is required by state law, the California Environmental Quality Act (CEQA), to review discretionary permit project applications for potential air quality and other environmental impacts. This form is a screening tool to assist the SCAQMD in clarifying whether or not the project[1] has the potential to generate significant adverse environmental impacts that might require preparation of a CEQA document [CEQA Guidelines §15060(a)].[2] Refer to the attached instructions for guidance in completing this form.[3] For each Form 400-A application, also complete and submit one Form 400-CEQA. If submitting multiple Form 400-A applications for the same project at the same time, only one 400-CEQA form is necessary for the entire project. If you need assistance completing this form, contact Permit Services at (909) 396-3385 or (909) 396-2668.

Section A - Facility Information

1. Facility Name (Business Name of Operator To Appear On The Permit): Phillips 66 Los Angeles Refinery, Carson Plant

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

3. Project Description:
Installation of two 575K BBL crude oil storage tanks, modification of 2 existing crude tanks, and installation of a 11.5K BBL water draw tank to increase the crude storage capacity of the facility.

Section B - Review For Exemption From Further CEQA Action

Check "Yes" or "No" as applicable

	Yes	No	Is this application for:
1.	⦿	○	**A CEQA and/or NEPA document previously or currently prepared that specifically evaluates this project?** If yes, attach a copy of the signed Notice of Determination to this form.
2.	○	⦿	**A request for a change of permittee only (without equipment modifications)?**
3.	○	⦿	**A functionally identical permit unit replacement with no increase in rating or emissions?**
4.	○	⦿	**A change of daily VOC permit limit to a monthly VOC permit limit?**
5.	○	⦿	**Equipment damaged as a result of a disaster during state of emergency?**
6.	○	⦿	**A Title V** (i.e., Regulation XXX) **permit renewal (without equipment modifications)?**
7.	○	⦿	**A Title V administrative permit revision?**
8.	○	⦿	**The conversion of an existing permit into an initial Title V permit?**

If "**Yes**" is checked for any question in Section B, your application does not require additional evaluation for CEQA applicability. Skip to Section D - Signatures on page 2 and sign and date this form.

Section C - Review of Impacts Which May Trigger CEQA

Complete Parts I-VI by checking "Yes" or "No" as applicable. To avoid delays in processing your application(s), explain all "Yes" responses on a separate sheet and attach it to this form.

	Yes	No	Part I - General
1.	○	○	**Has this project generated any known public controversy regarding potential adverse impacts that may be generated by the project?** Controversy may be construed as concerns raised by local groups at public meetings; adverse media attention such as negative articles in newspapers or other periodical publications, local news programs, environmental justice issues, etc.
2.	○	○	**Is this project part of a larger project?** If yes, attach a separate sheet to briefly describe the larger project.
			Part II - Air Quality
3.	○	○	**Will there be any demolition, excavating, and/or grading construction activities that encompass an area exceeding 20,000 square feet?**
4.	○	○	**Does this project include the open outdoor storage of dry bulk solid materials that could generate dust?** If Yes, include a plot plan with the application package.

[1] A "project" means the whole of an action which has a potential for resulting in physical change to the environment, including construction activities, clearing or grading of land, improvements to existing structures, and activities or equipment involving the issuance of a permit. For example, a project might include installation of a new, or modification of an existing internal combustion engine, dry-cleaning facility, boiler, gas turbine, spray coating booth, solvent cleaning tank, etc.

[2] To download the CEQA guidelines, visit http://ceres.ca.gov/env_law/state.html.

[3] To download this form and the instructions, visit http://www.aqmd.gov/ceqa or http://www.aqmd.gov/permit

Section C - Review of Impacts Which May Trigger CEQA (cont.)			
	Yes	No	Part II - Air Quality (cont.)
5.	○	○	**Would this project result in noticeable off-site odors from activities that may not be subject to SCAQMD permit requirements?** For example, compost materials or other types of greenwaste (i.e., lawn clippings, tree trimmings, etc.) have the potential to generate odor complaints subject to Rule 402 – Nuisance.
6.	○	○	**Does this project cause an increase of emissions from marine vessels, trains and/or airplanes?**
7.	○	○	**Will the proposed project increase the QUANTITY of hazardous materials stored aboveground onsite or transported by mobile vehicle to or from the site by greater than or equal to the amounts associated with each compound on the attached Table 1?[4]**
			Part III – Water Resources
8.	○	○	**Will the project increase demand for water at the facility by more than 5,000,000 gallons per day?** The following examples identify some, but not all, types of projects that may result in a "yes" answer to this question: 1) projects that generate steam; 2) projects that use water as part of the air pollution control equipment; 3) projects that require water as part of the production process; 4) projects that require new or expansion of existing sewage treatment facilities; 5) projects where water demand exceeds the capacity of the local water purveyor to supply sufficient water for the project; and 6) projects that require new or expansion of existing water supply facilities.
9.	○	○	**Will the project require construction of new water conveyance infrastructure?** Examples of such projects are when water demands exceed the capacity of the local water purveyor to supply sufficient water for the project, or require new or modified sewage treatment facilities such that the project requires new water lines, sewage lines, sewage hook-ups, etc.
			Part IV – Transportation/Circulation
10.			**Will the project result in** (Check all that apply):
	○	○	**a. the need for more than 350 new employees?**
	○	○	**b. an increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round-trips per day?**
	○	○	**c. increase customer traffic by more than 700 visits per day?**
			Part V – Noise
11.	○	○	**Will the project include equipment that will generate noise GREATER THAN 90 decibels (dB) at the property line?**
			Part VI – Public Services
12.			**Will the project create a permanent need for new or additional public services in any of the following areas** (Check all that apply):
	○	○	**a. Solid waste disposal?** Check "No" if the projected potential amount of wastes generated by the project is less than five tons per day.
	○	○	**b. Hazardous waste disposal?** Check "No" if the projected potential amount of hazardous wastes generated by the project is less than 42 cubic yards per day (or equivalent in pounds).

REMINDER: *For each "Yes" response in Section C, attach all pertinent information including but not limited to estimated quantities, volumes, weights, etc.*

Section D - Signatures

I HEREBY CERTIFY THAT ALL INFORMATION CONTAINED HEREIN AND INFORMATION SUBMITTED WITH THIS APPLICATION IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE. I UNDERSTAND THAT THIS FORM IS A SCREENING TOOL AND THAT THE SCAQMD RESERVES THE RIGHT TO CONSIDER OTHER PERTINENT INFORMATION IN DETERMINING CEQA APPLICABILITY.

1. Signature of Responsible Official of Firm: M Waller		2. Title of Responsible Official of Firm: Env. Superintendent
3. Print Name of Responsible Official of Firm: Marshall Waller		4. Date Signed: 11/19/12
5. Phone # of Responsible Official of Firm: (310) 952-6120	6. Fax # of Responsible Official of Firm:	7. Email of Responsible Official of Firm: marshall.g.waller@p66.com
8. Signature of Preparer, (If prepared by person other than responsible official of firm): Marcia Bav		9. Title of Preparer: Project Manager
10. Print Name of Preparer: Marcia Baverman		11. Date Signed: 11/15/12
12. Phone # of Preparer: (714) 632-8521	13. Fax # of Preparer: (714) 632-6754	14. Email of Preparer: mbaverman@envaudit.com

THIS CONCLUDES FORM 400-CEQA. INCLUDE THIS FORM AND ANY ATTACHMENTS WITH FORM 400-A.

[4] Table 1 – Regulated Substances List and Threshold Quantities for Accidental Release Prevention can be found in the Instructions for Form 400-CEQA.

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): Phillips 66 Los Angeles Refinery, Carson Plant

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 171109

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 1520 East Sepulveda Boulevard, Carson, CA 90745

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) ( ) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) (●) Domed External Roof Tank (DEFRT)
Identification	Tank Identification Number: 2640 — Tank Contents/Product (include MSDS): Crude Oil with 7.0 RVP

Section B - Tank Information

Tank Characteristics

Shell Diameter (ft.): 260	Shell Length (ft.):	Shell Height (ft.): 64	Turnovers Per Year: 58
Is Tank Heated? ( ) Yes (●) No	Is Tank Underground? ( ) Yes (●) No	Net Throughput (gal/year): 1210MM	Self Support Roof: (●) Yes ( ) No
Number of Columns? 0	Effective Column Diameter: ( ) 9" by 7" Built Up Column - 1.1	( ) 8" Diameter Pipe - 0.7	( ) Unknown - 1
External Shell Condition: (●) Good ( ) Poor	Internal Shell Color: (●) Light Rust ( ) Dense Rust ( ) Gunite Lining	External Shell Color: (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse	( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer
Average Liquid Height (ft.) (Vertical Only): 30	Maximum Liquid Height (ft.) (Vertical Only): 60	Working Volume (gal.) (Vertical Only): 21000000	Actual Volume (gal.) (Vertical Only): 24150000
Paint Condition: (●) Good ( ) Poor	Paint Color/Shade: (●) White/White ( ) Aluminum/Diffuse	( ) Gray/Light ( ) Aluminum/Specular	( ) Gray/Medium ( ) Red/Primer

Roof Characteristics (Floating Roof Tank)

Roof Type: ( ) Pontoon ( ) Double Deck	(●) Dome Roof (Height 55.5 ft.) ( ) Cone Roof (Height ___ ft.)	Roof Fitting Category: ( ) Typical (●) Detail	Roof Height (ft.):
Roof Paint Condition: (●) Good ( ) Poor	Roof Color/Shade: (●) White/White ( ) Aluminum/Diffuse	( ) Gray/Light ( ) Aluminum/Specular	( ) Gray/Medium ( ) Red/Primer

Deck Characteristics (Floating Roof Tank)

Deck Type: (●) Welded ( ) Bolted

Deck Fitting Characteristics: ( ) Typical ( ) Detailed (Complete Deck Seam)

Construction:	Deck Seam Length (ft.):	Deck Seam:
( ) Sheet		( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide
( ) Panel		( ) 5 x 7.5 ft. ( ) 5 x 12 ft.

Tank Construction and Rim-Seal System (Floating Roof Tank)

Tank Construction: (●) Welded ( ) Riveted	Primary Seal: (●) Mechanical Shoe ( ) Liquid Mounted ( ) Vapor Mounted	Secondary Seal: (●) Rim Mounted ( ) None ( ) Shoe Mounted

Breather Vent Setting

Vacuum Setting (psig): ______ Pressure Setting (psig): ______

* Section D of the application MUST be completed.

South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: Long Beach

Daily Average Ambient Temperature (˚F): 64.31 Annual Average Minimum Temperature (˚F): 54.40

Annual Average Maximum Temperature (˚F): 74.22 Average Wind Speed (mph): 6.36

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): 1571.65

Tank Contents

Chemical Category: ○ Organic Liquids ◉ Crude Oil ○ Petroleum Distillates

Liquid: ○ Single ◉ Multiple

If Multiple, Select Speciation Option: ○ Full Speciation ◉ Partial Speciation ○ Various Weight Speciation ○ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☐ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number:________

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure				☐	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
Crude Oil

If material is stored in a solution, supply the following information:

Name of Solvent:________ Name of Materials Dissolved:________

Concentration of Materials Dissolved:________ % by Weight **OR** ________ % by Volume **OR** ________ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
________ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - __6__ Bolted Cover, Gasketed
   - ________ Unbolted Cover, UnGasketed
   - ________ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - __3__ Bolted Cover, Gasketed
   - ________ Unbolted Cover, Ungasketed
   - ________ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ________ Built-Up Col - Sliding Cover, Gasketed
   - ________ Built-Up Col - Sliding Cover, Ungasketed
   - ________ Pipe Col - Flex, Fabric Sleeve Seal
   - ________ Pipe Col - Sliding Cover, Gasketed
   - ________ Pipe Col - Sliding Cover, Ungasketed

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- 1 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- ____ Sliding Cover, Gasketed
- ____ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ____ Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ____ Open
- ____ 90% Close

8. Roof Leg (3" diameter leg)
- ____ Adjustable, Pontoon Area, Ungasketed
- ____ Adjustable, Center Area, Ungasketed
- 260 Adjustable, Double-Deck Roofs
- ____ Fixed
- ____ Adjustable, Pontoon Area, Gasketed
- ____ Adjustable, Pontoon Area, Sock
- ____ Adjustable, Center Area, Gasketed
- ____ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ____ Adjustable
- ____ Fixed

10. Sample Pipe (24" diameter)
- ____ Slotted Pipe – Sliding Cover, Gasketed
- ____ Slotted Pipe – Sliding Cover, Ungasketed
- ____ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
- ____ Ungasketed, Sliding Cover, Without Float
- ____ Ungasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, Without Float
- ____ Gasketed Sliding Cover, With Float
- ____ Gasketed Sliding Cover, With Pole Sleeve
- ____ Gasketed Sliding Cover, With Pole Wiper
- ____ Gasketed Sliding Cover, With Float, Wiper
- ____ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ____ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well
- ____ Ungasketed, Sliding Cover
- ____ Gasketed Sliding Cover
- ____ Ungasketed Sliding Cover with Sleeve
- ____ Gasketed Sliding Cover with Sleeve
- 1 Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- 6 Weighted Mechanical Actuation, Gasketed
- ____ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: Marcia Baverman	Date: 11/15/12	Name: Marcia Baverman
	Title: Project Manager	Company Name: Environmental Audit Inc.	Phone #: (714) 632-8521 Fax #: (714) 632-6754
			Email: mbaverman@envaudit.com
Contact Info	Name: Knut Beruldsen		Phone #: (310) 952-6504 Fax #:
	Title: Env. Engineer	Company Name: Philips 66	Email: knut.j.beruldsen@p66.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

UPS CampusShip: View/Print Label

1. **Ensure there are no other shipping or tracking labels attached to your package.** Select the Print button on the print dialog box that appears. Note: If your browser does not support this function select Print from the File menu to print the label.

2. **Fold the printed sheet containing the label at the line so that the entire shipping label is visible. Place the label on a single side of the package and cover it completely with clear plastic shipping tape. Do not cover any seams or closures on the package with the label.** Place the label in a UPS Shipping Pouch. If you do not have a pouch, affix the folded label using clear plastic shipping tape over the entire label.

3. **GETTING YOUR SHIPMENT TO UPS**
   UPS locations include the UPS Store®, UPS drop boxes, UPS customer centers, authorized retail outlets and UPS drivers.
   Find your closest UPS location at: www.ups.com/dropoff
   Take your package to any location of The UPS Store®, UPS Drop Box, UPS Customer Center, UPS Alliances (Office Depot® or Staples®) or Authorized Shipping Outlet near you. Items sent via UPS Return Services(SM) (including via Ground) are also accepted at Drop Boxes. To find the location nearest you, please visit the Resources area of CampusShip and select UPS Locations.

   Customers with a Daily Pickup
   Your driver will pickup your shipment(s) as usual.

FOLD HERE

KNUT BERULDSEN
310-952-6504
WILMINGTON, CA - ENVIRONMENTAL
1660 W. ANAHEIM STREET
WILMINGTON CA 90744

0.0 LBS LTR 1 OF 1

SHIP TO:
PERMIT SERVICES
SOUTH COAST AQMD
21865 COPLEY DRIVE
P.O. BOX 4944
DIAMOND BAR CA 91765-4178

CA 916 9-08

UPS NEXT DAY AIR 1

TRACKING #: 1Z V21 4F5 01 9010 5868

BILLING: P/P

Reference #1: ZD0767
Reference #2: ZD0767

ZD0767

Phillips 66
Los Angeles Refinery - Carson Plant
1520 E. Sepulveda Blvd.
Carson, California 90745
P. O. Box 6206
Carson, California 90747
Telephone 310-522-9300
www.phillips66.com

CERTIFIED MAIL RETURN RECEIPT REQUESTED

November 21, 2012

South Coast Air Quality Management District
Attn: Permit Services
P.O. Box 4944
Diamond Bar, CA 91765

NEW CRUDE OIL STORAGE TANKS 2640 & 2641, MODIFIED CRUDE OIL STORAGE TANKS 510 & 511, AND NEW WATER DRAW STORAGE TANK 2643
APPLICATION FOR SIGNIFICANT REVISION OF TITLE V PERMIT
LOS ANGELES REFINERY – CARSON PLANT (ID #171109)

Phillips 66 Company submits the enclosed applications for a "significant permit revision" to the Los Angeles Refinery – Carson Plant Title V permit. The applications are for two new domed external floating roof tanks for crude oil storage, the addition of domes to existing external floating roof tanks 510 and 511, and one new domed external floating roof tank for water draws from the above tanks. The purpose of the project is to increase the storage capacity of crude so that larger ships can unload their entire volume in one call. There will not be an increase in the crude oil processing rate at the refinery as a result of this project. Based on information and belief formed after reasonable inquiry, the statements and information in the enclosed documents has been determined to be true, accurate, and complete.

The information contained in this permit package is considered confidential business information. If there are any questions, please contact Knut J. Beruldsen at (310) 952-6504.

Sincerely,

Chris R. Chandler
Manager, Los Angeles Refinery

Attachments

Ecc: Ms. Janice West, AQMD (w/ attachments)
Submitted via e-mail to: jwest@aqmd.gov

E120470

TITLE V PERMIT APPLICATION
Phillips 66 Company
Los Angeles Refinery Carson Plant
CRUDE OIL STORAGE PROJECT
CONFIDENTIAL

SUMMARY

Phillips 66 Company submits the enclosed applications for a "significant permit revision" to the Los Angeles Refinery – Carson Plant Title V permit.

The application package includes the following:

1) Form 500-A2 Title V Application Certification
2) Form C1 Title V Compliance Status Report
3) Form 400-XPP Express Permit Processing Request
4) Form 400-A (5 total) Permit Application Forms for Tank Nos. 2640, 2641, 2643, 510 and 511
5) Form 400-A for Title V Amendment
6) Form 400-CEQA
7) Form 400-E-18 (5 total) Storage Tank Information
8) Form 400-E-GI Supplemental Information Package
9) Company Check Nos. 00010110, 00010109, 00010107, 00010106, 00010105, and 00010108 for $5,160.09, $2580.05, $5,160.09, $2580.05, $5,160.09 and $1,789.12, respectively, for the permit revision

This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912C	SY	1200000451 USD	5,160.09	0.00	5,160.09

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010105	5160.09

If you have questions about this check, call (918)977-7909
or logon to https://vis.ephillips66.com.

Phillips 66 is currently adopting direct deposit (ACH) as our primary tool for payment in place of checks. Please access the following website http://vendors.phillips66.com/EN/payment/Pages/index.aspx for application instructions. Your prompt response is greatly appreciated.

THIS PORTION IS NON-NEGOTIABLE

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This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912B	SY	1200000452 USD	2,580.05	0.00	2,580.05

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010106	2580.05

If you have questions about this check, call (918)977-7909
or logon to https://vis.ephillips66.com.

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This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912A	SY	1200000453 USD	5,160.09	0.00	5,160.09

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010107	5160.09

If you have questions about this check, call (918)977-7909
or logon to https://vis.ephillips66.com.

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This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912F	SY	1200000454 USD	1,789.12	0.00	1,789.12

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010108	1789.12

If you have questions about this check, call (918)977-7909 or logon to https://vis.ephillips66.com.

Phillips 66 is currently adopting direct deposit (ACH) as our primary tool for payment in place of checks. Please access the following website http://vendors.phillips66.com/EN/payment/Pages/index.aspx for application instructions. Your prompt response is greatly appreciated.

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This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912D	SY	1200000455 USD	2,580.05	0.00	2,580.05

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010109	2580.05

If you have questions about this check, call (918)977-7909 or logon to https://vis.ephillips66.com.

Phillips 66 is currently adopting direct deposit (ACH) as our primary tool for payment in place of checks. Please access the following website http://vendors.phillips66.com/EN/payment/Pages/index.aspx for application instructions. Your prompt response is greatly appreciated.

THIS PORTION IS NON-NEGOTIABLE

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This check was issued by PHILLIPS 66 COMPANY

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.	GROSS	DISCOUNT	NET
10/18/12	101912E	SY	1200000456 USD	5,160.09	0.00	5,160.09

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
119215	10/22/2012	00010110	5160.09

If you have questions about this check, call (918)977-7909
or logon to https://vis.ephillips66.com.

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THIS PORTION IS NON-NEGOTIABLE

THIS PORTION IS NON-NEGOTIABLE

January 31, 2014

Councilman Buscaino
c/o Jenny Chavez, Chief of Staff,
City of Los Angeles jenny.chavez@lacity.org

Dr. Wallerstein, SCAQMD
bwallerstein@aqmd.gov

Re: Follow-up investigation issues for SCAQMD white paper on tar sands-by-rail to Los Angeles

Dear Councilman Buscaino and Dr. Wallerstein,

Thank you very much for meeting with the California Nurses Association (CNA), Tar Sands Action – Southern California, Communities for a Better Environment (CBE), and other concerned community members on January 9, 2014 regarding proposed tar sands-by-rail projects to South Coast oil refineries. This letter is to follow up on specific issues we request to be evaluated in the tar sands white paper that you offered to produce.

To memorialize some of what has happened so far, on April 2, 2013, CBE and the Natural Resources Defense Council (NRDC) sent a letter to the South Coast Air Quality Management District ("District" or "SCAQMD") requesting an investigation of tar sands-by-rail projects announced by Valero and other refineries (attached). The Los Angeles Times covered this.[1] At the SCAQMD April 5th Governing Board meeting that same week, other community members also asked the Board of Directors to investigate tar sands.[2] In response, Dr. Wallerstein stated the following to the Governing Board members, according to the Board minutes:

> *Dr. Wallerstein noted that staff has begun to investigate the tar sand oil issue and will be performing source testing. Once a preliminary evaluation is complete, it will be presented to the Refinery Committee.*

We are looking forward to the South Coast Air Quality Management District (SCAQMD) completing this more detailed investigation and source testing of tar sands crude-by-rail to Los Angeles. (We list below some of the crucial issues this investigation must address.)

CBE also submitted a public records request for the application details of the Valero project last year but received very little information, because Valero argued that the application information was confidential business information. Most recently, we have heard from the District that Valero's proposed Wilmington rail project application[3] is apparently on hold, while Valero's related rail project in Benicia,

---

[1] *Groups seek probe into low-grade crude shipments to L.A. refineries,* Louis Sahagan, LA Times, April 2, 2013, http://articles.latimes.com/2013/apr/02/local/la-me-0403-dirty-oil-20130403 .

[2] Testimony of Al Sattler and Jesse Marquez, Minutes, SCAQMD April 5th Board meeting, p. 18, http://www.aqmd.gov/hb/attachments/2011-2015/2013May/2013-May3-001.pdf

[3] Reuters Market News: June 5, 2013 – *"Valero Energy Corp plans to build a rail offloading facility that could take up to 60,000 barrels per day of cheap North American crude to replace pricey imports at its Los Angeles-area refinery, the*

Northern California, is undergoing review by the Bay Area air Quality Management District (BAAQMD), and the EIR for Valero's Benicia project in Northern California is scheduled to be released soon.[4] We would like to see some progress in investigating environmental, public and worker health and safety issues before Valero moves forward again.

Another project submitted by Phillips 66 has already undergone a first round of comments in response to a Negative Declaration published under California Environmental Quality Act (CEQA). CBE, along with Earth Justice, submitted comments (also attached) calling for a full Environmental Impact Report (EIR) on this project because of the significant environmental and public health impacts that the project has the potential to cause. While our comments documented that Phillips 66 has publicly acknowledged its plans to bring Canadian tar sands and North Dakota Bakken crude oil (a form of crude feedstock that raises its own set of environmental and safety concerns) into California by rail and ship, and specifically to the Los Angeles refinery, the negative declaration failed to mention that the proposed storage and crude unit modifications are needed to allow the processing of tar sands and Bakken crudes. Not only has Phillips 66 acknowledged in annual reports that it plans to bring these crudes to California refineries, but its corporate leaders have also stated plans to <u>export</u> refinery products to China, India, and Brazil.[5] This would mean that local Southern California communities would not only bear the impacts of gas and diesel production that would be used by Californians, but they would also bear the impacts from the added production for export (see our Phillips 66 comments).

We ask that the District exercise its authority to stop this trend in declining crude oil quality, in order to protect Californians, and specifically residents of the South Coast Air Basin, from the potentially devastating impacts of dangerous rail transport,[6] and related emissions increases, before it goes any further.

The District, of course, has the authority under California Health and Safety code to protect the public from potential harms to their health, and damage to property. See, Cal. Health and Safety Code § 40001(b) (District rules and regulations may provide for the prevention and abatement of air pollution causing discomfort or health risks to, or damage to the property of, a significant number of persons or class of persons). Indeed, the District also has a duty to address the increased risks of leaks, fires, and explosions at refineries, which can be caused by tar sands crudes as a result of their high sulfur content, and which can cause significant increases in harmful emissions, disproportionately burdening those communities that surround the refineries that will be receiving, processing and transporting this new feedstock.

California's electric power plants have been required to phase out dirtier fuel oil inputs in favor of natural gas, and are now phasing in renewables in place of natural gas. The authority to require these

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company said on Monday. Valero said it had applied for a building permit from the South Coast Air Quality Management District, the pollution regulator for Los Angeles-area refineries. The agency said it would take about 18 months to finish an environmental review, permitting and construction at the 78,000 bpd refinery in Wilmington, California." . . . "Valero spokesman Bill Day said the company wants to increase rail shipments of North American crude to its California refineries,which is cheaper than foreign imports or Alaskan crude. If approved, the facilities would offload both Canadian heavy and inland U.S. crude. http://www.ubs.wallst.com/ubs/mkt_story.asp?docKey=1329-L1N0EF0T3-1&first=0

[4] http://www.ci.benicia.ca.us/index.asp?SEC={FDE9A332-542E-44C1-BBD0-A94C288675FD}&Type=B_BASIC

[5] Phillips 66, 2012 Summary Annual Report, available at: http://www.phillips66.com/EN/about/reports/Documents/Phillips-66-Summary-Annual-Report.pdf

[6] More oil spilled from trains in 2013 than in previous 4 decades, federal data show, Read more here: http://www.kansascity.com/2014/01/20/4764674/more-oil-spilled-from-trains-in.html#storylink=cpy http://www.kansascity.com/2014/01/20/4764674/more-oil-spilled-from-trains-in.html

feedstock changes is now taken for granted in California. In addition, just last year, the City of Los Angeles agreed to phase out coal feedstocks to its power plants. There has also been regulatory phaseout of other chemical feedstocks at oil refineries, such as anhydrous ammonia and hydrogen fluoride inputs, on the basis of safety.

Sulfur corrosion was in fact, a cause of the major 2012 Northern California Chevron Richmond refinery crude unit explosion according to the U.S. Chemical Safety Board (CSB). That explosion blew a massive toxic plume over the Bay Area, and narrowly missed killing 19 workers.[7]

At the January 9, 2014 meeting, District staff stated that it had inspected local refineries and didn't see corrosion. We would welcome more specific information about any standard protocols performed to identify such corrosion. We assume this was more of a general statement about visual inspection, since this type of sulfur corrosion analysis generally requires taking actual piping samples, such as that performed by the Chemical Safety Board.

In fact, the CSB did find sulfur corrosion in the Southern California Chevron El Segundo refinery's piping by cutting open piping. Further, Steelworkers testified at the CSB hearing April 19, 2013 that refinery sulfur corrosion is a statewide problem. Steelworkers also found California refineries have been steadily reducing maintenance,[8] which was another major factor in the Richmond explosion.

The CSB is now calling for new regulations to increase oil refinery safety in California refineries. The CSB website stated December 16, 2013,[9]

> **In Wake of Chevron 2012 Pipe Rupture and Fire in Bay Area CSB Draft Report Proposes Overhaul of Refinery Industry Regulatory System in California and Urges Adoption of the Safety Case Regime to Prevent Major Chemical Accidents**
>
> There are currently no federal or state regulatory requirements to apply these important preventative measures. The investigation team concluded that enhanced regulatory oversight with greater worker involvement and public participation are needed to improve petroleum refinery safety. . . .
>
> The existing California system of regulation can be significantly improved, the report concludes. Since 2010, the CSB has examined the extent to which a safety case regime would improve regulatory compliance and better prevent major accidents, both onshore and offshore.

Prevention and implementing inherently safer systems, were identified by the CSB as solutions. We need the District to evaluate inherently safer systems. In doing so, the District must examine the potential lives saved and increased safety by preventing a worsening of crude oil feedstock that will

[7] http://www.csb.gov/chevron-refinery-fire/.

[8] Improving Public and Worker Safety at Oil Refineries, Draft Report of the Interagency Working Group on Refinery Safety, Governor Jerry Brown, July 2013, http://www.calepa.ca.gov/Publications/Reports/2013/Refineries.PDF

[9] http://www.csb.gov/in-wake-of-chevron-2012-pipe-rupture-and-fire-in-bay-area-csb-draft-report-proposes-overhaul-of-refinery-industry-regulatory-system-in-california-and-urges-adoption-of-the-safety-case-regime-to-prevent-major-chemical-accidents/

increase the explosion hazard due to sulfur corrosion and hazards due to rail transport. In your white paper, we request that you include the following (although this is not a comprehensive set):

- Reporting of full crude oil slates including both domestic and imported crudes, at Southern California refineries for the last 5 years, including sulfur content, API gravity, and if possible metals content;
- A comparison of these crude oil slates to Canadian tar sands crude oils using crude oil assays including but not limited to sulfur content, API gravity and metals content;
- Evaluation of the risks of processing and transporting Canadian tar sands and Bakken North Dakota crude oils, as identified in our Phillips 66 comments to the District;
- Evaluation of diluents added for transport of tar sands crude;
- Evaluation of the U.S. Chemical Safety Board's recommendations on sulfur corrosion due to crude oil, and recommendations on implementing inherently safer systems, including avoiding the use of dangerous crude oils;
- Compilation of investigations done in the U.S. and Canada regarding increased rail accidents during crude oil transport;
- Identification of rail and pipeline connections to and near Southern California refineries.

The introduction of large volumes of tar sands and Bakken crude oils could endanger Southern California neighborhoods, and would result in an enormous step backward in California's work to fight climate change.

We appreciate the District's time and leadership in addressing the matters in this letter, and we welcome any questions or requests for more information. Please do not hesitate to contact us.

Sincerely,

Jack Eidt, Tar Sands Action, Southern California

Sherry Lear, concerned San Pedro community member

David Monkawa, California Nurses Association (CNA)

Alicia Rivera, Communities for a Better Environment (CBE)

April 2, 2013

Dr. Barry Wallerstein, Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Re: **Increasing Use of Tar Sands at Refineries Within the Region** – Urgent Need For Impacts Assessment

Dear Dr. Wallerstein:

On behalf of NRDC (Natural Resources Defense Council), and its more than 250,000 members in California, and Communities for a Better Environment (CBE), representing thousands of Californians, particularly those located in areas heavily impacted by oil refineries, we are writing to request your urgent action to evaluate the community health, air quality and climate impacts of increasing amounts of tar sands being refined in the region. While refineries in the region are subject to District regulations as well as Title V Clean Air Act permits through your agency, we are concerned that emissions increases may be occurring at refineries processing more dirty crude oils including Canadian tar sands and that these increases have not yet been fully accounted for.

It has come to our attention that oil companies are speeding up and expanding deliveries of one of the world's dirtiest crude oil products to California refineries. For example, Valero President Joe Gordon has publicly stated that the company has allocated rail cars to import what “could be 30,000 barrels a day” of Western Canada Select (WCS) or other diluted bitumen product to its Wilmington plant. This would more than double tar sands deliveries into the Los Angeles area, which were roughly 29,000 barrels for all of 2012 according to the Energy Information Administration. Phillips 66 and Tesoro have also expressed an interest in increasing tar sands shipments into California in recent weeks.

The increasing use of very high sulfur, low-quality crude oils in California refineries presents a major hazard to the surrounding communities that are already facing disproportionately high pollution levels. Refining tar sands will create more local air pollution due to the more intensive processing required for lower quality crude oil, which will lead to increased health consequences for residents near refineries. We also expect increases in carbon pollution, which will make it harder for the state to meet voter-approved targets, if greater quantities of dirtier crude oil sources like tar sands are used in California. Finally, the highly corrosive nature of tar sands will increase the likelihood for spills and accidents, posing direct safety risks and exposure to increased toxic emissions for both plant workers and the surrounding community. Thus, we are calling on the South Coast Air Quality Management District to use all of its regulatory authority to prevent any increase in air pollution due to increased heavy crude utilization by District refineries and conduct a rigorous evaluation of all the health and safety, air quality and climate impacts of increasing use of unconventional, extra heavy crude oils including Canadian tar sands.

We encourage the South Coast Air Quality Management District to be a leader in protecting the health and welfare of its refinery-adjacent residents.

We appreciate your immediate attention to this matter.

Sincerely,

Diane Bailey, Senior Scientist, NRDC

Adrian Martinez, Attorney, NRDC

Alicia Rivera, Wilmington Community Organizer, CBE

Julia May, Senior Scientist CBE

BOARD MEETING DATE: December 5, 2014 AGENDA NO. 21

REPORT: Lead Agency Projects and Environmental Documents Received by the SCAQMD

SYNOPSIS: This report provides, for the Board's consideration, a listing of CEQA documents received by the SCAQMD between October 1, 2014 and October 31, 2014, and those projects for which the SCAQMD is acting as lead agency pursuant to CEQA.

COMMITTEE: Mobile Source, November 21, 2014, Reviewed

RECOMMENDED ACTION:
Receive and file.

Barry R. Wallerstein, D.Env.
Executive Officer

EC:LT:SN:MK:JB:AK

CEQA Document Receipt and Review Logs (Attachments A and B) – Each month, the SCAQMD receives numerous CEQA documents from other public agencies on projects that could adversely affect air quality. A listing of all documents received and reviewed during the reporting period of October 1, 2014, through October 31, 2014 is included in Attachment A. A list of active projects from previous reporting periods for which SCAQMD staff is continuing to evaluate or has prepared comments is included as Attachment B.

The Intergovernmental Review function, which consists of reviewing and commenting on the adequacy of the air quality analysis in CEQA documents prepared by other lead agencies, is consistent with the Governing Board's 1997 Environmental Justice Guiding Principles and Initiative #4. Consistent with the Environmental Justice Program Enhancements for FY 2002-03 approved by the Board in September 2002, each of the attachments notes those proposed projects where the SCAQMD has been contacted regarding potential air quality-related environmental justice concerns. The SCAQMD has established an internal central contact to receive information on projects with potential air quality-related environmental justice concerns. The public may contact the

SCAQMD about projects of concern by the following means: in writing via fax, email, or standard letters; through telephone communication; as part of oral comments at SCAQMD meetings or other meetings where SCAQMD staff is present; or submitting newspaper articles. The attachments also identify for each project the dates of the public comment period and the public hearing date, as reported at the time the CEQA document is received by the SCAQMD. Interested parties should rely on the lead agencies themselves for definitive information regarding public comment periods and hearings as these dates are occasionally modified by the lead agency.

At the January 6, 2006 Board meeting, the Board approved the Workplan for the Chairman's Clean Port Initiatives. One action item of the Chairman's Initiatives was to prepare a monthly report describing CEQA documents for projects related to goods movement and to make full use of the process to ensure the air quality impacts of such projects are thoroughly mitigated. In response to describing goods movement CEQA documents, Attachments A and B are organized to group projects of interest into the following categories: goods movement projects; schools; landfills and wastewater projects; airports; and general land use projects, etc. In response to the mitigation component, guidance information on mitigation measures were compiled into a series of tables relative to: off-road engines; on-road engines; harbor craft; ocean-going vessels; locomotives; fugitive dust; and greenhouse gases. These mitigation measure tables are on the CEQA webpages portion of the SCAQMD's website. Staff will continue compiling tables of mitigation measures for other emission sources including airport ground support equipment, etc.

As resources permit, staff focuses on reviewing and preparing comments for projects: where the SCAQMD is a responsible agency; that may have significant adverse regional air quality impacts (e.g., special event centers, landfills, goods movement, etc.); that may have localized or toxic air quality impacts (e.g., warehouse and distribution centers); where environmental justice concerns have been raised; and those projects for which a lead or responsible agency has specifically requested SCAQMD review. If the SCAQMD staff provided written comments to the lead agency as noted in the column "Comment Status", there is a link to the "SCAQMD Letter" under the Project Description. In addition, if the SCAQMD staff testified at a hearing for the proposed project, a notation is provided under the "Comment Status." If there is no notation that the SCAQMD staff testified, then staff did not provide testimony at a hearing for the proposed project.

During the period October 1, 2014 through October 31, 2014, the SCAQMD received 99 CEQA documents. Of the total of 109 documents listed in Attachments A and B:

- 31 comment letters were sent;
- 11 documents were reviewed, but no comments were made;
- 23 documents are currently under review;
- 3 documents did not require comments (e.g., public notices, plot plans, Final Environmental Impact Reports);
- 1 documents were not reviewed; and
- 40 were screened without additional review.

Copies of all comment letters sent to lead agencies can be found on the SCAQMD's CEQA webpage at the following internet address: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency/comment-letter-year-2014.

In addition, SCAQMD staff has been working on a Warehouse Truck Trip Study to better quantify trip rates associated with local warehouse and distribution projects, as truck emissions represent more than 90 percent of air quality impacts from these projects. Draft final results for the Warehouse Truck Trip Study are completed and are lower than current SCAQMD recommended truck trip rates in the California Emissions Estimator Model (CalEEMod).

SCAQMD Lead Agency Projects (Attachment C) – Pursuant to CEQA, the SCAQMD periodically acts as lead agency for stationary source permit projects. Under CEQA, the lead agency is responsible for determining the type of CEQA document to be prepared if the proposal is considered to be a "project" as defined by CEQA. For example, an Environmental Impact Report (EIR) is prepared when the SCAQMD, as lead agency, finds substantial evidence that the proposed project may have significant adverse effects on the environment. Similarly, a Negative Declaration (ND) or Mitigated Negative Declaration (MND) may be prepared if the SCAQMD determines that the proposed project will not generate significant adverse environmental impacts, or the impacts can be mitigated to less than significance. The ND and MND are written statements describing the reasons why proposed projects will not have a significant adverse effect on the environment and, therefore, do not require the preparation of an EIR.

Attachment C to this report summarizes the active projects for which the SCAQMD is lead agency and is currently preparing or has prepared environmental documentation. Through the end of October, the SCAQMD certified one permit project on October 10, 2014. As noted in Attachment C, through the end of October 2014, the SCAQMD continued working on the CEQA documents for ten active projects.

Through the end of October 2014, SCAQMD staff has been responsible for preparing or having prepared CEQA documents for eleven permit application projects.

Attachments

A. Incoming CEQA Documents Log

B. Ongoing Active Projects for Which SCAQMD Has or Will Conduct a CEQA Review

C. Active SCAQMD Lead Agency Projects

ATTACHMENT A* INCOMING CEQA DOCUMENTS LOG OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Goods Movement **LAC141003-05** Mitsubishi Cement (MCC Cement Facility) #	The proposed project consists of modifications to the existing cement import facility located at 1150 Pier F Avenue. The project would include installation of a vessel at-berth emission control system, construction of additional cement storage and truck loading silos on an adjacent lot, and upgrades to ship unloading equipment and other landside structures. Comment Period: 10/3/2014 - 11/18/2014 Public Hearing: 10/22/2014	Draft Environmental Impact Report	Port of Long Beach	Document under review as of 10/31/14
Goods Movement **LAC141007-04** Berths 212-224 (YTI) Container Terminal Improvements Project #	The proposed project consists of improving the container-handling efficiency of the existing YTI Terminal at the Port to accommodate the projected fleet mix of larger container vessels (up to 13,000 TEUs) that are anticipated to call at the YTI Terminal through 2026. The proposed Project consists of deepening two existing berths (Berths 217–220 and Berths 214–216), which would add an additional operating berth to the YTI Terminal, extending the 100-foot gauge crane rail to Berths 217–220, adding a single operational rail track to the Terminal Island Container Transfer Facility (TICTF) on-dock rail, modifying and replacing cranes, and constructing backland improvements. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/feiryti212-224.pdf http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/ytifeireis103014.pdf Comment Period: N/A Public Hearing: 11/7/2014	Final Environmental Impact Report	Port of Los Angeles	SCAQMD staff commented 10/30/2014 SCAQMD Staff Testified 10/16/14
Goods Movement **LAC141023-08** Avalon Freight Services Relocation Project	The proposed project consists of landside and waterside improvements at Berth 95, including the construction of a 20,000 square-foot warehouse/office space in the existing parking structure at Berth 95. Waterside improvements would be made to accommodate one new barge and tug boat, and one new landing craft. The waterside improvements include the installation of approximately 22 pilings to secure three new floats as well as some minor modifications to the existing boat launch ramp. Comment Period: 10/23/2014 - 11/22/2014 Public Hearing: N/A	Draft Negative Declaration	Port of Los Angeles	Document under review as of 10/31/14
Goods Movement **LAC141024-03** 226-236 (Everport) Container Terminal Improvements Project #	The proposed project consists of the construction and operation of terminal improvements within and adjacent to the Everport Container Terminal. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopberth226-236.pdf Comment Period: 10/24/2014 - 11/24/2014 Public Hearing: N/A	Notice of Preparation	Port of Los Angeles	SCAQMD staff commented 10/31/2014
Warehouse & Distribution Centers **SBC141003-06** Prologis	The proposed project consists of developing four warehouse distribution facilities totaling 1,529,498 square feet with building sizes that range from 160,106 to 862,035 square feet on 84 acres. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/feirprologis.pdf Comment Period: N/A Public Hearing: N/A	Revised Final Environmental Impact Report	City of Moreno Valley	SCAQMD staff commented 10/10/2014

**Sorted by Land Use Type (in order of land uses most commonly associated with air quality impacts), followed by County, then date received.*

\# - Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Warehouse & Distribution Centers **SBC141024-02** Modular Logistics Center	The proposed project consists of the redevelopment of an underutilized 50.84 gross-acre property. The redevelopment process would involve the demolition and removal of existing industrial buildings and associated improvements from the subject property, grading and preparation for the redevelopment, and construction and operation of a logistics warehouse structure containing 1,109,378 square feet of building space and 26 loading bays. Comment Period: 10/24/2014 - 12/8/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Moreno Valley	Document under review as of 10/31/14
Warehouse & Distribution Centers **SBC141030-01** Goodman Logistics Center	The proposed project consists of constructing a new business park development totaling approximately 1,230,585 square feet of floor area. The project will involve the construction of three new concrete tilt-up industrial warehouse buildings. Comment Period: 10/30/2014 - 11/28/2014 Public Hearing: N/A	Notice of Preparation	City of Santa Fe Springs	Document under review as of 10/31/14
Airports **ALL141028-01** Southern California Optimization of Airspace and Procedures in the Metropolex (SoCal OAPM) Project Briefings Notifications	The proposed project consists of changes in aircraft flight paths and/or altitudes in certain areas, but would not require any ground disturbance nor increase the number of aircraft operations within the Southern California Metroplex area. Comment Period: N/A Public Hearing: N/A	Initial Project Consultation	U.S. Department of Transportation	Document does not require comments
Industrial and Commercial **LAC141022-02** Irwindale Olive Pit	See Record LAC140815-05. SCAQMD Staff provided comments on the DEIR on 8/15/14. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/september/deirolive.pdf. The City of Baldwin Park provided SCAQMD with their comments on the Draft EIR. Comment Period: N/A Public Hearing: N/A	Comments to Draft EIR.	City of Irwindale	Document screened - No further review conducted
Industrial and Commercial **RVC141016-10** Mt. San Jacinto Winter Park Authority Valley Station Zip Line Project	The proposed project consists of constructing a recreational zip line facility adjacent to the valley station employee parking lot at the Palm Springs Aerial Tramway. The project would consist of a take-off platform, and include a hillside drop-point anchored into native rock with an elevation gain of approximately 106.7 feet and horizontal distance of approximately 500+ feet. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/ndvalleyzip.pdf Comment Period: 10/22/2014 - 11/10/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	Mt. San Jacinto Winter Park Authority	SCAQMD staff commented 10/30/2014
Industrial and Commercial **SBC141014-03** Perricone Juices	The proposed project consists of a site plan review of a 20,604 square-foot addition at an existing juice processing facility. Comment Period: 10/10/2014 - 10/31/2014 Public Hearing: N/A	Initial Project Consultation	City of Beaumont	Document screened - No further review conducted

\# - Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER / PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Industrial and Commercial **SBC141021-03** MA14117	The proposed project consists of the construction of a new 32,800 square-foot industrial building to be used for manufacturing concrete, gypsum, plaster and mineral products. Outside storage of finished material is also being proposed. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopma14117.pdf Comment Period: 10/21/2014 - 10/28/2014 Public Hearing: N/A	Initial Project Consultation	City of Jurupa Valley	SCAQMD staff commented 10/30/2014
Industrial and Commercial **SBC141021-06** MA14126 (Site Development Permit No. 31436)	The proposed project consists of two new industrial buildings. Building one will be 607,140 square feet and building two will be 518,960 square feet. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/warehouse14126.pdf Comment Period: N/A Public Hearing: N/A	Initial Project Consultation	City of Jurupa Valley	SCAQMD staff commented 10/30/2014
Waste and Water-related **LAC141002-08** AAD Distribution and Dry Cleaning Services, Inc. Proposed Consent	The proposed project consists of the Second Settlement and Consent Decree regarding the former AAD Distribution and Dry Cleaning Services, Inc located in Vernon. The proposed Consent Decree resolves claims against Archipel, Inc. and related companies for their contributions to contamination at the site as a result of sending hazardous waste to the AAD facility. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dtscaaddry.pdf Comment Period: 9/12/2014 - 10/13/2014 Public Hearing: N/A	Public Notice	Department of Toxic Substances Control	SCAQMD staff commented 10/15/2014
Waste and Water-related **LAC141003-02** Royal Recycling and Transfer Facility	The proposed project consists of permitting the operation of a materials recovery facility. The proposed use will occupy a number of existing buildings that have a total floor area of 146,600 square feet. In addition, a new "receive building" consisting of 39,500 square feet will be constructed. Total floor area of the existing and new buildings will be 186,100 square feet. Comment Period: 10/2/2014 - 11/17/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Paramount	Document under review as of 10/31/14
Waste and Water-related **LAC141007-03** Former Southland Steel Facility 5959-6161 Alameda Avenue, Huntington Park	The proposed project consists of the Final Response Plan for the Former Southland Steel Facility. This document consists of responses to comments. Comment Period: N/A Public Hearing: N/A	Response to Comments	Department of Toxic Substances Control	Document screened - No further review conducted
Waste and Water-related **LAC141007-05** Line 63 Re-Route Project	The proposed project consists of a 2.27-mile long re-route of a segment of a petroleum pipeline (line 63) and approximately 2,000 linear feet of Horizontal Directional Drilling. The new locations would avoid a concentration of geologic hazards located along the existing Line 63 alignment, within a deep canyon between Fisher Springs Road and the Old Ridge Route. The proposed action would relocate the pipeline into a previously disturbed pipeline corridor, along an existing oil pipeline. The re-route alignment is proposed based on the presence of fewer geologic hazards, accessibility and constructability of the route. Comment Period: N/A Public Hearing: N/A	Draft Environmental Assessment	United States Department of Agriculture	Document reviewed - No comments sent

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Waste and Water-related **LAC141007-08** Ascon Landfill Site	The proposed project consists of considering an inclusion of an additional truck haul route needed to address short-term traffic impacts previously analyzed in the Draft EIR. Comment Period: 10/6/2014 - 11/21/2014 Public Hearing: 11/6/2014	Community Notice	Department of Toxic Substances Control	Document reviewed - No comments sent
Waste and Water-related **LAC141008-02** Renu Plating Company, Inc. Site, Los Angeles, California	The proposed project consists of a proposed Consent Decree with the Renu Plating Company, Inc. The proposed Consent Decree resolves DTSC's claims against Lichtbachs under the Comprehensive Environmental Response, Compensation, and Liability Act. The Litchtbachs owned the Site from approximately 1980 to 1986 and were named as defendants in DTSC's lawsuit filed to recover DTSC's costs of investigating and cleaning up hazardous substances released at the Site. Comment Period: 10/8/2014 - 11/10/2014 Public Hearing: N/A	Community Notice	Department of Toxic Substances Control	Document screened - No further review conducted
Waste and Water-related **LAC141009-06** CUP No. 6222, 3420, 3500, 4401 and 4500	The proposed project consists of allowing the repair and replacement of facilities within the Arroyo Seco Canyon Area that were damaged or destroyed by Station Fire-related events of 2009. Comment Period: 10/9/2014 - 11/8/2014 Public Hearing: 11/19/2014	Draft Mitigated Negative Declaration	City of Pasadena	Document screened - No further review conducted
Waste and Water-related **LAC141009-08** California School for the Deaf - Riverside Draft Removal Action Workplan (RAW)	The proposed project consists of the RAW clean up plan of contaminated soil at the California School for the Deaf - Riverside site. Lead, arsenic, and pesticides were found at elevated levels in soil on the Site. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dtscrawschofdeafrivdoc.pdf Comment Period: 10/9/2014 - 11/8/2014 Public Hearing: N/A	Community Notice	Department of Toxic Substances Control	SCAQMD staff commented 10/21/2014
Waste and Water-related **LAC141014-05** Santa Susana Field Laboratory Area IV	This document consists of a Class 1 Modification Request. The proposed project consists of a Class 1 permit modification for each facility to request DTSC approval of the operator transfer from Boeing to North Winds Inc. (NWI). The modification request included revised Part A forms with the name and contact information of the new operator NWI. Comment Period: N/A Public Hearing: N/A	Other	Department of Energy	Document screened - No further review conducted

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Waste and Water-related **LAC141016-08** Saugus Industrial Center, Former Keysor-Century Corporation Facility - Draft Remedial Action Plan	The proposed project consists of a Draft Remedial Action Plan for the clean up of soil and groundwater at the Saugus Industrial Center, formerly known as the Keysor-Century Corporation Facility. Comment Period: 10/15/2014 - 11/17/2014 Public Hearing: N/A	Community Notice	Department of Toxic Substances Control	Document under review as of 10/31/14 Fact Sheet
Waste and Water-related **LAC141017-05** Santa Anita Stormwater Flood Management and Seismic Strengthening Project	The proposed project consists of modifying existing flood management and water conservation facilities along the Santa Anita Canyon Watershed, including the Santa Anita Dam, the Santa Anita Headworks, the Wilderness Park Culbert Crossing, and the Santa Anita Debris Dam. The improvements would: 1) reduce flood risk to downstream communities; 2) enhanced sustainability of the local water supply and increased recharge to the groundwater basin by over 500 acre-feet per year; 3) improve all-weather access to the Arcadia Wilderness Park by constructing a new culvert crossing. Comment Period: 10/17/2014 - 12/4/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	County of Los Angeles	Document screened - No further review conducted
Waste and Water-related **LAC141021-05** Devil's Gate Reservoir Sediment Removal and Management Project	The proposed project consists of removing sediment from Devil's Gate Reservoir to restore capacity and to protect the dam and its valves to reduce the risk of flooding in the communities located downstream. This effort will include removal of approximately 2.9 million cubic yards of existing excess sediment in the reservoir in addition to any additional sediment that accumulates during construction. Comment Period: N/A Public Hearing: 11/12/2014	Response to Comments	Los Angeles County Flood Control District	Document screened - No further review conducted
Waste and Water-related **LAC141021-11** Soil Remediation at Berths 171-173	The proposed project consists of soil remediation at Berths 171-173. Comment Period: N/A Public Hearing: 11/20/2014	Notice of a Public Hearing	Port of Los Angeles	Document screened - No further review conducted
Waste and Water-related **LAC141021-12** F.E. Weymount Treatment Plant Improvement Program	The proposed project consists of upgrading existing and/or constructing new facilities at the Weymouth Plan to accommodate the plant's maximum operating capacity and update the overall facility. The project would involve rehabilitating and refurbishing aging treatment structures, upgrading systems to improve treatment processes, enhancing worker safety, reducing carbon emissions with renewable energy, improving stormwater management, and ensuring compliance with recent legislation pertaining to the State Drinking Water Act. Comment Period: 10/21/2014 - 12/6/2014 Public Hearing: N/A	Draft Environmental Impact Report	Metropolitan Water District of Southern California	Document under review as of 10/31/14

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

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Waste and Water-related **LAC141022-03** Irwindale Material Recovery Facility Transfer Station	See Record LAC140808-02. SCAQMD staff provided comments on DEIR on 8/8/14. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/september/deirirwinmrf.pdf The City of Baldwin Park provided SCAQMD with their comments on the Draft EIR. Comment Period: N/A Public Hearing: N/A	Comments to Draft EIR	City of Irwindale	Document screened - No further review conducted
Waste and Water-related **LAC141023-09** Cleanup Plan for Groundwater at the KB Gardena Building, LLC Site in Gardena	The proposed project consists of a Removal Action Workplan to clean up the groundwater at the KB Gardena building site. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dtscrawkbgardena.pdf Comment Period: 10/24/2014 - 11/24/2014 Public Hearing: N/A	Community Notice	Department of Toxic Substances Control	SCAQMD staff commented 10/31/2014
Waste and Water-related **RVC141002-09** Semi-Annual Depth to Groundwater Measurements	The proposed project consists of a Class 1 permit modification to the Department of Toxic Substances Control. The modification will allow for transitioning from quarterly measurements. This modification will not affect any of the current operations at the facility. Comment Period: N/A Public Hearing: N/A	Public Notice	Department of Toxic Substances	Document screened - No further review conducted
Waste and Water-related **RVC141030-03** Remedial Action Plan for Laborde Canyon (Lockheed Propulsion - Beaumont No. 2)	The proposed project consists of the cleanup on the Laborde Canyon Site, also known as Lockheed Propulsion - Beaumont No. 2, located in Riverside County. The proposed cleanup includes remediation of contaminated soil and groundwater. Comment Period: 10/30/2014 - 12/4/2014 Public Hearing: N/A	Notice of Preparation	Department of Toxic Substances Control	Document under review as of 10/31/14
Waste and Water-related **SBC141017-02** Mid-Valley Landfill Permit Revision Project	The proposed project consists of modifying the landfill operation hours to allow for 24-hour per day operations, Monday and Saturday. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopmidvalley.pdf Comment Period: 10/17/2014 - 11/13/2014 Public Hearing: N/A	Notice of Preparation	County of San Bernardino	SCAQMD staff commented 10/24/2014
Waste and Water-related **SBC141029-01** Lake Gregory Regional Park (Houston Creek), Crestline, CA 92325	The proposed project consists of meeting state mandated dam seismic safely standards that require the ability to lower the water level of a reservoir by half capacity over a period of seven days. Once the project is built, the improved outlet works would be adequately maintained, easily accessible, and allow for the management of water levels as required by the State's Department of Water Resources Division of Safety of Dams. Comment Period: 10/29/2014 - 12/29/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	County of San Bernardino	Document reviewed - No comments sent

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Utilities **LAC141016-03** ENV-2014-2730/ 4977 W. Washington Blvd; West Adams-Baldwin Hills-Leimert	The proposed project consists of the construction, use and maintenance of a wireless telecommunication facility consisting of 12 panel antennas on a 50-foot high monopine structure and an approximately 350 square-foot at-grade equipment cabinet. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nd4977wwashing.pdf Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/30/2014
Utilities **LAC141023-05** ENV-2014-2492/ 505 S. San Pedro St.: Central City	The proposed project consists of a permit to install, use and maintain a new unmanned wireless telecommunication facility comprised of 11 panel antennas, 24 remote radio units, three GPS antennas, with supportive equipment, all on the rooftop of an existing 75-foot tall residential building. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
Transportation **LAC141017-01** Project Nos. 1043, 1492 and 1493	The proposed project consists of improvements to a 1.75-mile segment of Carson Street between I-405 and I-110 implementing the Carson Street Master Plan. Majority of the improvements on Carson Street will be within the public right of way including, widening of sidewalks, installing on traffic signals, installing fiber optic conduit, modifications to medians and driveways, re-pavement of the travel lanes, modifications to on-street parking, decorative crosswalks, addition of landscaping and irrigation waterline, and street furniture such as monuments, pedestrian and auto oriented lights and art pieces, bike racks, benches, wayfaring signs bus shelters, trash receptacles, etc.	Draft Negative Declaration	City of Carson	Document screened - No further review conducted
Transportation **ORC141007-02** Park Avenue Bridge Replacement Project	The proposed project consists of demolition of the existing Park Avenue Bridge and construction of an improved seismically-reinforced bridge over the Grand Canal. The new bridge would include 11-foot vehicle lanes, six-foot raised sidewalks, and ADA compliant switchback ramps. Comment Period: 10/6/2014 - 11/5/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Newport Beach	Document screened - No further review conducted
Transportation **RVC141010-01** Squaw Mountain Road Bridge Repair Report	The proposed project consists of repairs to lining of the channel bottom below the bridge with concrete, connecting the concrete-lined channel to the existing bridge abutment, placing 1/4-ton of rock that will be used to stablize streambed on the upstream and downstream sides of the concrete-lined portion of the channel, and installing riprap slope protection on the northwest slope. An existing asphalt access road would be extended approximately 40 feet. Comment Period: 10/7/2014 - 11/6/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	County of Riverside	Document screened - No further review conducted

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Transportation **SBC141007-07** High Desert Corridor Project	The proposed project consists of a Strategic Multipurpose corridor that might include highway, toll way, High Speed Rail, bikeway and green energy production/transmission elements extending 63 miles between State Route 14 in Los Angeles County and San Bernardino County. Comment Period: 10/7/2014 - 12/2/2014 Public Hearing: 12/2/2014	Notice of a Public Hearing	California Department of Transportation	Document screened - No further review conducted
Institutional (schools, government, etc.) **LAC141010-03** Heritage Castle Museum	The proposed project would consist of the Heritage Castle Museum that would occupy a 2,690 square-foot portion of the existing Harden Estate gatehouse. An existing barn will be removed from the grounds. All other alterations to the structure and site are proposed to occur inside of the existing gatehouse building. Comment Period: 10/10/2014 - 11/10/2014 Public Hearing: 10/28/2014	Notice of Availability of a Draft Mitigated Negative Declaration	City of Rancho Palos Verdes	Document screened - No further review conducted
Institutional (schools, government, etc.) **LAC141014-01** Mandarin and English Dual-Language Immersion Elementary School Project at Mark Twain Middle School	The proposed project consists of a new classroom building consisting of approximately 15 classrooms, a multi-purpose room, and administrative and support spaces; new food services and lunch shelter facilities; designated elementary and kindergarten play areas; designated student drop-off and parking areas; and modifications to approximately eight existing portable classrooms. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopmandengsch.pdf Comment Period: 10/14/2014 - 11/12/2014 Public Hearing: N/A	Notice of Preparation	Los Angeles Unified School District	SCAQMD staff commented 10/21/2014
Institutional (schools, government, etc.) **LAC141021-08** Malibu Institute	The proposed project consists of reconfiguring lot lines of 29 existing lots to create a total of seven lots over the 650-acre project site. Comment Period: N/A Public Hearing: 11/19/2014	Notice of a Public Hearing	County of Los Angeles	Document screened - No further review conducted
Institutional (schools, government, etc.) **LAC141021-13** Long Beach Courthouse Demolition Project	The proposed project consists of demolishing the former Long Beach Courthouse building and would entail the removal of reinforced concrete, structural steel, siding, glass, and other building materials from the project site. Comment Period: 10/14/2014 - 12/1/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Long Beach	Document under review as of 10/31/14

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Institutional (schools, government, etc.) **LAC141022-01** Los Angeles Street Civic Building Project	The proposed project consists of reactivating the existing Parker Center Property to provide office space for City of Los Angeles employees. Three potential build alternatives are considered and are as follows: Rehabilitation with various improvements; Partial Demolition Rehabilitation, and Addition, which includes rehabilitation of majority of the building combined with an expansion of 522,255 square feet; and Demolition and Build, which includes full demolition and construction of 753,753 square feet. Comment Period: N/A Public Hearing: 10/28/2014	Response to Comments	City of Los Angeles	Document does not require comments
Institutional (schools, government, etc.) **ORC141007-01** Mater Dei High School Parking Structure and School Expansion Project	The proposed project consists of constructing a three-level parking structure east of the school's existing campus and a two-story classroom building within the boundaries of the existing campus. No change to the school's existing operations would occur; however, maximum student enrollment is proposed to be increased from 2,200 students to 2,500 students. The addition of the proposed parking structure would increase the size of the campus from approximately 21 acres to 25 acres. Comment Period: 10/6/2014 - 11/19/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Santa Ana	Document screened - No further review conducted
Medical Facility **LAC141030-02** Development Plan Approval Case No. 881 and Environmental Document	The proposed project consists of the development plan approval and construction of an approximately 35,076 square-foot three-story Medical Office Building for outpatient uses, and appurtenant improvements, on the 2.327-acre property. Comment Period: N/A Public Hearing: 11/10/2014	Notice of a Public Hearing	City of Santa Fe Springs	Document does not require comments
Retail **LAC141002-02** ENV-2013-2369/ 12625-33 N. Glenoaks Blvd. and 14071 W. Hubbard St; Sylmar	The proposed project consists of a new gas station in conjunction with Food 4 Less grocery store to include (1) 92 feet x 43 feet fueling canopy, (1) 173 square-foot kiosk with restroom, five gas dispensers, two underground storage tanks and associated fueling components, trash enclosure, monument sign and additional signage on fueling canopy and kiosk, and an air/water unit. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndglendoaks.pdf Comment Period: 10/2/2014 - 11/3/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/10/2014
Retail **LAC141002-03** ENV-2014-2513/ 13673-13689 West Foothill Boulevard, Sylmar	The proposed project consists of the demolition of one-story, commercial building and the construction of a 2,240 square-foot Starbucks Coffee and a 5,500 square-foot building, for a total of 7,740 square feet. Comment Period: 10/2/2014 - 11/3/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted

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Retail **LAC141002-07** ENV-2014-1277/ 5600, 5602 W. Hollywood Blvd. and 1669, 1671, 1673, 1675, 1677, 1679 and 1681 N. St. Andrews Pl.; Hollywood	The proposed project consists of the construction, use and maintenance of a boutique hotel with 80 guestrooms and 867 square feet of restaurant space. The new hotel will be six-stories, 75 feet in height and consists of 26,671 square feet of floor area on an approximately 9,514 square-foot site. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndhollywood.pdf Comment Period: 10/2/2014 - 11/3/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/10/2014
Retail **LAC141029-02** Valencia Boulevard Gas Station	The proposed project consists of the construction of a new fueling station and 6,000 square-foot commercial building, consisting of a convenience store, restaurant, and office. Comment Period: 10/28/2014 - 11/18/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Santa Clarita	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141001-04** 550 N. Third Street Project	The proposed project consists of constructing a mixed-use development with 97 apartment units and 1,526 square feet of retail space in a single structure consisting of six stories over a subterranean and semi-subterranean parking structure. Comment Period: 10/1/2014 - 10/14/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Burbank	Document reviewed - No comments sent
General Land Use (residential, etc.) **LAC141002-01** ENV-2011-1535-REC-1/ 1019-2068 South La Cienega Boulevard & 1036-1046 Corning Street; Wilshire	The proposed project consists of allowing the continued use and operation of an existing synagogue and school together with the expansion of accessory school uses for the addition demolition of existing Pressmen Early Childhood Center and five residential buildings on the site and the construction of a new two-story, 21,000 square-foot building with eight classrooms with an 8,500 square-foot outdoor play area and a surface parking lot with 27 parking spaces. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndenv20111535.pdf Comment Period: 10/2/2014 - 10/22/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/9/2014
General Land Use (residential, etc.) **LAC141002-04** ENV-2014-2360/ 6939 N. Van Nuys Blvd.; Van Nuys-North Sherman Oaks	The proposed project consists of expanding an existing banquet hall into the adult day care facility and the construction of a two-story, 4,280 square-foot addition to the existing 10,476 square-foot building; resulting in a 14,756 square-foot banquet hall. Comment Period: 10/2/2014 - 10/22/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted

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General Land Use (residential, etc.) **LAC141002-05** ENV-2010-3311/ 3460 N. Beverly Glen Blvd; Sherman Oaks-Studio City-Toluca Lake-Caguenga Pass	The proposed project consists of a Preliminary Parcel Map to subdivide a circular shaped property into three lots for the construction and use of the single-family homes on a 3.29-acre vacant site. Comment Period: 10/2/2014 - 10/22/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141002-06** ENV-2014-930/ 2754 N. Rinconia Dr.; Hollywood	The proposed project consists of an addition of 4,447 square feet to an existing 1,154 square-foot single-family dwelling on a 1/4-acre lot. Comment Period: 10/2/2014 - 10/22/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141003-01** El Serano Park Improvement Project	The proposed project consists of replacing the existing Clubhouse and the adjacent paved area with several new recreational facilities within El Serano Recreation Center and Park. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopelsereno.pdf Comment Period: 10/2/2014 - 11/3/2014 Public Hearing: N/A	Notice of Preparation	City of Los Angeles	SCAQMD staff commented 10/10/2014
General Land Use (residential, etc.) **LAC141003-04** La Plaza Cultura Village Project	The proposed project consists of a lease agreement between the County and the La Plaza de Cultura y Artes Foundation to permit the development and use of a mixed-use project. The project would establish a mixed-use, transit-oriented infill development totaling approximately 425,000 square feet, including up to 345 residential units (for lease) with 20 percent of the units reserved as affordable units, together with up to 55,000 square feet of visitor-serving retail including, but not limited to, a restaurant, a café, other food services, and a "commissary" or shared kitchen space for culinary demonstrations and use by small businesses. Comment Period: N/A Public Hearing: N/A	Final Environmental Impact Report	County of Los Angeles	Document reviewed - No comments sent
General Land Use (residential, etc.) **LAC141007-06** San Bernardino Residential Town-Homes (Bella Vista Specific Plan)	The proposed project consists of demolishing existing buildings and accessory structures at the project site, The proposed development would provide 135 town-home units within the 6.49-acre site. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndbellavista.pdf Comment Period: 10/9/2014 - 10/28/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of West Covina	SCAQMD staff commented 10/16/2014
General Land Use (residential, etc.) **LAC141009-01** ENV-2014-856/ 1430 N. Eaton Terrace; Northeast Los Angeles	The proposed project consists of the construction, use and maintenance of a new 2,476 square-foot single-family dwelling with an attached 237 square-foot, two-car garage. Comment Period: 10/9/2014 - 11/10/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted

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General Land Use (residential, etc.) **LAC141009-02** ENV-2014-2433/ 1531 West Sunset Blvd.; Silver Lake-Echo Park-Elysian Valley	The proposed project consists of expanding an existing restaurant from 685 square feet to 2,031 square feet. Comment Period: 10/9/2014 - 10/29/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141009-03** ENV-2014-200/ 1550 West 8th Street; Westlake	The proposed project consists of the demolition of the existing 11,100 two-story square-foot building and the construction of a 45,770 four-story square-foot building and removal of the adjacent surface parking lot. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nd1550w8th.pdf Comment Period: 10/9/2014 - 10/29/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/30/2014
General Land Use (residential, etc.) **LAC141009-04** ENV-2014-2487/ 7734 N. Varna Ave.; Sun Valley-La Tuna Canyon	The proposed project consists of subdividing a single 24,818 square-foot lot into three lots for the development of two new single-family residences. Comment Period: 10/9/2014 - 10/29/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141009-07** Enclave Multifamily Residence Project	The proposed project consists of development of a five-story apartment building with 71 multi-family residential units on a 0.72-acre parcel. Comment Period: 10/9/2014 - 11/7/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Glendale	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141010-02** Redondo Beach's California Environmental Quality Act Procedures	The proposed project consists of amending the City's CEQA procedures contained in Title 10 Chapter 3. Comment Period: 10/10/2014 - 10/21/2014 Public Hearing: 10/21/2014	Notice of a Public Hearing	City of Redondo Beach	Document reviewed - No comments sent
General Land Use (residential, etc.) **LAC141014-02** City Ventures La Habra Civic Center Infill Housing Project	The proposed project consists of developing approximately 5.5 acres within and adjacent to the City of La Habra Civic Center. http://www.aqm.gov/docs/default-source/ceqa/comment-letters/2014/october/nopcityventlahabra.pdf Comment Period: 10/14/2014 - 11/12/2014 Public Hearing: N/A	Notice of Preparation	City of La Habra	SCAQMD staff commented 10/21/2014

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General Land Use (residential, etc.) **LAC141014-04** 5833 Crest Road Project (PA-25-14)	The proposed project consists of the construction of four two-story, detached patio homes. The proposed homes would be approximately 3,295 square feet in floor area on a 0.51-acre site. Comment Period: 10/9/2014 - 11/24/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Rolling Hills	Document reviewed - No comments sent
General Land Use (residential, etc.) **LAC141016-01** ENV-2014-1618/ 3419-3429 West 6th Street (544-550 South Kenmore Avenue); Wilshire	The proposed project consists of constructing 53 residential units within a three-story building above an existing four-story parking structure with ground floor and basement level commercial uses, for a total of seven. Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141016-02** ENV-2014-2498/ 2424 South 4th Avenue; West Adams-Baldwin Hills-Leimert	The proposed project consists of a condominium conversion of an existing four-unit historic building known as the Roberta Apartments and identified as Los Angeles Cultural Monument #1065. Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141016-04** ENV-2006-7211/ 805-823 S. Catalina St. and 806-820 S. Kenmore Ave.; Wilshire	The proposed project consists of the construction of a mixed-use building with 27 stories of 300.5 feet in height, 269 residential units, 7,500 square feet of ground/second floor retail space, and 562 parking spaces, including two subterranean levels. Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141016-05** ENV-2014-977/ 2056 N. Morgan Hill Dr.; Hollywood	The proposed project consists of a second story single-family addition over a basement. Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document reviewed - No comments sent

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General Land Use (residential, etc.) **LAC141016-07** ENV-2014-1780/ 9309 W. Sierra Mar Dr.; Hollywood	The proposed project consists of a remodel and a 1,007 square-foot addition to an existing single-family dwelling. The project includes the demolition of an existing garage, installation of a new elevator, and the construction of a new pool. A total of approximately 780 cubic yards will be graded as a part of the project. The project may require haul route approval. Comment Period: 10/16/2014 - 11/5/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141016-09** 515 W. Broadway Mixed-Use Project	The proposed project consists of a mix of multi-family and single-family development on 1.78 acres. The Project includes the development of a five-story mixed-use building with 180 multi-family residential dwelling units and 18,200 square feet of ground-floor commercial space. Comment Period: 10/15/2014 - 11/14/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Glendale	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141021-09** Gordon Mull Subdivision	The proposed project consists of grading and installing of infrastructure improvements to create 19 defined building pads to be developed with two-story single-family residences. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopgordon.pdf Comment Period: 10/20/2014 - 11/19/2014 Public Hearing: N/A	Notice of Preparation	City of Glendora	SCAQMD staff commented 10/24/2014
General Land Use (residential, etc.) **LAC141023-01** ENV-2014-3003/ 11135-11145 West Burbank Boulevard; North Hollywood-Valley Village	The proposed project consists of demolishing seven commercial and residential buildings and the construction, use and maintenance of a 38,531 square-foot, four-story, 53-foot tall, 70-room hotel. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141023-02** ENV-2014-1057/ 22 N. Latimer Rd.; Brentwood-Pacific Palisades	The proposed project consists of a new 6,000 square-foot, two-story, single-family residence with swimming pool and spa. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141023-03** ENV-2014-1751/ 6724 N Allott Ave.; Van Nuys-North Sherman Oaks	The proposed project consists of subdividing an existing 33,159 square-foot lot into three lots, and the construction of one single-family dwelling. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Environmental Assessment	City of Los Angeles	Document screened - No further review conducted

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
General Land Use (residential, etc.) **LAC141023-04** ENV-2014-2443/ 841 E. 4th Pl; Central City North	The proposed project consists of restoring and converting an existing warehouse building into 78,600 square feet of office uses, 25,000 square feet of retail, and 20,000 square feet of restaurant uses. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141023-06** ENV-2014-4000/ 360 S. Alameda St. and 125 Industrial St.; Central City North	The proposed project consists of two development projects. The project at 31525 Industrial Street proposes construction of a seven-story mixed use building with 360 live-work units and 11,575 square feet of commercial space. The project at 360 South Alameda proposes construction of a six-story mixed-use building with 63 live/work units and 2,500 square feet of commercial space. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141023-07** ENV-2014-2382/ 4422 W. Adams Boulevard, Los Angeles, CA	The proposed project consists of the construction and operation of a 4,886 square-foot commercial coin-operated laundry mart with 18 on-site parking space on an approximately 12,500 square-foot site. Comment Period: 10/23/2014 - 11/12/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	Document screened - No further review conducted
General Land Use (residential, etc.) **LAC141024-01** Flair Spectrum Project	The proposed project consists of a mixed-use development consisting of 640,000 gross square feet of retail and 50,000 square feet of restaurant for an outlet mall, a 250-room hotel, and 600 residential units on the 14.6-acre project site. Comment Period: 10/24/2014 - 12/8/2014 Public Hearing: N/A	Notice of Availability of a Draft Environmental Impact Report	City of El Monte	Document under review as of 10/31/14
General Land Use (residential, etc.) **LAC141024-04** Palladium Residences	The proposed project consists of a mixed-use development on an approximately 3.6-acre parcel. The project includes two development options to provide flexibility for changing market conditions. Option 1, Residential, the Project would contain up to 731 residential units. Under Option 2, Residential/Hotel, the Project would provide up to 598 residential units and a 250-room hotel with related hotel facilities such as a banquet and meeting area. Comment Period: 10/23/2014 - 12/8/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Los Angeles	Document under review as of 10/31/14
General Land Use (residential, etc.) **ODP141008-01** CEQA Alternatives Screening Report for South Orange County Reliability Enhancement EIR	The proposed project consists of a report of the screening analysis of project alternatives to be evaluated in the Environmental Impact Report for the South Orange County Reliability Enhancement project. Comment Period: N/A Public Hearing: N/A	Other	California Public Utilities Commission	Document screened - No further review conducted

- Project has potential environmental justice concerns due to the nature and/or location of the project.

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ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
General Land Use (residential, etc.) **ORC141001-01** Alta Vista Way Retaining Wall Project	The proposed project consists of installing a secant pile retaining wall within the street, approximately where the existing curb and gutter is situated. The existing timber retaining wall would be protected-in-place and no modifications to the retaining wall would occur. Upon completion of the proposed project, the roadway, curb, and gutter would be restored to pre-project conditions. Comment Period: 10/1/2014 - 10/30/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Laguna Beach	Document screened - No further review conducted
General Land Use (residential, etc.) **ORC141001-03** Parkside at Baker Ranch Residential	The proposed project consists of closure and reclamation of the existing surface mine, and the construction of up to 250 single and multi-family attached and detached residential units on the approximately 30-acre project site. Comment Period: 9/10/2014 - 10/9/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Lake Forest	Document reviewed - No comments sent
General Land Use (residential, etc.) **ORC141007-10** Title Settlement and Land Exchange Agreement (Department of Water and Power Specific Plan Amendment Project)	This document consists of a Notice of Intent to consider an Addendum to certified FEIR. The proposed project consists of consideration of a compromise Title Settlement and Land Exchange Agreement regarding certain interests in public trust lands within the Project area prior to implementation of a proposed residential development as part of the Department of Water and Power Specific Plan Amendment Project. Comment Period: N/A Public Hearing: 10/14/2014	Other	California State Lands Commission	Document reviewed - No comments sent
General Land Use (residential, etc.) **ORC141031-01** The Preserve at San Juan, Orange County, California	The proposed project consists of construction of 72 single-family residences on 583.3 acres in an unincorporated portion of Orange County. Comment Period: 10/31/2014 - 12/1/2014 Public Hearing: N/A	Revised Notice of Preparation	County of Orange	Document under review as of 10/31/14
General Land Use (residential, etc.) **RVC141007-09** Change of Zone 07849	The proposed project consists of a permit for change of zone for the proposed project site from Agriculture to Commercial Retail. Comment Period: 10/7/2014 - 10/23/2014 Public Hearing: N/A	Initial Project Consultation	County of Riverside	Document screened - No further review conducted
General Land Use (residential, etc.) **RVC141021-04** Planning Application PA10-0213, Simms Tract Map (No. 36218)	The proposed project consists of a Tentative Tract Map to create seven residential lots for single-family dwelling units. Comment Period: N/A Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Temecula	Document screened - No further review conducted

- Project has potential environmental justice concerns due to the nature and/or location of the project.

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ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
General Land Use (residential, etc.) **RVC141021-07** Alta Verde Linea Homes	The proposed project consists of subdividing and developing approximately 7.21 acres of land for 14 single-family residences. Comment Period: 10/16/2014 - 11/14/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Palm Springs	Document screened - No further review conducted
General Land Use (residential, etc.) **SBC141003-03** Tentative Parcel Map 36732	The proposed project consists of a proposal for the land division of 17 lots totaling 277 acres within the existing Fairway Canyon Specific Plan Area for "finance & conveyance" purposes solely. It's based on the currently approved and implemented Oak Valley SCPGA Environmental Impact Report, Specific Plan, and Underlying Tract Map 31462. Comment Period: 9/30/2014 - 10/21/2014 Public Hearing: N/A	Community Notice	City of Beaumont	Document screened - No further review conducted
General Land Use (residential, etc.) **SBC141009-05** Tentative Parcel Map SUBTPM19528	The proposed project consists of a subdivision of a parcel of 58,745 square feet into two lots within the Very Low Residential District, Etiwanda Specific Plan. The project includes the construction of a circular driveway within one of the parcels that will be created by the subdivision. Comment Period: 10/13/2014 - 11/12/2014 Public Hearing: N/A	Draft Negative Declaration	City of Rancho Cucamonga	Document reviewed - No comments sent
General Land Use (residential, etc.) **SBC141010-04** PL14-0187 (Tentative Tract Map 18957)	The proposed project consists of subdividing 17.68 acres into 84 lots for future single-family residential development. Comment Period: N/A Public Hearing: 10/20/2014	Notice of a Public Hearing	City of Chino	No review conducted - No comments sent
General Land Use (residential, etc.) **SBC141010-05** Fairfield Ranch Commons	The proposed project consists of the development of the Fairfield Ranch Commons, which consists of 346 very high density residential apartment units on 14.73 acres and a 326,641 square-foot industrial business park on 17.37 acres. Comment Period: 10/10/2014 - 11/10/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Chino Hills	Document under review as of 10/31/14
Plans and Regulations **LAC141017-04** Lincoln Specific Plan	The proposed project consists of demolishing approximately 406,261 square feet of existing building associate with the former Nelles facility and existing onsite commercial use; construction of approximately 750 dwelling units, approximately 208,350 square feet of commercial land uses, and 4.6 acres of open space and off-site infrastructure improvements including roadway improvements to Whittier Boulevard, Sorensen Avenue, and the extension of Elmer Avenue onto the Project site. Comment Period: 10/17/2014 - 12/1/2014 Public Hearing: N/A	Draft Environmental Impact Report	City of Whittier	Document under review as of 10/31/14

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Plans and Regulations **ORC141014-06** General Plan Amendment 00616969-PGA, and Municipal Code Amendment 00617535-PZC to Update Population Generation Factors	The proposed project consists of a General Plan Amendment and City Municipal Code amendment to update population generation characteristics for consistency with 2010 Census population and housing figures. Comment Period: 10/14/2014 - 10/30/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Irvine	Document screened - No further review conducted
Plans and Regulations **RVC141017-03** Terracina Specific Plan and related General Plan Amendment No. 2012-03, Zone Change No. 2012-05, Vesting Tentative Tract Map 36557, and Vesting Tentative Tract Map 36577 for financing purposes	The proposed project consists of a residential development, with approximately 76.5 acres of residential, 22 acres of open space, 22.5 acres of roadways, 1.6 acres of park, and 28.20 acres of graded slopes and basins. Comment Period: 10/16/2014 - 11/17/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Lake Elsinore	Document screened - No further review conducted
Plans and Regulations **RVC141021-02** Belle Terre Specific Plan Project	The proposed project consists of a Specific Plan that would allow for the development of up to 1,326 residential units and open space and/or recreational features. Comment Period: N/A Public Hearing: N/A	Response to Comments	County of Riverside	Document screened - No further review conducted
Plans and Regulations **RVC141021-10** Specific Plan No. 382, GPA No. 1113, GPA No. 1013, GPA No. 1014 and CZ No. 7775	The proposed project consists of a Specific Plan that consists of a 342.3 acre residential community of up to 1,282 homes. Comment Period: N/A Public Hearing: 11/5/2014	Notice of a Public Hearing	County of Riverside	Document screened - No further review conducted

- Project has potential environmental justice concerns due to the nature and/or location of the project.

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ATTACHMENT A
INCOMING CEQA DOCUMENTS LOG
OCTOBER 1, 2014 TO OCTOBER 31, 2014

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Plans and Regulations				
SBC141001-02 Yucaipa General Plan Update	The proposed project consists of an update to the City of Yucaipa General Plan. The Plan involves the reorganization of the Current General Plan into the following six required and one optional element: the Land Use Element; Circulation Element; Open Space and Recreation Element; Conservation Element; Safety Element; Noise Element; and Economic Development Element. Build-out of the General Plan Update would allow for up to 77,328 people, 30,077 residential units, 28,380 households, 9,581,104 square feet of non-residential uses, and 18,488 jobs. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopyucaipagp.pdf Comment Period: 10/1/2014 - 10/31/2014 Public Hearing: N/A	Notice of Preparation	City of Yucaipa	SCAQMD staff commented 10/8/2014

TOTAL DOCUMENTS RECEIVED AND REVIEWED THIS REPORTING PERIOD: 99

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT B*
ONGOING ACTIVE PROJECTS FOR WHICH SCAQMD HAS OR IS CONTINUING TO CONDUCT A CEQA REVIEW

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Warehouse & Distribution Centers **SBC140923-04** Citrus Commerce Park	The proposed project consists of developing the Citrus Commerce Industrial Park (Near Term Development Site), a warehouse (Long Term Development Site) , and a park site on a 77.56 acre site. The proposed project may include the ultimate development of four logistics warehouse buildings for a total of 2,171,449 square feet of high cube warehouse/distribution. The Near Term Development Site applications also include a Design Review Application to construct three warehouse buildings (Building 1: 634,843 square feet, Building 2: 1,1038,499 square feet, and Building 3: 209,892 square feet), and Tentative Parcel Map to merge approximately 77.57 acres into three parcels. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/deircitrus.pdf Comment Period: 9/19/2014 - 11/3/2014 Public Hearing: 10/7/2014	Notice of Availability of a Draft Environmental Impact Report	City of Fontana	SCAQMD staff commented 10/31/2014
Warehouse & Distribution Centers **SBC140926-01** Auto Plaza at Fairway Warehouse	The proposed project consists of an approximately 178,980 square-foot industrial warehouse and parking, a Major Variance to allow the reduction of required parking spaces from 203 to 112 spaces on an 8.34-acre site. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndautoplaza-.pdf Comment Period: 9/25/2014 - 10/14/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Colton	SCAQMD staff commented 10/1/2014
Industrial and Commercial **LAC140916-04** International Auto Crafters	The proposed project consists of constructing a new commercial building on 1.37 acres on the northeast corner of Haun Road and New Hub Drive. The 17,007 square-foot automotive body shop will be located on the western portion of the project site with the entrance facing Haun Road. The building consists of various sections of an automotive body shop and two floors of office spaces, 1,300 square feet proposed on the first floor and 950 square feet proposed on the second floor. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/mndautocrafterFB22E35E5E25.pdf Comment Period: 9/16/2014 - 10/8/2014 Public Hearing: 10/8/2014	Notice of Availability of a Draft Mitigated Negative Declaration	City of Menifee	SCAQMD staff commented 10/1/2014
Waste and Water-related **LAC140917-01** Draft Cleanup Work Plan for Public Review and Comments - Exide Technologies	The proposed project consists of a draft Interim Measures Work Plan for the removal of lead contaminated soils in residential yards located in portions of Boyle Heights, East Los Angeles and Maywood. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dtscexide.pdf Comment Period: 9/16/2014 - 10/20/2014 Public Hearing: N/A	Community Notice	Department of Toxic Substances Control	SCAQMD staff commented 10/17/2014

Sorted by Comment Status, followed by Land Use, then County, then date received.

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT B
ONGOING ACTIVE PROJECTS FOR WHICH SCAQMD HAS OR IS CONTINUING TO CONDUCT A CEQA REVIEW

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
General Land Use (residential, etc.) **LAC140925-01** ENV-2013-1931/ 728, 732, 738, 744 and 748 N. Ganymede Dr.; Northeast Los Angeles	The proposed project consists of constructing five, single-family dwellings with an attached two-car garage on five lots. The project will require a Haul Route Permit from the Department of Building and Safety for the export of 3,145 cubic yards of dirt. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmnd732-748nganymeade.pdf Comment Period: 9/25/2014 - 10/27/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/9/2014
General Land Use (residential, etc.) **LAC140925-12** ENV-2014-1119/ 7128 N. Amigo Avenue; Reseda-West Van Nuys	The proposed project consists of a request for the development of a new 71-unit residential apartment building on an approximately 24,546 square-foot lot. The project will require the demolition of three single-family houses and two detached garage structures and the removal of trees. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmnd7128namigo.pdf Comment Period: 9/25/2014 - 10/15/2014 Public Hearing: N/A	Notice of Availability of a Draft Mitigated Negative Declaration	City of Los Angeles	SCAQMD staff commented 10/9/2014
General Land Use (residential, etc.) **LAC140930-06** Arcadia 17 Residential Condominium Project at 132, 136, and 142 Las Tunas Drive	The proposed project consists of the demolition of an existing auto repair shop, restaurant, and tattoo parlor to accommodate a residential-condominium development comprised of 17, three-story, townhouse-style units. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/dmndarcadia17resid.pdf Comment Period: 9/25/2014 - 10/14/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Arcadia	SCAQMD staff commented 10/9/2014
General Land Use (residential, etc.) **RVC140923-03** General Plan Amendment GPA-013-159, Zone Change ZC-013-160, and Tentative Tract Map TTM-014-300 (TTM 36659)	The proposed project consists of implementing a residential and open space development on an approximate 8.87-acre site. The project would consist of a General Plan Amendment to develop a 52 single-family residential lot. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/mndttm36659.pdf Comment Period: 9/17/2014 - 10/7/2014 Public Hearing: N/A	Draft Mitigated Negative Declaration	City of Murrieta	SCAQMD staff commented 10/7/2014
General Land Use (residential, etc.) **RVC140925-15** Alta Verde Linea Homes	The proposed project consists of subdividing and developing 14 single-family residences on a 7.21 acre site. The 14 residential lots will range in size from 15,834 to 24,005 square feet. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/nopaltadoc.pdf Comment Period: 9/25/2014 - 10/25/2014 Public Hearing: N/A	Notice of Preparation	City of Palm Springs	SCAQMD staff commented 10/1/2014

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT B
ONGOING ACTIVE PROJECTS FOR WHICH SCAQMD HAS OR IS CONTINUING TO CONDUCT A CEQA REVIEW

SCAQMD LOG-IN NUMBER PROJECT TITLE	PROJECT DESCRIPTION	TYPE OF DOC.	LEAD AGENCY	COMMENT STATUS
Plans and Regulations				
LAC140911-01 Montebello Hills Specific Plan	The proposed project consists of developing 1,200 residential dwelling units on approximately 173.6 acres of the project site; 314.6 acres dedicated for Open Space with a series of pedestrian walkways and trails; a 5.5-acre public park and a 1.5-acre private community center constructed for on-site residents. http://www.aqmd.gov/docs/default-source/ceqa/comment-letters/2014/october/deirmontebello.pdf Comment Period: 9/12/2014 - 10/27/2014 Public Hearing: 11/5/2014	Notice of Availability of a Draft Mitigated Negative Declaration	City of Montebello	SCAQMD staff commented 10/24/2014

TOTAL NUMBER OF REQUESTS TO SCAQMD FOR DOCUMENT REVIEW THIS REPORTING PERIOD: 99
TOTAL NUMBER OF COMMENT LETTERS SENT OUT THIS REPORTING PERIOD: 31
TOTAL NUMBER OF DOCUMENTS REVIEWED, BUT NO COMMENTS WERE SENT: 11
TOTAL NUMBER OF DOCUMENTS CURRENTLY UNDER REVIEW: 23
TOTAL NUMBER OF DOCUMENTS THAT DID NOT REQUIRE COMMENTS: 3
TOTAL NUMBER OF DOCUMENTS THAT WERE NOT REVIEWED: 1
TOTAL NUMBER OF DOCUMENTS THAT WERE SCREENED WITHOUT ADDITIONAL REVIEW: 40

- Project has potential environmental justice concerns due to the nature and/or location of the project.

Comment letters can be accessed at: http://www.aqmd.gov/home/regulations/ceqa/commenting-agency

ATTACHMENT C
ACTIVE SCAQMD LEAD AGENCY PROJECTS
THROUGH OCTOBER 31, 2014

PROJECT DESCRIPTION	PROPONENT	TYPE OF DOCUMENT	STATUS	CONSULTANT
Operators of the Ultramar Wilmington Refinery are proposing to construct and install a 49 MW cogeneration unit to reduce the refinery's reliance on electricity from the Los Angeles Department of Water and Power and produce steam to meet internal needs. No other refinery modifications are proposed.	Ultramar Wilmington Refinery	Negative Declaration	Staff revised responses to the 3 comment letters received on Draft ND and consultant is providing edited responses and finalizing the Draft ND. Responses to CEQA comments made on permit notice comment letter have been prepared and included in the Final ND that was certified on October 10, 2014.	Environmental Audit, Inc.
The Phillips 66 (formerly ConocoPhillips) Los Angeles Refinery Ultra Low Sulfur Diesel project was originally proposed to comply with federal state and SCAQMD requirements to limit the sulfur content of diesel fuels. Litigation against the CEQA document was filed. Ultimately, the California Supreme Court concluded that the SCAQMD had used an inappropriate baseline and directed the SCAQMD to prepare an EIR, even though the project has been built and has been in operation since 2006. The purpose of this CEQA document is to comply with the Supreme Court's direction to prepare an EIR.	Phillips 66 (formerly ConocoPhillips), Los Angeles Refinery	Environmental Impact Report	The Notice of Preparation was circulated for a 30-day public comment period on March 26, 2012. The comment period ended on April 26, 2012. The consultant submitted the administrative Draft EIR to SCAQMD in late July 2013. SCAQMD reviewed the Draft EIR and released for a 45-day public review and comment period on September 30, 2014.	Environmental Audit, Inc.
The Phillips 66 Los Angeles Refinery operators are proposing to install one new 615,000-barrel crude oil storage tank with a geodesic dome to accommodate larger marine vessels delivering crude oil. The proposed project also includes increasing the throughput (i.e., frequency of filling and emptying tank) on two existing tanks and adding geodesic domes to these tanks, installing one new 14,000-barrel water draw surge tank and installing one new electrical power substation.	Phillips 66 Los Angeles Refinery Carson Plant	Negative Declaration	The Draft ND was released for a 30-day public review and comment period beginning on September 10, 2013 and ending on October 9, 2013. Three comment letters were received. SCAQMD reviewed the responses to the comment letters and the consultant is making edits to the responses and finalizing the Draft ND.	Environmental Audit, Inc.
Tesoro Refinery proposes to integrate the Tesoro Wilmington Operations with the Tesoro Carson Operations (former BP Refinery). The proposed project also includes modifications of storage tanks at both facilities, new interconnecting pipelines, and new electrical connections. In addition, Carson's Liquid Gas Rail Unloading facilities will be modified. The proposed project will be designed to comply with the federally mandated Tier 3 gasoline specifications and with State and local regulations mandating emission reductions.	Tesoro Refining and Marketing Company Los Angeles Refinery	EIR	A previous Draft ND was withdrawn in order for this project to be analyzed in a new CEQA document that also addresses the upcoming Tesoro-BP Refinery Integration Project. An NOP-IS has been prepared for the integration project and released for a 30-day public review and comment period on September 10, 2014 closing on October 10, 2014. 86 comment letters were received.	Environmental Audit, Inc.

ATTACHMENT C
ACTIVE SCAQMD LEAD AGENCY PROJECTS
THROUGH OCTOBER 31, 2014

PROJECT DESCRIPTION	PROPONENT	TYPE OF DOCUMENT	STATUS	CONSULTANT
Operators of the KinderMorgan Lomita Terminal are proposing to deliver crude oil by expanding their rail facility.	KinderMorgan Lomita Terminal	To Be Determined	The consultants are preparing emission estimates to determine the type of CEQA document to be prepared.	SABS Consulting and TRC
Operators of the Petro Diamond Marine Terminal are proposing to increase the number of ship calls delivering ethanol.	Petro Diamond	To Be Determined	The consultant has prepared a Draft Negative Declaration. SCAQMD staff is currently reviewing the Draft Negative Declaration to determine if it is the appropriate type of CEQA document for the project.	SABS Consulting
Quemetco is proposing an increase in daily furnace feed rate.	Quemetco	To Be Determined	Initial Study under review by SCAQMD staff.	Trinity Consultants
Chevron is proposing modifications to its Product Reliability and Optimization (PRO) Project and has applied for a change of permit conditions to reduce NOx emissions and fired duty operating conditions of the Tail Gas Unit.	Chevron	Addendum	Under staff review and edits provided to the consultant. Chevron currently conducting BACT review for equipment.	Environmental Audit, Inc.
Signal Hill Petroleum is proposing to upgrade the existing natural gas processing plant and enhance their vapor recovery system. No new combustion equipment will be installed.	Signal Hill Petroleum Gas Plant	Subsequent Mitigated Negative Declaration	The consultant has prepared an SMND and SCAQMD Staff is currently reviewing.	RBF Consulting
Exide Technologies is proposing a project to reduce toxic emissions of arsenic, benzene and 1,3-butadiene to comply with SCAQMD Rules and Regulations.	Exide Technologies	Mitigated Negative Declaration	SCAQMD Staff has prepared a Draft MND that was released for a 30-day public review and comment period on October 16, 2014.	Environ
Breitburn Operating LP is proposing to upgrade their fluid handling systems to facilitate an increase in the amount of produced water that can be treated at the site in Sante Fe Springs.	Breitburn Operating LP	Environmental Impact Report	Staff is reviewing an NOP/IS prepared by the consultant.	Environ

COMMUNITIES FOR A BETTER ENVIRONMENT

January 2, 2015

Via Electronic Mail

South Coast Air Quality Management District
21865 Coley Drive,
Diamond Bar, CA 91765

Re: Community Demand to Immediately Withdraw December 12, 2014 Notice of Determination for the Final Negative Declaration for Phillips 66 Los Angeles Refinery Carson Plant Crude Oil Storage Capacity Project – SCH. No. 2013091029.

Dear Ms. Radlein, Mr. Krause and Ms. Tyagi,

I am writing to you today on behalf of Communities for a Better Environment ("CBE") and its members who reside in Wilmington, to call your attention to an issue that deserves your careful consideration, and immediate action. As you are aware, based on your review of formal comments submitted to the South Coast Air Quality Management District ("District") as well as other forms of communication including correspondence via email, and in-person and phone conversations with District staff including each of your individual offices, CBE is concerned about the District's minimal and often cursory review of new, proposed refinery modification, crude transport and storage projects that affect CBE's members and other, similarly situated residents of environmental justice communities.

The District's December 12, 2014 decision to finalize the Phillips 66 Carson Project Negative Declaration demonstrates a complete disregard for the District's duty to protect particularly vulnerable South Coast Air Basin residents from the impacts of transporting, receiving, storing and processing dangerous crudes from known domestic and Canadian sources. By finalizing its minimal environmental review document, the District has failed to conduct the level of environmental review required to assess and mitigate the Phillips 66 Carson Project's impacts, and has additionally failed to take reasonable and necessary steps to protect the public by providing adequate notice of its decision. Indeed by issuing its notice of determination on December 12, a mere week before the 2014 Christmas holiday, and by neglecting to ensure actual prompt notice to commenters and known interested advocates, the District appears to be intentionally undercutting the public's legal right to challenge its decision making regarding this project. As such, and for the additional reasons briefly described herein, we demand that you immediately withdraw the District's December 12, 2014 final determination approving the Phillips 66 Carson Project Negative Declaration.

1. The District's decision to finalize the Phillips 66 Carson Project Negative Declaration ignores cumulative impacts from other projects and environmental justice concerns.

Currently there are 3 refinery projects being proposed in Wilmington and the adjacent City of Carson, as well as additional project-related permit applications at various stages of review by the District. All 3 projects directly impact many of CBE's members and other residents living *directly on the fenceline* of the refineries at which they are being proposed.

These 3 projects include:

1) The Phillips 66 Carson Plant Crude Oil Storage Capacity Project ("Phillips 66 Carson Project") for which the District issued a Notice of Intent to Adopt a Negative Declaration, pursuant to the California Environmental Quality Act ("CEQA") on September 10, 2013 and recently issued its Notice of Determination for a Final, unchanged Negative Declaration, dated December 12, 2014;
2) The Phillips 66 Wilmington Ultra Low Sulfur Diesel Project, for which the District issued a Draft Environmental Impact Report on September 26, 2014; and,
3) The Tesoro-BP Refinery Integration Project, for which the District issued a notice of preparation of a Draft Environmental Impact Report on September 9, 2014 (and for which the District is also reviewing two Title V permit revisions and renewals--for the Tesoro Marine Terminal 2 and the Tesoro Hynes Terminal in Long Beach).

Wilmington and the cities of Carson and Long Beach rank among the State's top most pollution-burdened and vulnerable areas.[1] Residents of these communities live with the day-to-day impacts of various forms of heavy industry, oil extraction and refining operations, port and other goods-movement and transport activities, including significant levels of air pollution caused by diesel truck and railroad transport.[2] As such, these residents rely heavily on the oversight of agencies like the District to ensure that permitting decisions regarding additional, highly polluting industrial projects are made wisely, with careful attention to the true range of environmental and health impacts resulting from each individual project alone, and in the context of existing

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[1] Wilmington, Carson and parts of Long Beach 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. (*See* http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?&extent={"xmin":-13166567.802417224,"ymin":4001409.3038827637,"xmax":13157213.82108084,"ymax":4005584.676552836,"spatialReference":{"wkid":102100}}&appid=a4a95185c71f4817bf03aeae25923695 (last accessed, Dec. 23, 2014).
[2] *See Id.*

cumulatively considerable burdens.[3]

Despite the existing burden on this area, the District is conducting an impermissibly superficial level of environmental review for projects directly impacting some of the region's most vulnerable neighborhoods. While this problem is in large part a result of inaccurate and often misleading project descriptions contained in the applications submitted by refinery operators, the District is responsible for ensuring that CEQA and other air quality and human health protective requirements are met before it moves forward in issuing or approving any permits or other project-related approvals, including approvals of environmental review documents and permit renewals or revisions.[4]

The District's December 12, 2014 Notice of Determination regarding the Phillips 66 Carson Project Negative Declaration demonstrates the District's refusal to conduct the level of environmental review required to assess and mitigate the full range of the project's impacts, including its cumulatively considerable impacts, and its failure to take reasonable and necessary steps to protect the public by providing adequate notice of its decisions.

2. ***The District intentionally refused to ensure that advocates and known interested parties were given adequate notice of its December 12, 2014 decision.***

After over a year of silence regarding the status of the Phillips 66 Carson Project's Draft Negative Declaration, the District decided to finalize its unchanged draft document a week before the Christmas holiday. Despite the fact that CBE submitted extensive comments on the draft Negative Declaration on October 9, 2013, and despite CBE's persistent requests for information concerning this, and other similar projects, the District further failed to ensure that CBE

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[3] *See, Laurel Heights Improvement Assn. v. Regents of Univ. of California* (1988) 47 Cal.3d 376, at 394 (holding that the significant cumulative effects of a project must be considered in an EIR, and specifying that such required cumulative effects should encompass "past, present, and reasonably anticipated future projects.); *see also*, CEQA Guidelines, § 15064 (h)(1) (also requiring preparation of an EIR, where cumulative impacts are considerable, and providing that "[w]hen assessing whether a cumulative effect requires an EIR, the lead agency shall consider whether the cumulative impact is significant and … An EIR must be prepared if [a] Project's incremental effect, though individually limited, is cumulatively considerable[,]" meaning that "incremental effects of an individual project are significant when viewed in connection with the effects of past projects … other current projects, and … probable future projects"), and §15355 ("'Cumulative impacts' refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts"); *see also*, Clean Air Act, Declaration of Purpose, at 42 U.S.C. § 7401(b)(1)-(3), (c)(providing that the purpose of the Act is to enhance the quality of the Nation's air resources so as to promote the public health and welfare; and to encourage and assist the development and operation of regional air pollution prevention and control programs to do the same.).

[4] *See* Cal. Pub. Res Code § 21082.2(a) (requiring the lead agency to determine whether a project may have a significant effect on the environment based on substantial evidence in light of the whole record.); *see also Citizens Assoc. For Sensible Development of Bishop Area v. County of Inyo* (1985) 172 Cal.App.3d 151("The lead agency must consider the whole of an action, not simply its constituent parts, when determining whether it will have a significant environmental effect."); and *see* CEQA Guidelines § 5041(setting forth the Lead Agency's Authority to mitigate negative environmental impacts, and providing that "A lead agency for a project has authority to require feasible changes in any or all activities involved in the project in order to substantially lessen or avoid significant effects on the Environment.").

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advocates, staff and members were given actual, prompt notice of its final determination.[5] Rather than emailing notice of its decision to commenters, as has been its common practice, the District merely posted its decision on its website and sent the same notice in the mail which arrived over a week after the District's determination had been made.[6]

3. ***The District's decision to finalize the Phillips 66 Carson Project Negative Declaration amounts to a quiet, rubber stamp approval for the increased transport, storage and processing of dangerous domestic and Canadian derived crudes.***

The District's responses to comments concerning the Phillips 66 Carson Project further expose the agency's cavalier approach to the serious human health and environmental concerns raised by commenters to that project, as well as other, similar projects. In its responses, the District admits that Phillips 66 not only plans to bring down heavy tar sands and dangerous bakken crudes in the foreseeable future, but it also concedes that the refinery has been processing the same crude types, without disclosure to the public for some, unknown period of time.[7] Publicly exposing this fact in the same act in which it rubber stamps its minimal review of the Project's potential impacts presents a clear dereliction of the agency's duty to protect the environment and to minimize air emissions in the South Coast.[8]

4. ***Because the District has refused to conduct the level of environmental review required under state law, and has deliberately refused to provide actual notice of its decision, its December 12, 2014 final determination must be withdrawn.***

In sum, while the District has provided responses to comments regarding CBE's concerns with Phillips 66's explicit plans to refine dangerous new crudes, it has failed to address the resultant impacts that such refining will have on some of the South Coast's most vulnerable residents. The District's decision to refuse to ensure that such residents and their advocates were notified before the peak of the winter holiday season, further demonstrates its disregard for those bearing the brunt of the impacts from such a project, and its desire to fast-track its permit

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[5] In addition to requesting information and updates in the enclosed letters, CBE staff attorneys have called District staff offices to leave messages, or have had phone conversations with individual District staff members including Barbara Radlein, Veera Tyagi, Mike Krause and other staff on at least the following dates: February 14, March 20, July 18, August 8, August 20, September 11, October 7 2014, and November 5, 2014.

[6] The District sent notice to CBE by mail, postmarked four days after the determination--on December 16, 2014--which arrived at CBE's offices three days later (Friday afternoon, December 19), and was received by one of the intended recipients on December 22, ten days after the District certified the Final Negative Declaration.

[7] *See e.g*., Notice of Determination – Final Negative Declaration Phillips 66, Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project – SCH No. 2013091029, at Appendix F, Response 2-9, F-42.

[8] *See City of Redlands v. County of San Bernardino* (2002) 96 Cal.App.4th 398, 405 (holding that an (EIR) must be prepared under CEQA whenever substantial evidence in the record supports a "fair argument that a proposed project will have a significant effect on the environment" (citations omitted).); *see also,* CEQA Guidelines §15384, and 42 U.S.C. § 7401(b)(1)-(3), (c), *supra*; *and see* Cal. Health and Safety Code § 40001(b) (District rules and regulations may, and at the request of the state board provide for the prevention and abatement of air pollution episodes which, at intervals, cause discomfort or health risks to, or damage to the property of, a significant number of persons or class of persons.).

approvals in a manner that contravenes public input, and undercuts the public's legal rights to challenge the District's decision making.

For these reasons, and for the additional reasons expressed in CBE's comments on the above listed projects, as well as the additional, attached correspondence, we urgently request that you take immediate steps to withdraw the December 12, 2014 Notice of Determination for the Final Negative Declaration for the Phillips 66 Carson Project.

Sincerely,

/s
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The Proposed Negative Declaration by SCAQMD for the Tesoro Pipeline from its Long Beach Marine Terminal to New Wilmington Refinery Storage Tanks is Missing Major Expansion Plan Descriptions and Requires a Full EIR

Comments of Julia E. May,
Senior Scientist, CBE
June 10, 2014

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I. Introduction

This report evaluates the Tesoro Storage Tank Replacement and Modification Project (described hereafter as the "Project") in Wilmington and finds that a Negative Declaration (ND) published by the South Coast Air Quality Management District should not be adopted, because the Project has broad implications for changing operations at the refinery, marine operations, in integration of the Wilmington with the Carson refinery, among other changes. These changes have significant impacts that need to be evaluated through a full Environmental Impact Report (EIR).

II. The Project Description is flawed – the Pipeline & Storage Tank Negative Declaration is contradicted by Tesoro's Published Broader Plans

A. Project description

The ND[1] describes the Project as merely a way to offload products faster, to speed getting ships out of harbor, unrelated to other transportation and refinery operations. For example, it states:

> *Description of Nature, Purpose, and Beneficiaries of Project: The Tesoro Refining & Marketing Company LLC (Tesoro) is proposing a storage tank replacement and modification project at its Los Angeles Refinery – Wilmington Operations* ***to increase the amount of crude oil that can be stored, and to increase the efficiency of the crude oil deliveries from ships****. . . .*

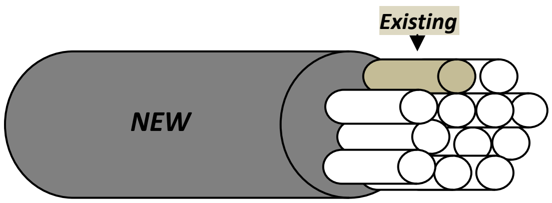
The ND describes very large storage expansion (440,000 bbls per day increase for two tanks, plus increased throughput of 150,000 bbls/month for one tank), and changes in materials stored:

	Current size	Proposed size	Permitted Materials Stored	Proposed Materials Stored
Tank 80035 - Fixed to Internal floating roof	80,000 bbl	300,000 bbl	Petroleum materials including crude oil, hydrocracking unit (HCU) feedstock (a light gas oil); currently primarily stores HCU feedstock (ND p. 1-1)	Light & heavy crude oils of varying vapor pressures up to 11psi, light gas oils (such as HCU feedstock &FCCU Feedstock), & heavy gas oils, but ND also states these will primarily store crude oil
Tank 80036 - Fixed to Internal floating roof	80,000 bbl	300,000 bbl		
Tank 80038 Fixed roof w/out vapor recovery, connect to vapor recovery	80,000 bbl	No size change	Petroleum distillate w/true vapor pressure <0.5psi such as crude oil & heavy gas oils, currently primarily stores vacuum gas oil (heavy)	Change types of materials stored to also include light gas oil
Tank 80079 Internal floating roof tank	80,000 bbl	Same size, but increased throughput from 350,000 to 500,000 bbls/month	Petroleum distillate w/true vapor pressure <7.6psi such as crude oil, heavy gas oils, light gas oils, diesel fuel, primarily stores crude oil	No change in types of materials permitted to be stored

[1] Negative Declaration at p. 2-1, and Notice of Intent to Adopt a Draft Negative Declaration, Tesoro Storage Tank Replacement and Modification Project, at 2nd page.

No specific baseline data is provided on the current materials actually stored in the tanks.

The description also proposes greatly increased pipe sizing (from a 12-inch diameter pipe, to a 42-inch pipe) for delivery of crude oil and other materials from the Marine Terminal to these storage tanks. The volume of material that can be delivered through a pipe is dependent on cross-sectional area; the 42-inch pipe would allow a delivery increase of over 12 times the volume currently able to be delivered.[2]



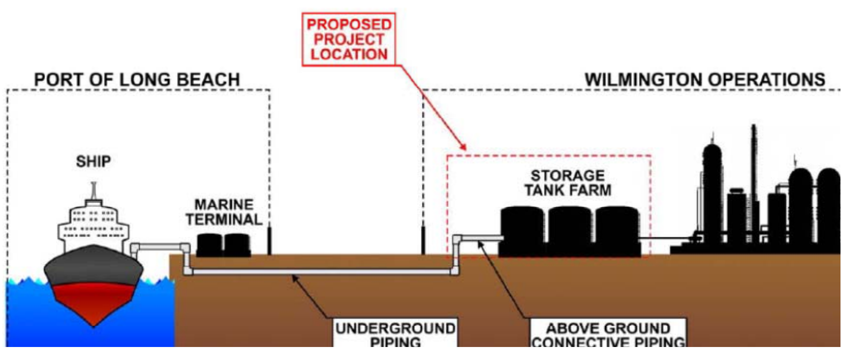
← Over 12 twelve-inch pipes would fit into one 42-inch pipe, so the volume of crude oil & other petroleum liquids that can be offloaded through the new pipe is over 12 times higher than the existing pipe

The description incorrectly concludes there will be no significant impacts, and counter to Tesoro's public statements documented later, there will be no changes in materials delivered:

> *No changes to the type of materials delivered to the Wilmington Operations are proposed. The following environmental topic areas were identified as having the potential to be affected by the proposed project: air quality and greenhouse gas emissions; energy; geology and soils; hazards and hazardous materials; hydrology and water quality; noise; solid and hazardous waste; and transportation and traffic. However, the analysis of these environmental topic areas in the Draft Negative Declaration (ND) concludes that the proposed project would not generate any significant adverse environmental impacts.*

But the changes described above have the potential for major operational debottlenecking and changes in materials (e.g. crude oil) delivered, with associated impacts described below. Furthermore, Tesoro has publicly announced such changes outside of the ND process.

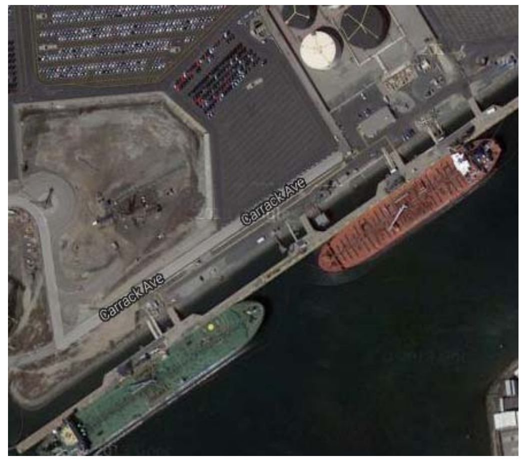
The following graphic of the project was provided in the ND (at p. 1-10):



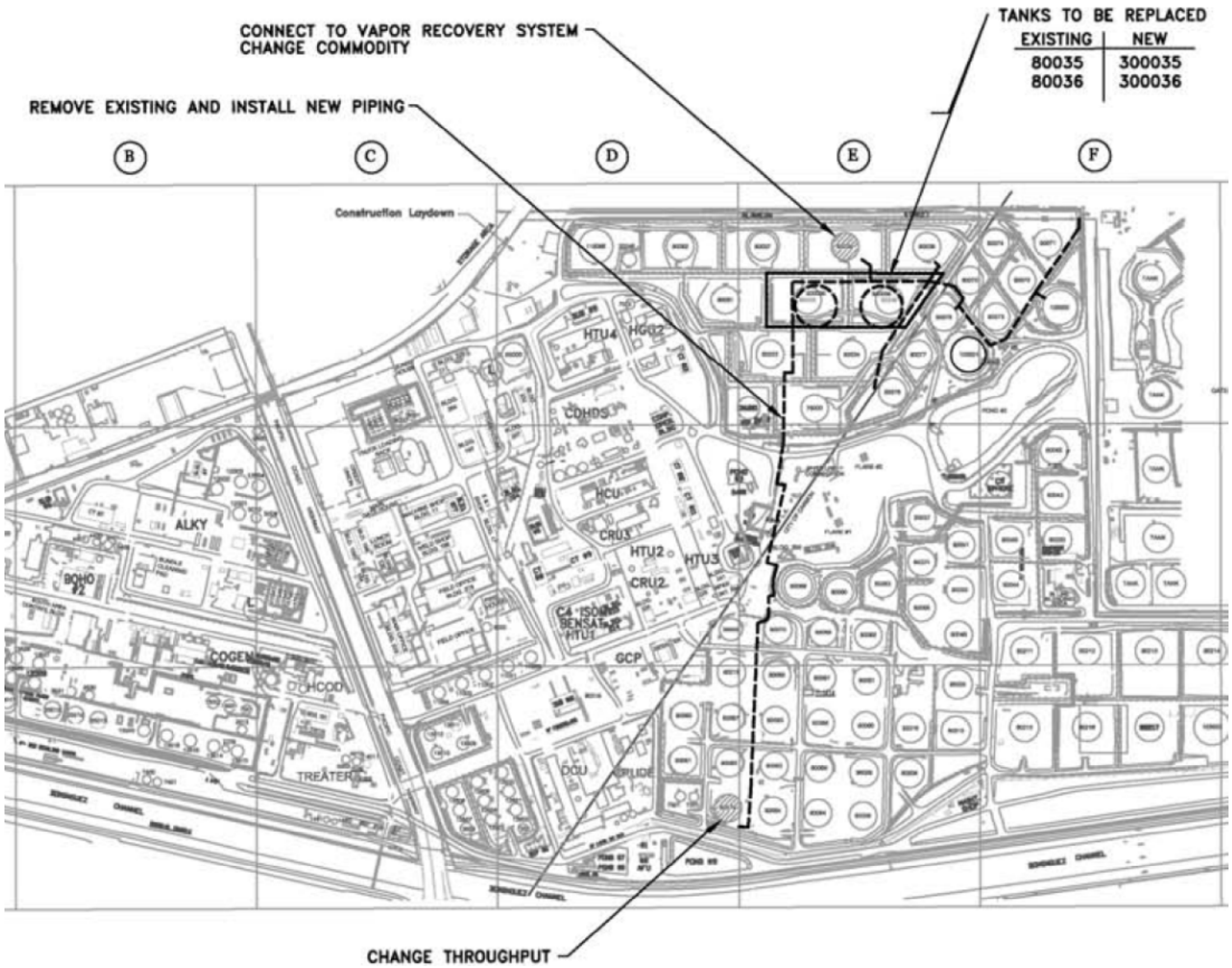
[2] A 12 inch diameter = 6 inch radius, a 42 inch diameter = 21 inch radius. Volume of material delivered depends on the pipe cross-section area. The cross-sections of the two pipes' areas are: For 12 inch pipe the area = Πr^2 = 3.14 x (6*6) sq inches, or 3.14 x 36; For 42 inch pipe the area = 3.14 x (21*21) or 3.14 x 441. Thus the 42 inch pipe cross-section area is larger than the 12 inch pipe by a factor of 441/36, or 12.25.

The difference in the physical locations of the Marine Loading terminal and the refinery shown in the graphic above and the satellite images below illustrates that there will be a large increase in petroleum materials piped in the range of a mile from the terminal to the refinery. This in itself increases the risk of spills, especially during earthquakes. The ND states that there will not be a physical change at the Marine Terminal itself, but it fails to evaluate the major increase in volume of materials that will be present in the pipes at any one moment.

The Pier B Tesoro facility (Port of Long Beach, 820 Carrack Ave, Long Beach 90813, Facility ID 172878, Tesoro Logistics Operations LLC) was identified by the SCAQMD by telephone as the marine loading facility involved in the Project, although Tesoro Logistics now owns three marine loading facilities in Los Angeles. Different magnifications are inserted below, including Pier B, and the Wilmington refinery (on the order of a mile away):



The map below, excerpted from the ND (at p. 1-6), depicts the long path of the new pipeline across the refinery to the new refinery tanks. (This map has been rotated 90 degrees to make wording readable.) It also shows that the pipe goes *beyond* the new tanks, to the corner of the Wilmington property.



B. **Tesoro has published plans to increase throughput, yields, transport alternative crude types by rail to Washington then by ship to Long Beach, and to integrate the Wilmington refinery with the adjacent Carson refinery**

Both industry literature and Tesoro statements reveal that Tesoro has been planning the following:

- Increased throughput at its California refineries (including its Wilmington and Carson complex),
- Increased product yield,
- Integration of the Wilmington and Carson refineries,
- Changes in crude oil type delivery and processed in favor of cheaper crudes (“advantaged” or “discount” crudes which can have negative impacts when transported and refined),

- Use of rail to transport crude to Tesoro's Vancouver Washington shipyard, and then by ship to California refineries (from Bakken oil fields in North Dakota but also potentially from Canadian tar sands fields),
- Use of its facilities by Third parties and for export, and
- Increased coking operations.

The alternative crude would be offloaded from marine vessels, sent through the greatly expanded pipeline described in the ND, and stored in the massively expanded storage tanks proposed. Importantly, the Wilmington and Carson refinery operations share a fenceline.

These publicly acknowledged projects are clearly related to the storage tank expansion, and demonstrate that the proposed Project goes far beyond simple ship offloading efficiency. Even if we had no knowledge of these plans, such storage expansion would have the *potential* to allow expanded activities at the refinery and the Marine Loading dock, and to change operations through integration with Tesoro's Carson refinery. These operations cannot be "piecemealed" from the storage project, and must be evaluated together through a full EIR.

1. Industry literature identified these plans

An example of an industry literature report on Tesoro plans is provided by Morningstar Inc. (a multinational, multi-billion dollar research and investment management firm[3]), which published the following analysis in July of 2013: [4]

> *Tesoro aims to* ***increase throughput*** *of domestic crude over the next few years*
>
> *Tesoro has embarked on a multiyear plan to improve its profitability, including increasing spending to support larger income improvement projects. The most significant of those, including capacity expansions and rail facilities, aim to take advantage of domestic crude discounts. . . .*
>
> ***We think, however, the biggest area of opportunity for Tesoro to improve its profitability is by increasing processing of discount crude, particularly in its primary market of California,*** *where operating conditions remain challenging. The company is highly leveraged to developments within the state and that will only increase with its proposed acquisition of BP's BP* ***Carson*** *refinery. Operating in California can be advantageous because West Coast margins typically fetch a premium given the state's relative isolation from outside sources of refined product and specialized gasoline blends. . . .*
>
> ***The increased availability of discount crude bolsters the potential for the Carson acquisition despite the increased exposure to California.*** *Specifically, Tesoro can* ***dramatically improve the performance of Carson by optimizing its crude slate with light crude from the Bakken.*** *Also, on its face the deal looks like a winner for Tesoro given the relatively attractive valuation of the refinery and the collection of associated*

[3] http://corporate.morningstar.com/US/asp/subject.aspx?xmlfile=177.xml
[4] 7/24/2013 http://analysisreport.morningstar.com/stock/archive?t=TSO&region=USA&culture=en-US&productcode=MLE&docId=604033 (emphasis added throughout quotes)

midstream assets that can be dropped down to Tesoro Logistics TLLP. ***Tesoro should gain further advantages from integrating Carson with the Wilmington refinery.*** *. . .*

The addition of Carson and its integration with Tesoro's Wilmington refinery *should lower costs and better position the company to deal with increasing environmental regulation. . . .* [Emphasis added throughout and below]

Discount crudes generally have negative impacts as described below. For example, Canadian tar sands crude oil is very heavy, with high sulfur, requiring more intensive refining, and Bakken crude oil from the Dakotas has high paraffinic content (wax) and is explosive. These require specialized handling or more intensive refining with environmental and safety impacts (described later). The article also identifies the potential for Tesoro to import either Bakken or Canadian heavy tar sands crude.

Increasing throughput of light and heavy discount crude from the Mid-Continent and Canada via rail will likely benefit Tesoro more, though. *To this end, Tesoro recently entered an agreement to develop a 120 mb/d crude by rail and marine facility in Washington.* ***The facility should be operational in 2014 and affords Tesoro the flexibility to send light or heavy crude to its California refineries.*** *Tesoro's California refineries should realize higher margins and improved returns through lower feedstock costs and* ***improved yields*** *while expending little capital.*

(Note that this project was updated and expanded from the 120,000 barrel/day figure to 360,000 barrel/day, to be completed in 2015.[5]) The Morningstar webpage also explained in July of 2013 why oil companies are incentivized to change operations to accommodate such cheap crude oil:

Success in the refining business is primarily a function of the difference in the amount the refiner pays for oil and the amount at which it sells the refined product. *As such, the short- and long-term risks are dependent on movements in the prices of crude oil and gasoline or diesel. Supply interruptions or increased demand that drive up oil prices, as well as demand destruction or economic slowdown that depress gas prices, are the primary risks.* ***Additionally, the recent strong operating performance is attributable to wide crude differentials.***

Such crude differentials are available for both Bakken and Canadian tar sands crude. The costs can fluctuate, so many refiners, including Tesoro, are looking at both these sources depending on the most current price fluctuations and logistics. Tesoro has evaluated both Bakken and Canadian crude sources, and both these sources are booming compared to existing Tesoro crude sources, which have been dropping.[6]

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[5] Tesoro Savage, Application for Site Certification Agreement (Vancouver Application), Vol. 1, August 29, 2013, http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf

[6] California's Oil Refiners Double Crude-by-Rail Volumes (1), Lynn Doan May 02, 2014, Bloomberg Business Week, ["*U.S. West Coast refiners including Tesoro Corp. (TSO:US) and Valero Energy Corp. (VLO:US) are developing projects to bring in more oil by rail from reserves across the middle of the U.S. and Canada to displace more expensive supplies. Crude production in PADD 5, which includes California and Alaska, has dropped every year since 2002 while drillers are extracting record volumes from shale in states including North Dakota and*

The Morningstar report also identifies other refinery processes such as vacuum distillation, increased coking, increased product export, and increased yields, as related to the Project. For instance, the analysis identifies a recent Wilmington refinery vacuum distillation unit project allowing increased coking. The vacuum distillation tower was also reported in Bloomberg news in late 2012, with further allusions to Tesoro's plans to integrate Wilmington and Carson operations, which could result in shutdown of Tesoro's fluid catalytic cracking unit (FCC), unit. This further stresses the changes to overall refinery balancing and design which can occur as a result of the changes in crude oil which would be brought in as a result of the ND's pipeline and storage Project.[7]

Heavy, bottom of the barrel portions of crude oil are a much higher proportion in heavier crudes, which result in production of petroleum coke in higher quantities, which the storage project would also enable. The evaluation states:

> . . . . *To address these challenges, Tesoro is focusing on improving yields and lowering operating costs at its facilities* ***while increasing export volumes*** *to higher value markets.* ***To improve yields, Tesoro replaced a vacuum distillation unit at its Wilmington facility, which should allow it to upgrade petroleum coke to clean products.*** . . .
>
> *In the Pacific Northwest, Tesoro's two refineries, which account for almost 30% of total capacity, are at a disadvantage because of their lack of cokers, resulting in poor yields and large amounts of fuel oil. However, Tesoro's recently completed project to rail upward of 50,000 bpd of discount, light Bakken crude to its Washington refinery, should lead to reduced dependence on waterborne crude and improved margins.*

Increased coking means increased emissions from coking operations. Increased exports have the potential to increase emissions due to refining, storing, and loading products for export. Increased yields of individual product units within the refinery have different characteristics, and must be evaluated specifically, rather than looking at the overall crude oil throughput, since different units have different chemical use and different emissions, which can be impacted even without an increase of crude throughput. All of these are related operations with potentially major impacts not evaluated in the ND.

The Morningstar literature identified the lack of cokers at Tesoro's Pacific Northwest refineries as increasing the need for taking advantage of available coking facilities in California refineries:

> ***Tesoro's refining capacity is concentrated in California. . . .***
>
> *Second, it has invested in rail facilities to move 50 mb/d of Bakken crude west to its Anacortes, Wash., refinery, which has resulted in improved yield and margins.* ***Finally, we expect the imbalance between light and heavy crude in the Mid-Continent will create an opportunity and***

Texas."] http://www.businessweek.com/news/2014-05-02/california-doubles-oil-by-rail-volumes-as-canadian-imports-grow and
Tesoro Seeks More Canadian Crude Oil for Its West Coast Refineries, February 7, 2013, Wall Street Journal, http://online.wsj.com/article/BT-CO-20130207-710688.html

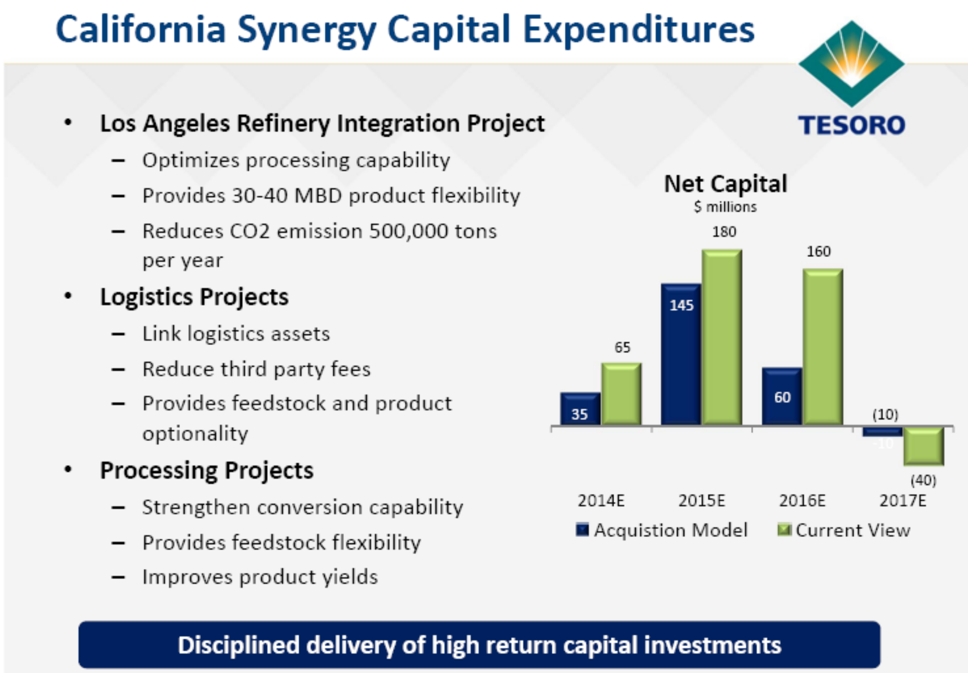
[7] Tesoro Wilmington Refinery Begins Operating New Vacuum Tower, Aaron Clark and Dan Murtaugh - Nov 26, 2012, http://www.bloomberg.com/news/print/2012-11-26/tesoro-wilmington-refinery-begins-operating-new-vacuum-tower.html

economic incentive to rail both types of crude to its three California refineries, increasing their throughput of cost-advantaged crude. *In fact, Tesoro already has plans in place to do so. . . .*

2. Tesoro also published these plans

Tesoro has confirmed these industry findings. For example, a February 2014 Tesoro slideshow[8] on Tesoro's"Presentations" webpage states *"Los Angeles acquisition [BP Carson and terminals and coking] transforms our capabilities,"* providing flexibility in yield, access to "advantaged" crude oil, integrated logistics infrastructure, etc. (Slide 7).

Another slide below (12) identifies the "Los Angeles Refinery Integration Project" (integrating Carson and Wilmington refineries) as optimizing processing capability and "product flexibility":



This is followed by a slide describing Tesoro's "Advantaged" feedstock opportunity, ***"Extending the advantaged crude oil to the West Coast,"*** **and changing the Los Angeles operations crude oil feedstock from 15% California Heavy crude to *"Potentially up to 50% California Heavy and Bakken"* crude oil (at Slide 13).**

The slideshow also evaluates the cost of crude by rail directly to West Coast refineries, including Los Angeles, in the following (slide 15), but also states that the cost of rail to the state of Washington, and then by ship to California, is "Competitive with direct rail cost to California" (at Slide 17). Slide 17 also finds that its Washington rail to ship project provides ***"Flexibility to deliver to all West Coast refineries."***

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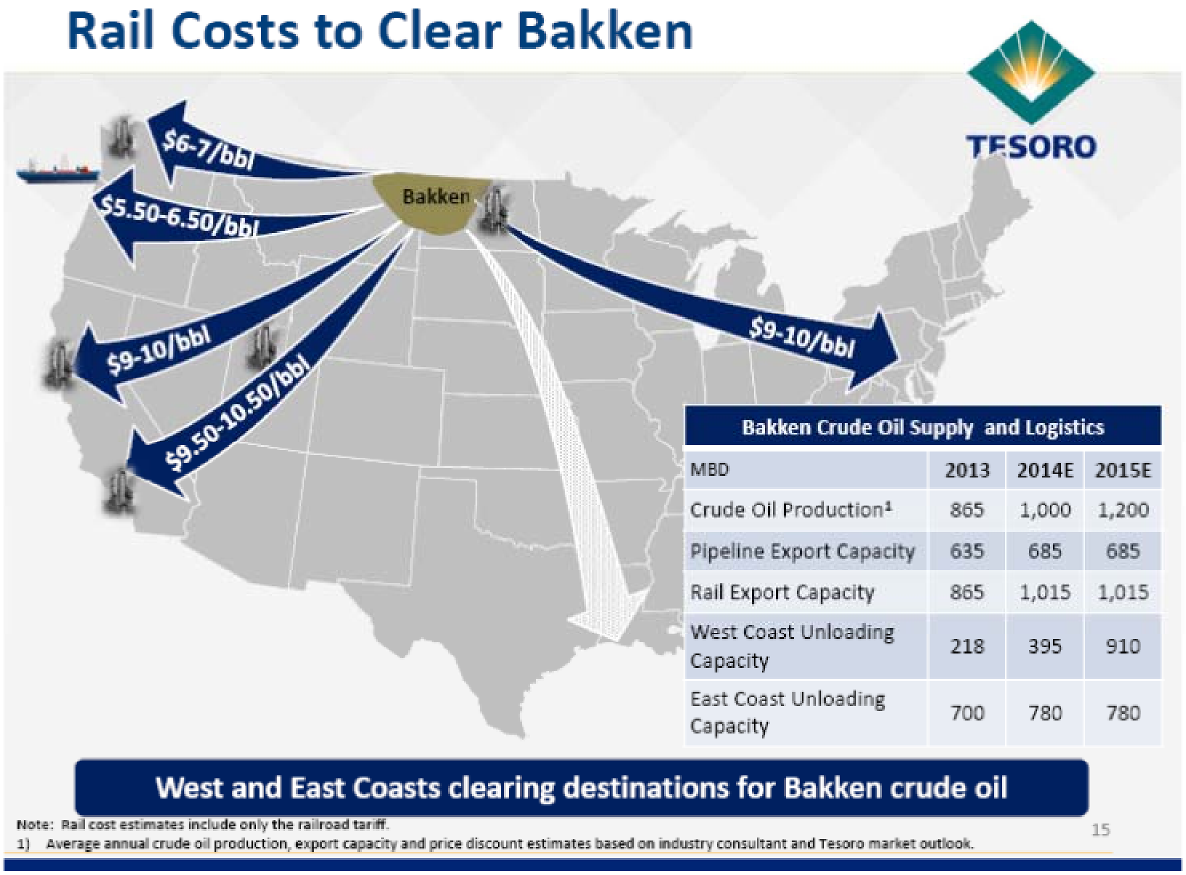
[8] Simmons Energy Conference, *Transformation through Distinctive Performance,* February 27, 2014, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations attached

Another key point on Slide 15 as shown below is the massive increase in "West Coast Unloading capacity" from 218 barrels per day (bpd) in 2013, to 395 bpd estimated in 2014, to 910 bpd estimated in 2015. California is the largest share of West Coast Tesoro capacity, and Los Angeles is the largest share of Tesoro California capacity.



Crude oil unloading capacity is the subject of this ND, by unloading crude oil from ship to the expanded pipeline, to the expanded storage tankage. **As a result, it is clear that Tesoro's West Coast plans for bringing Bakken crude into LA will require the increased unloading and storage identified in the Negative Declaration.**

Another very similar version of this slideshow presented a month earlier by Tesoro (January 2014)[9] elucidates further that "Terminaling, Transportation, and Storage" will "Consolidate Tesoro volumes in Southern California distribution system" (and identifies additional impacts in Southern California). Storage capacity is an essential requirement for terminal, transportation, and refining operations. None of the required evaluation of relationships of storage capacity changes to these other processes have been evaluated in the negative declaration, as they should have been.

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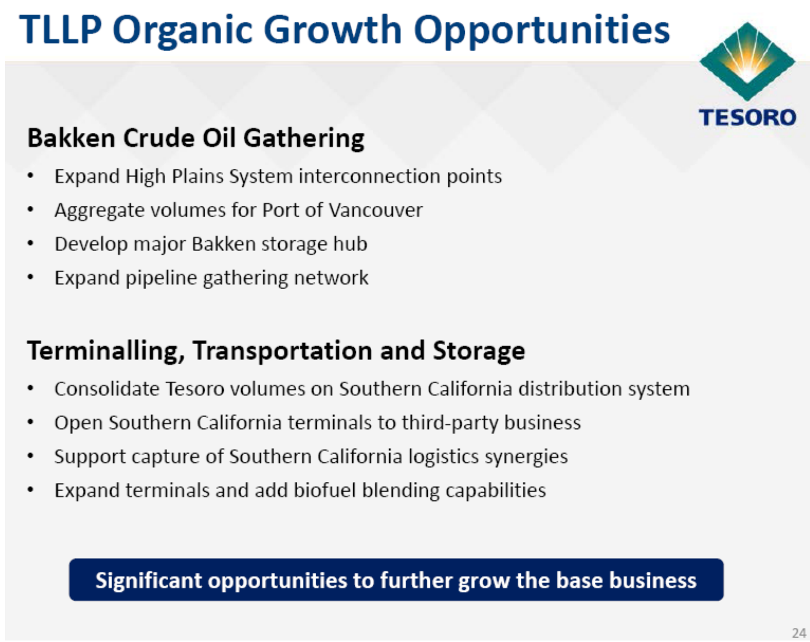
[9] 2014 Deutsche Bank Energy Conference, January 9, 2014, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-presentations (Slide 24), attached



Slide 34 in this second presentation also mentions a plan to decommission the Wilmington refinery's FCC (Fluid Catalytic Cracker) unit. Again, such a change should be identified as part of the whole broad project, either directly, or as part of a cumulative impacts evaluation.

The Slides and previous reports above show that Tesoro has considered different options for transporting crude from North Dakota and Canada to the Los Angeles complex, including rail transport directly to California (despite the ND's dismissal of rail as potentially connected to this Project). Tesoro has lately settled on the rail to Washington and ship to Long Beach option. However, if conditions change (for example, if the Washington hub does not proceed due to public opposition), Tesoro could instead take advanatage of the new Tankage's proximity to the nearby railline that traverses both its LA refineries. For example, the new Tesoro pipeline continues past the new storage tanks, and ends next to the railway that transects the refinery, as discussed later.

III. Potential impacts of the Project are large

A. Changes in crude oil feedstock facilitated by the Project have significant impacts

1. Waxy Bakken crude oil requires special handling and creates problems of transfer in both marine vessels and refinery storage tanks and requires chemical dispersants

An article from Hydrocarbon Processing -- *Innovative Solutions for Processing Shale Oils*[10] -- identifies problems in processing oils such as Bakken shale, due to high variability in crude qualities, waxy buildup (paraffinic content), etc. This article specifically identified transfer to refinery tankage as problematic:

> ***The paraffin content of the shale oils is impacting all transportation systems.*** *Wax deposits have been found to coat the walls of railroad tank cars, barges and trucks. Waxy deposits in pipelines regularly require pigging to maintain full throughput. Bakken shale oil is typically transported in railcar, although pipeline expansion projects are in progress to accommodate the long-term need. These railcars require regular steaming and cleaning for reuse. Similar deposits are being encountered in trucks being used for shale oil transportation.* ***The wax deposits also create problems in transferring the shale oils to refinery tankage. Fig. 4*** *shows samples of deposited wax collected from pigged pipelines*[11] *in shale oil service. [emphasis added]*

The article provided photos (entitled "waxy deposits removed from shale oil buildup") which graphically depict the more obvious problems with Bakken crude:

The article also identified multiple chemical dispersants used to mitigate these problems not only during transportation, but also within refineries where these shale oils are processed.

> *To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously.*

These chemicals must be identified in a full EIR in order to assess the impacts of their use. The article also found that steam cleaning is used to remove such deposits from railcars. Such activities should be identified and associated impacts evaluated. Impacts within the refinery must also be evaluated for safety risks.

2. Bakken crude oil also causes fouling of preheaters, heat exchangers, and furnaces, refinery corrosion, and can shutdown refinery units

[10] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, attached http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html

[11] A "pig" is launched through a iline until it reaches a rece

The Hydrocarbon Processing article found that asphaltene destabilization can occur when blending shale oil with heavier crudes. This is precisely the kind of blending that could occur due to the Project, since Tesoro has stated it plans to change the crude slate in California from 15% California Heavy crude to *"Potentially up to 50% California Heavy and Bakken"* (see earlier in this comment).

These problems result in fouling of the cold preheat train, fouling of hot preheat exchangers and furnaces, problems in transportation, storage, refinery corrosion, and crude unit shutdowns. These oils are also extracted through fracturing, which have additional and major impacts on water, air, and the global climate. The article finds:

> *The refining of shale oil (also known as tight oil) extracted through fracturing from fields such as Eagle Ford, Utica and* ***Bakken*** *has become prevalent in many areas of the US. Although these oils are appealing as refinery feedstocks due to their availability and low cost, processing can be more difficult.*
>
> ***The quality of the shale oils is highly variable. These oils can be high in solids with high melting point waxes.*** *The light paraffinic nature of shale oils can lead to asphaltene destabilization when blended with heavier crudes. These compositional factors have resulted in cold preheat train fouling, desalter upsets, and fouling of hot preheat exchangers and furnaces. Problems in transportation and storage, finished-product quality, as well as refinery corrosion, have also been reported. Operational issues have led to cases of reduced throughput and crude unit shutdowns. The problems encountered with shale oil processing and possible prediction and control strategies will be presented.*
>
> [Emphasis added throughout and below]

The article found use of shale oils was particularly problematic when blended with heavy crudes, which is admittedly planned by Tesoro for its California refinery operations. This blending can cause agglomeration of large molecules onto surfaces inside refinery units which can crack and leave coke-like deposits if the surfaces are hot.[12] Coke deposits lead to poor operation and can cause shut down of units before planned maintenance periods. All these problems require special handling and planning at the refinery. In addition, the article found shale oils to be highly variable in certain characteristics including for example, its solids content, and others. The article states:

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

[12] Coke is a petroleum product that is mostly the carbon leftover after making gasoline from crude oil. Coke is a fuel, and similar to coal, as an energy source that results in high GHG and criteria pollutant emissions, and significant heavy metal content.

3. Bakken crude is volatile and explosive and these characteristics were not evaluated in the ND

Unfortunately, Bakken crude oil has been fatally demonstrated as very volatile and explosive, as in the case of the tragic explosions at Lac Megantic in Canada, and in other instances.

The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration issued a safety alert regarding the transport of this type of crude oil in January of 2014, finding that **whether it was transported in railcar or other mode of transport, it represents unique hazards of explosion, fire, and corrosivity,** requiring additional testing, handling, and public information for first responders.[13] Entrained gases require additional testing.

> ***The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert to notify the general public, emergency responders and shippers and carriers that recent derailments and resulting fires indicate that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.***
>
> *Based upon preliminary inspections conducted after recent rail derailments in North Dakota, Alabama and Lac-Megantic, Quebec involving Bakken crude oil, PHMSA is reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. Proper characterization will identify properties that could affect the integrity of the packaging or present additional hazards, such as corrosivity, sulfur content, and dissolved gas content. These characteristics may also affect classification.*
>
> ***PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, whether the shipment is in a cargo tank, rail tank car or other mode of ransportation.*** *Emergency responders should remember that light sweet crude oil, such as that coming from the Bakken region,is typically assigned a packing group I or II. The PGs mean that the material's flashpoint is below 73 degrees Fahrenheit and, for packing group I materials, the boiling point is below 95 degrees Fahrenheit.* ***This means the materials pose significant fire risk if released from the package in an accident.***
>
> *. . . Based on initial field observations, PHMSA expanded the scope of lab testing to include other factors that affect proper characterization and classification such as* ***Reid Vapor Pressure, corrosivity, hydrogen sulfide content and composition/concentration of the entrained gases*** *in the material. The results of this expanded testing will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any unique hazards of the materials will enable offerors, carriers, first responders, as well as PHMSA and FRA to identify any appropriate mitigating measures that need to be taken to ensure the continued safe transportation of these materials.*

This is a major problem with the Project, at the Marine Terminal in Long Beach, in the expanded pipeline to the refinery, in the storage tanks at the refinery, and in the refinery where it will be

[13] The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, January 2, 2014, http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_111F295A99DD05D9B698AE8968F7C1742DC70000/filename/1_2_14%20Rail_Safety_Alert.pdf , attached

used. It was a major failure of the ND to ignore these impacts, which even without the other impacts, would require an EIR.

4. Bakken crude refining can also increase levels of acutely hazardous and corrosive Hydrogen Sulfide in the refinery

The Hydrocarbon Processing article also identified increased levels of extremely hazardous hydrogen sulfide (H2S) gas as a problem associated with shale oil. Furthermore, when scavenging agents are used to reduce H2S presence, these can cause corrosion and form solid deposits inside processing units. The article states:

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

Hydrogen sulfide is deadly, corrosive, causes odor complaints when released, and its increase in the refinery certainly requires specific evaluation that was absent in the ND.

A report by Bakkenshale.com found:[14]

> *Is the Bakken producing higher volumes of H2S? That's the question you have to ask yourself when you see pipelines implementing H2S standards for the first time.*
>
> *On May 8, Enbridge submitted an emergency application to the Federal Energy Regulation Commission (FERC) asking to amend its conditions of carriage to 5 ppm of H2S or less. If accepted, Enbridge would have the right to reject crude with higher levels of H2S. . . .*
>
> ***Enbridge acted after it found concentrations of 1,200 ppm in a crude tank at its Berthold Terminal. 20 ppm is the limit allowed by OHSA and an average of 10 ppm of exposure is all that is allowed over an 8-hour work day.***
>
> *Both Plains Marketing and Murex Petroleum objected to the FERC application, but it looks as if they solved their differences when Enbridge notified FERC it wasn't planning an outright ban on crude with higher H2S concentrations. The two companies weren't against the change, but were afraid they couldn't comply in the time frame planned.*

Thus hazardous and corrosive sulfur compounds can either be part of the crude characteristic, but also can be transported with otherwise low sulfur crude oil. The Chemical Safety Board report also identified that H2S was a particularly aggressive corrosive agent.[15] These issues must be

[14] May 30, 2013, http://bakkenshale.com/pipeline-midstream-news/bakken-producing-sour-gas-h2s-problem-in-north-dakota/
[15] *Id.* at p. 33

evaluated through a full EIR to prevent severe safety risks associated with crude slate changes.

The problem of sulfur corrosion increasing accident risk was unfortunately born out at Chevron Richmond in California last August, when a major explosion barely avoided killing 19 workers, but did send 15,000 neighbors to the hospital, after a huge black plume traveling many miles through the Bay Area resulted from the crude unit explosion, which burned for many hours.

Steelworkers testified at the U.S. Chemical Safety Board hearing on the Chevron explosion that such sulfur corrosion is a statewide problem at California oil refineries.[16] The Chemical Safety Board found the Richmond accident was caused by sulfur corrosion that Chevron had been aware of, and had repeatedly ignored, and the report showed that sulfur content had increased. The photos below show the heavy impact not only in Richmond, but across the San Francisco Bay Area due to this accident.

A discussion of corrosion issues at oil refineries due to increased sulfur content in crude oil, and other important related issues was provided in the attached report of Greg Karras on the Phillips 66 *Rodeo* refinery EIR.[17] Also refer to the previously cited report of Dr. Fox on impacts of use of "advantaged" crude are also in process.

These reports demonstrate in further detail the impacts of corrosion demonstrated by the US Chemical Safety Board, causing the massive explosion in August of 2012 in the Chevron Richmond refinery, pictured below. The U.S. Chemical Safety Board report is also available.[18] The significance of the air pollution impacts caused by the Chevron explosion are self-explanatory, in the photos below of the August 2012 explosion caused by the refinery corrosion.

[16] U.S. Chemical Safety Board transcript of public hearing on Chevron Richmond, CA August 2012 explosion and fire, page 225, http://www.csb.gov/assets/1/19/0503CSB-Meeting.pdf
[17] Expert Report of Greg Karras, CBE, 4 September 2013, Regarding the Phillips 66 Company Propane Recovery Project Draft Environmental Impact Report released in June 2013 by the Contra Costa County Department of Conservation and Development
[18] Interim Investigation Report, Chevron Richmond Refinery Fire, (which as adopted at the July public hearing) available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf

5. Another "advantaged" crude oil from Canadian Tar Sands that Tesoro plans to import also causes major impacts

As previously identified, Tesoro plans to bring cost advantaged crude oil to Los Angeles, both light and heavy, including heavy Canadian tar sands crude. Canadian tar sands crude is even cheaper than Bakken, as discussed by Bloomberg about Tesoro's plans to use the cost advantage of Canadian heavy crude in California.

> ***U.S. West Coast refiners including Tesoro Corp. (TSO) and Valero Energy Corp. (VLO) are developing projects to bring in more oil by rail from reserves across the middle of the U.S. and Canada to displace more expensive supplies.*** *Crude production in PADD 5, which includes California and Alaska, has dropped every year since 2002 while drillers are extracting record volumes from shale in states including North Dakota and Texas.*
>
> *The surging flows of domestic oil to California "reflect a continuing improvement in crude-by-rail receiving facilities here," David Hackett, president of Stillwater Associates, an energy consultant, said by phone from Irvine, California.*
>
> ***Lower Costs***
> *Crude from North Dakota and Canada trades at a discount to Alaska North Slope oil, which rose 36 cents to $107.78 a barrel at 9:09 a.m., data compiled by Bloomberg show.* ***Western Canada Select, a heavy, sour blend, gained 36 cents to $82.88.*** *North Dakota's Bakken crude also gained 36 cents to $95.28. It costs $9 to $10.50 a barrel to send North Dakota's Bakken oil by rail to California, according to Tesoro, the West Coast's largest refiner.*

Of course, tar sands crude oil causes major environmental damage during its mining in Canada, as described by the World Resources Institute, which rather mildly states the severe impacts:[19] "*The local and regional environmental impacts of heavy oil and tar sands production can include: significant water consumption, massive earth moving and ecosystem disturbance, increased criteria and other air pollution, and release of heavy metals and toxic materials."*

But the ND must account for the local Los Angeles region, and global impacts. Canadian tar sands are even heavier than most heavy conventional crudes (higher carbon content, requiring additional energy to process and increasing emissions) and have higher sulfur content. Contaminants must be removed during refining, which increases hazardous materials present within the refinery and can lead to dangerous corrosion within refinery operations units. These

[19] http://www.wri.org/publication/content/10339

also increase energy needed for refining, resulting in higher greenhouse gas and smog-precursor emissions. The corrosion hazard is increased due to the higher sulfur content, increasing refinery accident risk identified by the US Chemical Safety Board in the last section.

The ND failed to evaluate the obvious increases in desulfurization processes within the refinery due to higher sulfur content, as well as additional cracking, coking, and additional use of hydrogen, all of which require more energy and increase criteria and toxic pollutant emissions. This is a major and obvious area of impacts that was completely ignored in the ND, especially without any baselines provided.

An Oil & Gas Journal article *Special Report: Refiners processing heavy crudes can experience crude distillation problems* (Oil and Gas Journal),[20] also identified the need for additional desalting and temperature controls in order to process unconventional crude oils. This and the other articles identified many problems with processing unconventional crudes, emphasizing that it is not just *volume* of crude throughput that determines environmental impacts, but also the characteristics or *quality* of the crude oils. The Oil and Gas Journal article (*Refiners processing heavy crudes can experience crude distillation problems)* also identified a number of differences in the content of unconventional crudes (such as tar sands and others):

> *Heavy crudes have much higher microcarbon residue (MCR), asphaltenes, and metals. As mandated refinery gasoline and diesel pool sulfur specifications take effect, minimizing cat feed hydrotreater (CFHT) feed contaminants becomes more important. In some cases, vanadium in the CFHT feed has increased from less than 1 ppm to 5-10 ppm with heavy Venezuelan crudes.*[1] ***High feed-stream contaminants can reduce run length to less than half the planned turnaround interval.*** *Optimizing the atmospheric column flash-zone and wash section, and the vacuum unit design can reduce CFHT feed vanadium by 30-40%. . . .*
>
> *Heavy crudes have higher viscosities, some have higher salt content, several have high naphthenic acid content, and they are all more difficult to distill than lighter crude blends. Some upgrader crudes also have lower thermal stability than conventional crudes and higher fouling tendencies due to the increased likelihood of asphaltene precipitation. . . .*
>
> *High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability.*

A complete inventory and evaluation of differences in the crude oils to be processed at the refinery due to the Project changes needs to be evaluated for environmental impacts.

Additional emissions during the transport, piping, tank loading, and in refinery operation from volatile diluents used with expanded tar sands crude oils have not been identified, and should be, with emissions quantified. Diluents can include volatile and toxic compounds such as BTEX

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[20] Oil and Gas Journal, Special Report: Refiners processing heavy crudes can experience crude distillation problems, 11/18/2002, available at http://www.ogj.com/articles/print/volume-100/issue-47/special-report/special-report-refiners-processing-heavy-crudes-can-experience-crude-distillation-problems.html , attached

VOCs (Benzene, Toluene, Ethylbenzene, and Xylene).[21] In addition to the highly reactive ozone-precursor quality of such diluents, they need to be identified and evaluated as toxic air contaminants, due to carcinogencity and other health impacts, as well as any potentially explosive compounds.

6. The Project Description failed to provide baseline data on the current crude oil slate, to compare it to the "advantaged" crudes the Project allows, and to identify the potentially significant impacts of such changes

The ND did not provide baseline information about the crude oil slate. This is a major omission especially given Tesoro's public acknowledgement of the key nature of its planned switch to cost-advantaged crude oils such as Bakken crude (or Canadian tar sands). The ND assumes that if general *types* of crude oil and products remain the same, then the Project cannot cause changes with significant impacts. But this is demonstrably false – changes in the crude slate can cause major impacts regardless of existing AQMD permit conditions, even if volumes don't change. Tesoro should have provided this baseline information.

Through outside sources we can find some very basic information about the recent crude slate at Tesoro's Wilmington and Carson refineries:

- The Alaska Business Monthly stated that the Carson refinery formerly owned by BP has recently (2012) processed significant levels of Alaska North Slope crude (ANS).[22]

  "According to Chuck Coulson, BP's manager for midstream operations, BP refines "virtually" all of its Alaska crude at its two West Coast refineries: Cherry Point in Puget Sound and Carson refinery in L.A. County. ***BP runs a mix of Alaska North Slope crude and crude from other countries at both facilities****.*

- The BP website stated in 2013 that the Carson facility processed **ANS, Middle Eastern, and West African crude**:[23]

  "It processes crude oil from Alaska's North Slope, the Middle East and West Africa."

- Tesoro's SEC report identified in California refineries:[24]
  "Our California refineries run a significant amount of ***South American heavy crude oil ("Oriente"), San Joaquin Valley Heavy ("SJVH") and light crude oil from Iraq ("Basrah"),*** *which continued to be priced at a discount to Brent throughout 2013."*

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[21] Comments of NRDC on the Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, July 1, 2013, on impacts of diluents and other important impacts related to the Valero Benicia crude by rail project in common with the Phillips 66 Los Angeles refinery complex, http://switchboard.nrdc.org/blogs/dbailey/NRDC%20comments%20letter%20on%20Notice%20of%20Intent%20to%20Adopt%20a%20Mitigated%20Negative%20Declaration%20for%20the%20Valero%20Crude%20by%20Rail%20Project.pdf
[22] Following North Slope Crude from the Ground to the Gas Station, May 2012 article, http://www.akbizmag.com/Alaska-Business-Monthly/May-2012/Following-North-Slope-Crude-From-the-ground-to-the-gas-station/?utm
[23] BP Completes Sale of Carson Refinery and Southwest U.S. Retail Assets to Tesoro Release date: 03 June 2013, http://www.bp.com/en/global/corporate/press/press-releases/bp-completes-sale-of-carson-refinery-and-southwest-u-s--retail-a.html
[24] http://biz.yahoo.com/e/140224/tso10-k.html

Tesoro's 2013 SEC report[25] also provides a general picture of Tesoro's crude slate in California from 2011 to 2013 (but not at the individual refineries):

> ***Our refineries process both heavy and light crude oil.*** *Light crude oil, when refined, produces a greater proportion of higher value transportation fuels such as gasoline, diesel and jet fuel, and as a result is typically more expensive than heavy crude oil. In contrast, heavy crude oil produces more low value byproducts and heavy residual oils. These lower value products can be upgraded to higher value products through additional, more complex and expensive refining processes. Throughput volumes by feedstock type and region are summarized below (in Mbpd):*

	2013		*2012*		*2011*	
California	*Volume*	*%*	*Volume*	*%*	*Volume*	*%*
Heavy crude	*178*	*42*	*151*	*62*	*156*	*65*
Light crude	*206*	*49*	*67*	*28*	*60*	*25*
Other feedstocks	*38*	*9*	*24*	*10*	*25*	*10*
Total	*422*	*100*	*242*	*100*	*241*	*100*

Tesoro's chart shows Heavy Crude feedstock lowering from 65 to 42%, with Light Crude increasing from 25 to 49%, and other unidentified feedstocks remaining about the same. It appears that at least half of 2013 did not include the BP purchase, which increased the throughput greatly.

The US EIA (Energy Information Administration) provides data on foreign crude imports, but not on refineries' domestic crude use. The following table provides an example of US EIA Tesoro data for the month of March 2014. The ND should provide current baseline information from 2010 to the present, including both imported and domestic crude slate for each of the Wilmington and Carson refinery portions.

[25] Tesoro's US Securities and Exchange Commission (SEC), Annual 10-K report, for 2013, at p. 5, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=3&ved=0CDIQFjAC&url=http%3A%2F%2Fphx.corporate-ir.net%2FExternal.File%3Fitem%3DUGFyZW50SUQ9NTM1NDc5fENoaWxkSUQ9MjIzNTc3fFR5cGU9MQ%3D%3D%26t%3D1&ei=UuGUU7CZO8qOqAbW7ILgAg&usg=AFQjCNFro71tQanqMTIBnERVK-mEduvJPQ&sig2=-yTQ5qcuA3RSmO-yIIdOqQ&bvm=bv.68445247,d.b2k

US EIA Data, Tesoro Corp Crude Oil Imports, Port City: Los Angeles, CA, Port Code 2704, Reporting Period March 2014. Downloaded 6/8/2014 by Jmay, CBE, from US EIA Excel file at: http://www.eia.gov/petroleum/imports/companylevel/ Totals and weighted averages are added				
CNTRY_ E2NAME	**QUANTITY (thousands of bpd)**	**SULFUR**	**API GRAVITY**	**PCOMP_SNAM**
ANGOLA	230	0.4	25.6	CARSON
ANGOLA	321	0.45	25.6	CARSON
ANGOLA	342	0.42	25.6	CARSON
ANGOLA	502	0.45	25.7	CARSON
COLOMBIA	379	0.7	28.4	CARSON
IRAQ	150	2.59	32	CARSON
IRAQ	257	2	28.9	CARSON
IRAQ	294	2.58	32	CARSON
IRAQ	356	3.13	29.3	CARSON
IRAQ	693	3.08	29.3	CARSON
IRAQ	802	2.61	31.9	CARSON
TOTAL	4326			
CARSON	Weighted Average:	1.82	28.77	
CANADA	245	3.46	24.1	WILIMINGTON LOS ANGELES
ECUADOR	396	1.95	19.9	WILIMINGTON LOS ANGELES
TOTAL	4326			
WILMINGT	Weighted Average:	2.53	21.51	

The data above shows that out of crude imports, almost 38% of the Wilmington refinery in March was already from Canada, with a very high sulfur content – indicating that Wilmington is already importing substantial Canadian tar sands crude. However, the weighted average sulfur content for that month for *imports* of Tesoro was about 2.53% sulfur (for imports only, since the EIA data does not provide domestic crude use information by refinery), much lower than the Canadian crude (shown at 3.46%). Increasing the Canadian source further will increase the average sulfur content.

The Carson portion of the Los Angeles refinery complex on the other hand, had a much lower weighted sulfur average (1.82%), and lighter crude oil (API gravity is a reverse scale, so that higher gravity indicates lighter crude). The former BP Carson refinery is designed for a lighter feedstock compared to the Wilmington refinery. The location of the new storage tanks, with the proposed pipeline expansion through the refinery, and continuing to the corner of the Wilmington operation, could be used to source either the Wilmington OR the Carson operations.

Having a major increase in tankage and connection via rail to Washington and via ship to Long Beach, allows Tesoro to increase either lighter Bakken OR heavy Canadian tar sands, both "advantaged" crude oils, both with serious environmental impacts.

There is an array of public information available about the potential impacts at refineries using different crude oil slates. In one example, the International Council on Clean Transportation's 2013 Report: *Effects of Possible Changes in Crude Oil Slate on the U.S. Refining Sector's CO2 Emissions, Final Report*[26] found not only that refinery CO2 emissions varied considerably

[26] March 29, 2013, http://www.theicct.org/sites/default/files/publications/ICCT_Refinery_GHG_Study_Proj_Report_Apr2013.pdf

depending on the type of crude oil processed, but identified the changes in yields of refinery products. Further, an excerpt from this report shows that Bakken shale oil (generally considered on *average* a light and low sulfur crude oil), can vary in quality, and can be heavy,[27] so it should not be assumed that imported Bakken crude would always be lighter than the current slate.

	2011	Crude Slate							
Inputs & Outputs	Calib	Base	Ext. Heavy	Very Heavy	Heavy	Mid Expan	Import Indep	Light	Very Light
Inputs (K b/d)									
Crude Oil	14,712	14,314	14,383	14,664	14,540	14,327	14,354	14,131	14,057
C4s	234	170	246	170	170	170	170	170	170
NGL, Naphtha & Gas Blndstk.	209	302	302	302	302	302	302	302	302
Heavy Gas Oil & Resid	661	474	474	474	474	474	474	474	474
Purchased Energy									
Electricity (MM Kwh/d)	172	167	190	183	177	170	167	155	154
Natural Gas (K foeb/d)	612	642	783	715	703	665	664	631	636
Outputs (K b/d)[1]	**15,682**	**15,105**	**15,113**	**15,108**	**15,101**	**15,094**	**15,089**	**15,082**	**15,082**
Light Gases	583	542	550	545	538	531	526	519	519
Aromatics, Naphthas, & Av Gas	259	241	241	241	241	241	241	241	241
Hydrocarbon Gasoline	7,623	6,764	6,764	6,764	6,764	6,764	6,764	6,764	6,764
Jet Fuel	1,493	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
Diesel Fuel	4,471	4,946	4,946	4,946	4,946	4,946	4,946	4,946	4,946
Resid & Asphalt	895	715	715	715	715	715	715	715	715
All Other Liquids	358	332	332	332	332	332	332	332	332
Coke	590	690	1,015	1,109	940	731	692	456	361
Sulfur (K s tons/d)	20	19	23	29	26	20	21	13	12

The specific CO2 emissions in this study have been refuted by a peer reviewed CBE study published in Environmental Science and Technology[28] which showed that the greenhouse gas emissions impacts of heavy crude oil are much higher than shown in this oil industry-sponsored study.

The CBE paper documented that the impacts of crude oil density or API gravity (heaviness of crude oil) and sulfur content (which usually accompanies heavy crude) on greenhouse gas emissions strongly predicts high energy use at oil refineries. High energy use means high carbon dioxide emissions from this processing. This high energy intensity drove a 39% increase in greenhouse gas emissions across regions and years at oil refineries.

However, even the industry study showed in the chart above that crude quality impacts the volume of individual products *produced* by the refinery. This is also a common-sense conclusion – it is obvious that lighter crude oils produce higher volumes of gasoline, and that heavier crude oils produce more bottoms and more coking. These changes cause a multitude of environmental impacts that the District is well aware of. But the ND assumes contrary to these fundamental principles, that because throughput is expected not to change, and heat input is expected to be the same at the crude unit at the front end, that no changes will occur downstream in the refinery. This is plainly incorrect and must be re-assessed (in addition to the problem of lack of baselines in the ND).

[27] In the Table entitled *Exhibit 3: Composition of Alternative Crude Slates, by Crude Type* (K b/d), showed 720 thousand barrels per day of Bakken crude oil in the Heavy Crude designation column, 37th page

If light, low sulfur Alaska North Slope (ANS) crude oil, which is continually lowering in - production, is displaced with extremely heavy, high sulfur Canadian tar sands crude oil, clearly that would increase sulfur content in the refinery, increase corrosion hazard and potential impacts of H2S gas, and require additional energy to process the heavy crude.

If Bakken crude oil were to replace, for example, ANS at the Tesoro refineries, this may or may not be comparable to ANS crude *in gravity and sulfur content*. (since Bakken is acknowledged as extremely variable). However, even if the Bakken crude were light, its high paraffin content described above, can cause waxy, dangerous buildup in transport, in the refineries, can be accompanied by toxic diluents, and explosion hazards (a la Lac Megantic explosion in Canada).

If Bakken is mixed with heavy crudes, asphaltene destabilization, preheater fouling, desalter upsets, unwanted coking, etc., identified earlier in the Hydrocarbon Processing article, can occur. These impacts can cause dangerous shutdowns and accidents. The specific changes must be identified to provide an accurate Project Description, to enable a full evaluation of potential impacts.

If instead, which may be the most likely case, heavy Canadian Select would replace California heavy crude at the Wilmington facility, then sulfur content and API gravity goes up considerably, causing increased presence of H2S and increased energy use; while the Bakken imports would go to the Carson portion of the refinery complete, which is designed to handle lighter crude, but introducing the documented problems associated with Bakken characteristics that are not present in, for example, Alaskan crude.

Other impacts aside from CO2 emissions and energy use were also described in the International Council's report on impacts of varying crude slates. The table entitled Exhibit 11 inserted on the next page from the International Council report described above, identified varying refinery *product outputs* caused by varying *crude oil slate inputs*. In other words, the amount of gasoline, diesel, jet fuel, coke, sulfur, light gases, naphtha, resid, and aromatics produced at the refinery varied depending on the variation of crude oils into the refinery.

That means that the impacts associated with each of these different operations change with different crude oil inputs, and these impacts must be evaluated for the Tesoro project, after providing the baseline crude slate, and comparing it to the proposed potential changes in crude slate facilitated that the new Project allows. Some refinery processes involve light ends (which may for example have high benzene content, a known carcinogen), others involve heavy refinery components (which may for example be associated with higher particulate matter emissions, which increase death rates in the population). Others have high levels of odorous and hazardous sulfur compounds, or may increase fire or explosion risk. The pieces of the refinery are not interchangeable, and modifications to crude slate have impacts on the individual components of the refinery which should have been identified.

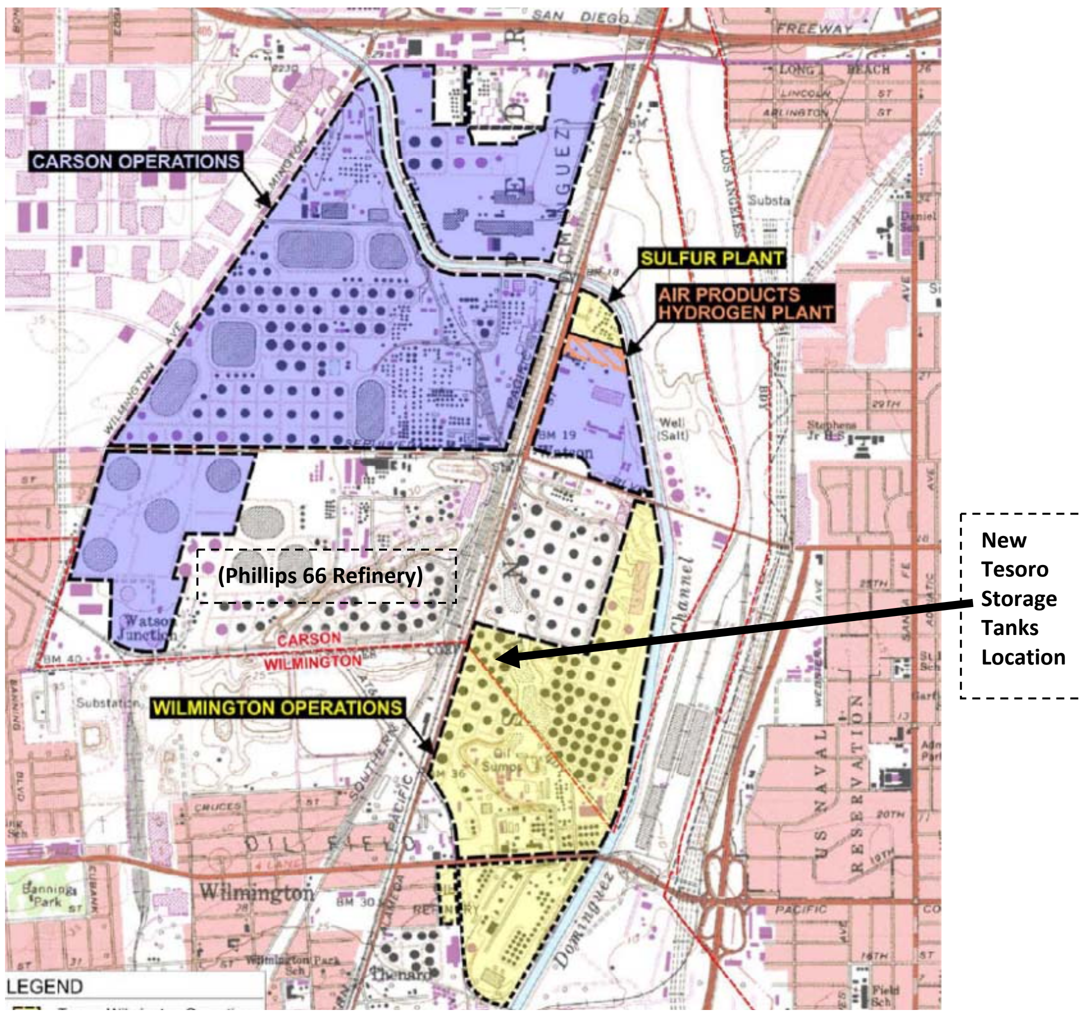
A report by Dr. Phyllis Fox on a crude by rail project to the Valero Benicia California refinery identified many impacts due to switches to "advantaged" crude oils, including increased metals, increased use of toxic BTEX compounds, and many other impacts in transportation and at the refinery due to use of changing crude slates.[29] All the issues identified in this report should be evaluated for the Tesoro ND.

CEQA provides requirements for clear project descriptions and potential impacts. Even if Tesoro has permits that allow variations in crude oil types, if those variations can cause significant impacts, they still must be identified and evaluated under CEQA even if allowed by current limited permit conditions. CEQA provides additional protections not necessarily covered by AQMD permit conditions, and this kind of data must be available and transparent for the public CEQA process to be carried out.

[29] Comments on the Initial Study / Mitigated Negative Declaration, Valero Benicia Crude by Rail, June 1, 2013, Dr. Phyllis Fox, attached, http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf

B. Integrating the Wilmington and Carson refinery units and logistics operations is related to the Project, and has the potential to cause major impacts

This map from the Negative Declaration shows the close proximity of the **Tesoro Wilmington and Tesoro Carson refinery operations**, with many residences shown in pink surrounding these facilities (and with labels added for the new Tesoro storage tanks, and the Phillips 66 refinery, next door):



When Tesoro purchased the BP Carson refinery, it planned to take advantage of marine operations to allow changes in crude oil feedstock to feed into the whole refinery complex, and specifically planned to integrate the Carson and Wilmington refineries and the Tesoro and BP "logistics" assets (which provide transportation and storage of feedstocks and products).

Tesoro planned to transfer intermediate feedstock to Carson's cokers and other changes, facilitated by the new storage tank expansions. Tesoro also planned to use BP terminals / "logistics" assets for its own materials, and even to use these terminals to sell excess capacity to third parties (not even mentioned in the ND). Tesoro should have identified these operations for the ND evaluation. Tesoro has further stated:[30]

> *Integrating the BP assets, specifically the logistics, is expected to drive significant value throughout the West Coast system.* ***The Carson refinery has the only very large crude carrier, or VLCC, capable to dock on the West Coast. We will be able to leverage the broader crude oil sourcing optionality and reduce long-haul shipping costs throughout the Tesoro West Coast system.***
>
> *VLCC freight economics on a per barrel basis typically reduce long-haul shipping costs by between $1 and $2 per barrel.* ***Having this capability will allow us to source more economic alternatives to Alaska North Slope crude oil, which has been a significant component of that Carson refinery's historical crude oil slate. We also anticipate benefiting from Carson's two additional cokers, allowing us to further optimize intermediate feedstock transfers between our refineries.*** *We expect feedstock optimization synergies to account for 40% to 45% of the fully-realized synergies.*
>
> *The primary focus of product synergies is delivering the combined regional production sales volumes to end users in the most efficient way possible. Today, Tesoro uses third-party logistics assets to distribute a significant amount of our product volume.* ***Post close, we intend to drive much of that volume through BP's logistic asset, which have excess capacity. In fact, under the operation of Tesoro Logistics, we feel we can drive additional third-party volume through the combined, historically proprietary, logistics network.*** *We expect these cost improvements to account for 15% to 20% of the total synergies.*
>
> ***As we look at the potential for operating synergies, we are confident that significant value can be created through the combination and reconfiguration of the Carson and Wilmington refineries.*** *One expected benefit is increased clean product yields and greater flexibility between gasoline and distillate production, with a focus on distillates. We expect a combined shift of about 25% in our capability to supply market demand for diesel. With about 10% coming from optimizing the combined assets and the remaining 15% resulting from capital investment. This will allow Tesoro to meet the growing demand for distillate fuel on the West Coast. In addition to our plan to lower manufacturing costs in California prior to the acquisition, we also plan to lower costs as a result of the combined operations.*

This discussion and others documented earlier in this comment also show that the overall "logistics" capacity must be evaluated in total, since increased storage in one part of the Tesoro properties can further free up capacity in other parts of its local complex, and also facilitate third party activities and the "reconfiguration" of the two refineries described by Tesoro.

The previously cited Tesoro February 2014 report to the SEC also again identified the integration of the refineries, the "Logistics" operations, and marketing operations.

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[30] Thomson Reuters Streetevents Edited Transcript, TSO - Tesoro Corporation to Purchase BP's Fully Integrated Southern, California Refining and Marketing Business - Conference Call, August 13, 2012, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=3&ved=0CDEQFjAC&url=http%3A%2F%2Fphx.corporate-ir.net%2FExternal.File%3Fitem%3DUGFyZW50SUQ9NDc4MzEzfENoaWxkSUQ9NTExNDM1fFR5cGU9MQ%3D%3D%26t%3D1&ei=ocCPU4zaB4iOqAb_t4LQDA&usg=AFQjCNH0VQpjMISfBGmaQGNaHN0-GBPVsw&sig2=XfnG0PAyBnf1Wz_ud2tniA&bvm=bv.68235269,d.b2k

During 2014, we plan to continue to focus on our strategic priorities described above by:

- *delivering the improved California synergies, resulting from our acquisition and integration of the Southern California refining, marketing and logistics business; . . .*

Tesoro Logistics LP

*TLLP was formed to own, operate, develop and acquire logistics assets to **gather crude oil** and **distribute, transport and <u>store</u>** crude oil and refined products.* [Emphasis added throughout]

These plans, put forth so publicly, repeatedly, and recently, before and after the purchase of the BP properties, should have been disclosed in the ND as part of the Project. The ND is entirely at odds with this public description of Tesoro's own plans. Existing permit conditions listed in the ND are not sufficient to prevent these major refinery changes for which the storage tanks are needed.

The ND identifies the following existing permit conditions and makes very generalized conclusory statements that the Project is not for other purposes, but the ND does not provide the baseline evidence necessary to substantiate these claims, that are so in conflict with the evidence of Tesoro's own statements:

- The existing Tanks 80035 and 80036 are both currently permitted to store petroleum materials including crude oil, hydrocracking unit (HCU) feedstock (a light gas oil . . .
- The two new tanks are proposed to be permitted to store light and heavy crude oils of varying vapor pressures up to 11 pounds per square inch (psi), light gas oils such as HCU feedstock and fluid catalytic cracking unit (FCCU) feedstock, and heavy gas oil
- Tank 80038 is currently permitted to store petroleum distillate products with true vapor pressures less than 0.5 psi such as crude oil and heavy gas oils and is not connected to the vapor recovery system. Tank 80038 currently primarily stores vacuum gas oil, a heavy gas oil. The proposed modifications to Tank 80038 would change the type of commodity to be stored in the tank to also include light gas oil and connect Tank 80038 . . .
- All modifications associated with the proposed project will occur within the confines of the Wilmington Operations . . .
- . . . no modifications will occur at the Carson Operations.
- The proposed project was conceived, and the applications for the proposed project were submitted to the SCAQMD prior to Tesoro's acquisition of the Carson Operations.
- The overall amount of crude oil delivered to the Wilmington Operations will not change from current operations.
- The proposed project will not increase the total amount of crude oil delivered to the Wilmington Operations on an annual basis and will not alter the methods of

crude oil delivery because crude oil will continue to be delivered via ships and pipeline.

- No modifications are proposed to the existing crude oil delivery pipeline from the Marine Terminal. Further, no other pipelines that deliver crude or any other product to the Wilmington Operations will be modified as part of the proposed project.
- Further, Tesoro is not proposing to change the crude oil throughput of the Wilmington Operations or any downstream refining processes because crude oil storage capacity is not a limiting factor for the throughput and production at the Wilmington Operations.
- Refining operations fluctuate and are controlled by many factors, including but not limited to, equipment design parameters, market demand, equipment maintenance schedules, equipment permit limit conditions, and crude oil characteristics (e.g., sulfur content, acidity, specific gravity, etc.).
- . . Tesoro has operated the refining processes at the Wilmington Operations at the maximum capacity in the past and are expected to continue to operate up to or at maximum capacity in the future. Therefore, the baseline crude oil throughput rate and product output of the Wilmington Operations on a daily or an annual basis would not change as a result of implementing the proposed project.
- The refining capacity of the Wilmington Operations is constrained by a number of factors including equipment design parameters, market demand, equipment maintenance schedules, equipment permit limit conditions, and crude oil characteristics (e.g., sulfur content, acidity, specific gravity, etc.).
- The refining capacity is based on the overall design of the refining processes within the Wilmington Operations.
- The heat required to first separate crude oil into various intermediate products, which are later refined further, dictates the amount of crude oil that can be processed overall by the Wilmington Operations.
- Specifically, the Crude Unit, the first step in the refining process, receives the crude oil directly from storage (i.e., from both the existing and proposed storage tanks), has operating limits on the heater, which limits the amount of crude oil that can be processed.
- The Crude Unit operations fluctuate based on conditions of other process units within the Wilmington Operations, market demand, and crude oil characteristics.
- The Crude Unit heater routinely operates at various firing rates and will continue to operate at various firing rates, which is considered to be the baseline at the Wilmington Operations, and the proposed project does not include modifications to the Crude Unit throughput or heater firing rate.

The reasoning that no modifications will occur at the Carson refinery is conclusory, because the Project is currently self-defined as only including the pipe and storage tank increases.

The reasoning that operations "fluctuate" based on "conditions of other process units, market demand, and crude characteristics" is always true of every refinery. This general statement by no means precludes environmental impacts occurring.

No timeline or size of such fluctuations is identified in the ND, so they could be unlimited. Baseline periods and quantification of degree of fluctuations should be identified.

Such fluctuations in crude oil characteristics were identified in the literature previously cited as directly causing environmental impacts.

No baselines were provided for crude oil sulfur, metals, paraffin, or carbon content, or for any crude oil characteristics whatsoever.

Neither does the ND identify whether existing permit conditions for the tanks or other parts of the refinery include any limits on such characteristics.

The ND does not provide any information on the baseline "heat" provided in the crude unit heaters mentioned in the ND.

The ND does not provide any information about when in the past the refinery was operated at "maximum capacity," how maximum capacity is defined, how long ago this occurred, for how long this occurred, and at what percentage of the capacity the refinery is currently running.

Further, the ND does not identify the baseline levels of any other process units within the Wilmington refinery, or within the Carson refinery.

The ND does not identify whether there is existing piping connected to, or close to the Wilmington tanks that could bring materials in the future to the Carson refinery.

The ND does not identify whether the tankage increase in Wilmington could free up other tankage at either refinery, or that could be connected in the near future.

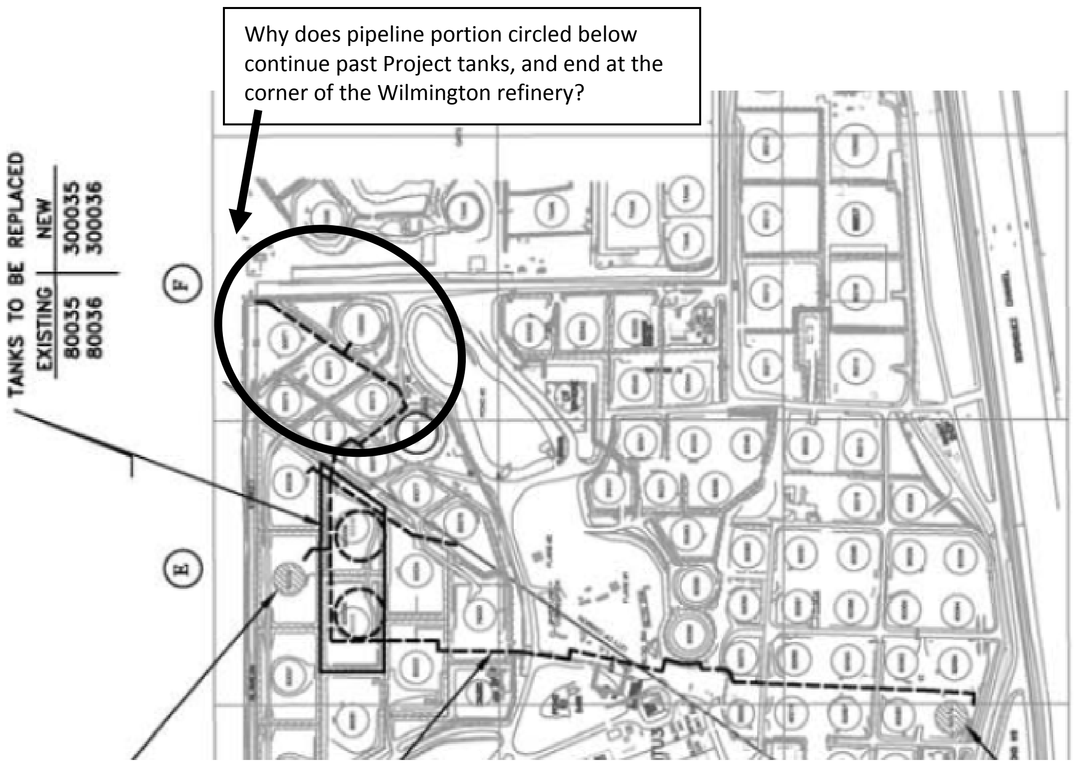
The ND does not identify whether such changes could change the yields of different units within the Carson or the Wilmington refinery.

All these and more such details are essential to an evaluation of the Project and its impacts.

C. The new pipeline across the Wilmington refinery to the Project storage tanks continues *past* the tanks to the corner of the Wilmington property closer to the Carson property, and next to a railway

The ND states that the Project does not involve the Carson refinery, nor any transport by rail, or anything besides the pipeline and the storage tanks. But the new pipeline through the Tesoro facility is routed not only to the new tanks, but *beyond* them, to a corner of the refinery that is close to the Carson portion of the refinery, and is also next to rail lines that traverse the length of the refinery between the Carson and the Wilmington operations.

I have circled the end of the pipeline route which was identified in the refinery layout map provided by the ND. The ND graphic shows an additional length of pipeline *beyond* the Project tanks, to the corner of the Wilmington refinery property, but provides no explanation about the potential for this extended pipeline to connect with additional refinery and logistics operations (including the Carson refinery, the adjacent rail yard, other storage tanks, and potentially even to trucking assets). There is also an extra leg of pipeline indicated without explanation, between two tanks that were not identified as part of the Project.



The ND must be recirculated as a full EIR, and the potential for connections to the Carson portion of the refinery must be identified. Existing nearby pipelines and connections, plans made known to the AQMD of such connections, and the general potential for such connections that the Project facilitates must be evaluated.

In addition to the potential that the storage tanks and pipeline are located in close proximity to the Carson refinery, they are also next to a rail line which runs from top to bottom to the left of the diagram above. The US Energy Information Administration website provides the following charts[31] showing the steady increase of alternative forms of crude oil delivery to oil refineries instead of ship (rail, barge, and truck), including in California. The ND states that Tesoro does not currently transport crude by rail to the Wilmington refinery (at 1-1), but that does not

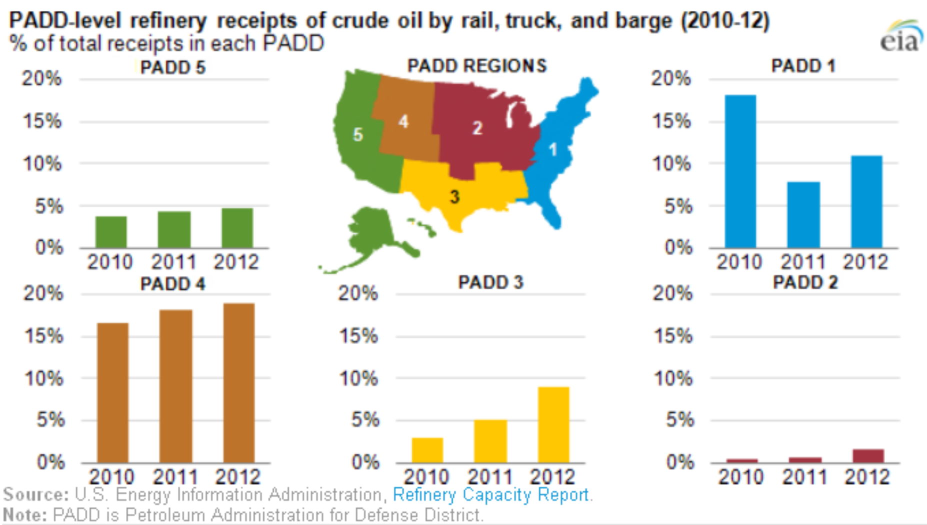
[31] http://www.eia.gov/todayinenergy/detail.cfm?id=12131

preclude the Project from facilitating such a project in the near future, especially given the proximity of the tanks to a rail line. The potential to connect in the future to other local rail should also have been discussed.

Further, Tesoro owns major truck terminal assets. The ND does not provide any information about any applications in process related to truck terminals, baseline activities, potential connections to other transport modes, or the potential for the increase in storage to be connected to Tesoro's terminal. While ship is the more obvious choice at this time, the potential for flexibility of these storage tanks for Tesoro to connect with other transport such as rail and truck should also have been evaluated in the ND.

JULY 17, 2013

Refinery receipts of crude oil by rail, truck, and barge continue to increase



The use of rail, truck, and barge to deliver crude oil to refineries has increased, in part due to increases in U.S. crude oil production. The increases, which vary by region, can be seen in EIA's recently released Refinery Capacity Report.

However, the most crucial omission was the failure to evaluate the Project's role in the integration of the Wilmington and Carson portions of the refinery complex.

D. Volumes and throughput are also publicly planned to increase at the Southern California Marine Terminals according to Tesoro

As described earlier, and also in Tesoro's May 1, 2014 earning call, Philip Anderson, President of Tesoro Logistics LP identified increases in the volumes that its terminals will handle (not just the speed of offloading), increasing throughput capacity[32]:

[32] Thomson Reuters Streetevents Edited Transcript, TLLP – Q1 2014 Tesoro Logistics LP Earnings Conference Call, May 1, 2014, pp .6-7.

> *"We have two of our terminals are being expanded to handle additional capacity, and those expansions will come online this summer. And that will allow us to bump up volumes either very late in the second quarter or early in the third quarter."* . . .
>
> *"Our marine facility down there [Long Beach], 121, which is the large neighbor de-berth in Long Beach, stays pretty full. We have our legacy to Long Beach terminal [Marine Terminal] that is adjacent to our newly acquired, what we call, P-2 in Long Beach. And between P-2 and our legacy Long Beach terminal, we probably have an additional 100,000 plus barrels per day of throughput capacity."*

The ND can't legitimately cut the baby in half – the reason for the increase in offloading through a much larger pipeline and into much larger tankage is admittedly a planned throughput increase in Tesoro's marine terminals.

Tesoro will be enabled to offload over 12 times as fast from its marine loading operations to the new and expanded onshore storage tanks through the Project's expanded 42-inch pipeline. Not only will this enable increased *speed* of offloading, it will free up the terminals to allow scheduling of additional ships to port for offloading at these large storage tanks.

As previously discussed, the US Department of Transportation found that all modes of transportation for Bakken crude need to assess the safety hazards it poses. Further, the AQMD must also evaluate the hazards involved with the transport by ship of heavy tar sands crude, and the diluents that come along with it.

E. The Project has the potential to increase coking

As identified above, there is a major potential to increase the proportion of heavy crude oil from Canada, which would increase coking. The AQMD performed source tests at South Coast refineries and found the following emissions (in lbs per coking cycle).[33] Coking cycles at least once a day. While the AQMD adopted a regulation to reduce these emissions, final deadlines of the regulation are in 2019, so increased coking in the meantime will mean increased impacts from VOCs, particulate matter, sulfur compounds, and the greenhouse gas methane from these operations, which were not evaluated in the EIR. First the ND needs to provide information about the crude slate baseline and coking baseline so that the degree of increased coking can be identified.

[33] Proposed Rule 1114 Working Group Meeting, September 27, 2012, Petroleum Refinery Coking Operations (staff presentation, Slide 4)

AQMD Source Test Results

Company	Test Initial Drum Vent Pressure (psig)	-- lbs/cycle --				
		VOC	PM	Condensable PM/VOC	Sulfur Compounds	Methane
BP	0.89	4.44	3.77	0.66	8.18	165.47
Chevron	0.4	11.16	1.25	12.50	N/A	66.96
Conoco[1]	N/A	N/A	N/A	N/A	N/A	N/A
ExxonMobil[2]	11	1.38	0.34	0.54	N/A	12.72
Tesoro	7	5.3	0.36	1.46	N/A	34
Valero	3.9	4.28	0.26	0.46	0.45	1.86

1. Vent time very short, no sample was obtained
2. Results inconclusive, test was cut short due to safety concerns

F. The increased Storage Tanks themselves have significant impacts, for example, due to the increased tank and pipeline size causing increased risk from fires and earthquakes

The Project treated earthquakes and fires as separate issues. This provides an unrealistic probability that oil and gas fires would occur. The Project instead should be considered to cause a significant increase in the probability of oil and gas fires due to the imminent earthquake hazard. Oil and gas fires are very difficult to extinguish, and could easily spread. Such fires can emit large clouds of hazardous black smoke over the region.

Obviously, the risk of explosion and fire due to Bakken crude oil represents much increased risk, as previously discussed. However, just the increased size of the tankage increases the volume of material vastly, which of course increases the impacts when a fire or explosion occurs, regardless of the type of crude oil present.

A major earthquake is not just a theoretical possibility. The risk of a major earthquake in the region is imminent and severe. A September 2005 Los Angeles Times article,[34] *Katrina's Aftermath, California Earthquake Could Be the Next Katrina,* reported:

> "A state study published last year on hazard reduction paints a sobering picture of California's earthquake danger. About 62% of the population lives in a zone of high earthquake danger, including 100% of the population of Ventura County, **99% of Los Angeles County** and 92% of Riverside County. . . .
>
> **"Researchers at the Southern California Earthquake Center said there is an 80% to 90% chance that a temblor of 7.0 or greater magnitude will strike Southern California before 2024**."

[34] September 10, 2005, Los Angeles Times, KATRINA'S AFTERMATH, California Earthquake Could Be the Next Katrina, by Jia-Rui Chong and Hector Becerra, Times Staff Writers, http://www.latimes.com/news/local/la-earthquake08sep08,1,2126004.story?coll=la-util-news-local

The Southern California Earthquake Center (at the University of Southern California)[35] (SCEC) earlier found:[36]

> *"The last official estimate of earthquake potential in southern California was the 1988 report of the Working Group on California Earthquake Probabilities. The report estimated the probabilities of large "characteristic" earthquakes on major faults, like the San Andreas and San Jacinto faults. The report concluded that there is a 60% chance of at least one large earthquake (M=>7) on the San Andreas fault before the year 2018.*

The report concluded that the probability is even higher, 80-90%, when other faults are included." Such an earthquake could occur today. Severe ground shaking will occur during the inevitable major earthquake in Los Angeles area. Los Angeles' soil types cause increased ground shaking:[37]

The Uniform Building Code does not prevent significant and even severe earthquake damage
In an Environmental Impact Report performed for Industrial Service Oil Company, Inc. (ISOCI) of Los Angeles, the potential for damage to structures (including oil treatment and storage structures) was identified, despite the fact that the facility stated it would comply with the Uniform Building Code:[38]

> ***Based on the historical record, it is highly probable that the Los Angeles region will be affected by future earthquakes.*** *Research shows that damaging earthquakes will be likely to occur on or near recognized faults showing evidence of recent geologic activity.*
>
> *The impacts of an earthquake on the site are considered to be greater than the current conditions since additional structures will be constructed including new treatment and storage facilities.* ***Impacts of an earthquake could include tank and other structural failure.***
>
> *Additional structures at the site must be designed to comply with the Uniform Building Code . . . The goal of the code is to provide structures that will:*
>
> > *(1) Resist minor earthquakes without damage;*
> > *(2) resist moderate earthquakes without structural but with some non-structural damage; and*

---

[35] SCEC (at the University of Southern California) gathers and combines new information about earthquakes in Southern California, is supported by the National Science Foundation and the U.S. Geological Survey, and coordinates efforts of over 50 institutions

[36] *Seismic Hazards in Southern California: Probable Earthquakes, 1994-2024,* Presentation and Panel Discussion Held at the OES Conference, "Northridge Earthquake--One Year Later," January 20, 1995, Southern California Earthquake Center, http://www.scec.org/news/newsletter/issue11.pdf

[37] *"Another project in progress will update this map by showing a higher level of shaking for soft-soil sites. This will lead to a higher rate of damaging shaking because the more common smaller earthquakes will produce greater shaking in soft soil. The result will be to increase slightly the rates for the sedimentary basins such as the Los Angeles basin and the San Gabriel, Ventura and San Bernardino Valleys."* Seismic Hazards Map for Southern California, Southern California Earthquake Data Center, http://www.data.scec.org/general/PhaseII.html

[38] Draft Environmental Impact Report for the Industrial Services Oil Company, Inc. (ISOCI) Hazardous Waste Facility Application, November 2005, page 3-58

(3) resist major earthquakes without collapse but with some structural and non-structural damage. . . .

Thus, the ISOCI EIR found that an earthquake in the region could cause tank and other structural failure, and also found that the Uniform Building code does not preclude all damage from earthquakes. It found that the Code is only meant to cause *resistance* to earthquake damage and collapse. These same risks exist at the proposed Oxy site.

A discussion of remaining risks which exist after compliance with the Uniform Building Code was provided in a publication by Dr. Robert J. Kuntz, President of the California Engineering Foundation, and Daniel L. Tanner, the California Engineering Foundation's Economic Consultant. This document found:[39]

> **The California Building Code offers only minimal protection from seismic damage,** i.e., a structure should not be damaged in a minor earthquake, damaged beyond repair in a moderate earthquake, nor collapse in a major earthquake. However new technologies, such as seismic isolation, can mitigate both structural and building contents damage and are becoming available to government and industry. There is a need for design professionals, building officials, planners, and building owners to become aware of these new technologies, the criteria for their use, and how to incorporate them into practice.
>
> **The Uniform Building Code provides minimal seismic protection determined acceptable by local governments, but Code specifications do not prevent structural damage nor ensure the use of a building after an earthquake.**
>
> Such limited protection is not consistent with the needs of commerce or emergency facilities, which must remain operational after an earthquake, nor does it protect the contents of a building. Two earthquakes which struck near the Lawrence Livermore National Laboratory in California, within two days of each other in January of 1980, caused a total of $10 million in damage. Nearly half of the damage was to laboratory equipment, testing systems, and other building contents.

As an illustration of the potential damage that can occur in an industrial area during a major earthquake, the 1999 earthquake in Turkey was evaluated by the Pacific Earthquake Engineering Research Center. An excerpt of a report on this study is provided below. The report found *"The earthquake struck the industrial heartland of Turkey."* It found that complete structural failures due to earthquake were few in number, but severe damage short of complete structural failure did occur. One example was the failure of floating roofs in crude oil tanks.

Such fracturing and crumpling of support structures and other earthquake damage to industrial equipment not only cause leaks and spills, but could easily cause fires. Even in residences, fires during earthquakes are a known common hazard due to leaking natural gas, broken structures and electrical systems, ignition sources, etc. When damage occurs during major earthquakes to heavy industrial facilities that store, transfer, and process combustible materials, there is even more potential for dangerous fires. The Turkish example included a fire during the 1999

[39] Disaster Recovery Journal, 1999, http://www.drj.com/drworld/content/w2_066.htm

earthquake when a refinery cooling tower failed, and also when eight naphtha- storing fuel tanks burned.

A publication funded by the Earthquake Engineering Research Institute and the Washington Emergency Management Division (2005)[40] found severe damage due to earthquakes, including long term environmental impacts of hazardous material releases. The Report found:

> Fire following the earthquake caused severe damage to the Tüpras refinery. Other observed structural failures in the refinery were to a 115-m-tall smokestack, floating roofs in crude oil tanks, and piles supporting a jetty. Substations and one power generation facility suffered damage ranging from overturned transformers to fractured porcelain switches."

Another publication described the Kocaeli fire, the tank structural damage, fire and collapse, and oil spilled into the sea, and major equipment including a large boiler knocked off its foundation:[41]

Fig. 5. Fire damage to naphtha tanks at Tüpras refinery.

In addition to the risk of fires associated with earthquakes well known to California regulators (as well as those documented after the Turkish earthquake), a publication of the University of Patras, Greece -- *Safeguarding Hydrocarbons Inside Local Earthquake Defense Systems*[42] --

[40] *Scenario for a Magnitude 6.7 Earthquake on the Seattle Fault, A Project Funded by the Earthquake Engineering Research Institute and the Washington Emergency Management Division, February 2005, Excerpts from a publication of the same title to be released March 2005* , page 20, http://seattlescenario.eeri.org/documents/EQ%202-28%20Booklet.pdf

[41] *PEER Center News*, Vol. 2 No. 4 October 1999, http://peer.berkeley.edu/news/1999october/turkey.html , excerpt. *PEER Center News* is a quarterly publication of Pacific Earthquake Engineering Research Center, highlighting research and information of interest to earthquake engineering researchers and professionals. http://peer.berkeley.edu/news/1999october/turkey.html

[42] *Safeguarding Hydrocarbons Inside Local Earthquake Defense Systems,* Project participants: UPS: Seismology Centre, University of Patras, Greece, UEA: School of Environmental Sciences, University of East Anglia, Norwich, England, DEPA: The Public Gas Company of Greece, GSCP: The General Secretariat of Civil Protection, AGISCO, Aspinal & Associates, and ECS: Euroconsultants,

found major fire risks from earthquakes associated with burning hydrocarbons to be a general problem around the world:

> ***"Hydrocarbons, particularly gas, also create a much increased risk of fire as a major secondary consequence following earthquake damage.*** *There is a growing danger that major Greek cities may experience fire damage after a strong earthquake, enhanced by the increased supply of gas into urban areas. Fires following the earthquake at Kobe in Japan 1995 and Turkey 1999 (Fig.1,2) provided a salutary example of impact even in a well-regulated, modern and earthquake conscious country. Longer memories recall the conflagration in Tokyo that followed the 1923 Kwanto earthquake."*


Figure 1 : Fire at factory at Kobe's industrial zone, caused from the earthquake of 17-1-1995.

The new tanks could be used for Bakken or Canadian Tar Sands crude oil according to Tesoro's plans. Bakken crude oil has been shown to be explosive (as in the tragic Lac Megantic rail explosion). It is indisputable that fires and explosions, especially due to earthquake must be evaluated in a new ND related to Tesoro's and Tesoro Logistic's plans to bring Bakken crude oil into its facilities and crude oil tanks.

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http://seismo.geology.upatras.gr/shields/SHIELDS2003.htm

But even with heavy Canadian Tar Sands crude that Tesoro may switch to, an earthquake or other impact could cause a major oil fire. (And that is without considered the addition of volatile diluents added to tar sands crude, which should have been considered.)

An example of severe fires at a facility processing heavier grades of oil includes the Third Coast Industries fire in Houston Texas. The U.S. Chemical Safety and Hazard Investigation Board came to the conclusion that higher flash point ("non-ignitable") materials such as heavy oils can represent major fire hazards.[43] This agency concluded after evaluation of the huge 2002 automotive fluid blending plant fire in Texas, that oils with flash points greater than 200°F classified as "Combustible IIIB" (including motor oils) should be treated with more care regarding fire safety. The Texas fire under investigation could not be put out, and completely destroyed the facility.

In the Texas case, the Chemical Safety Board found that while most of the material onsite at this facility had higher flash points (meaning they wre heavier, less volatile materials), the presence of small amounts of some liquids which were more easily combustible with lower flashpoints, could have caused the fire to start, and then combusted the bulk of the higher flashpoint materials. The Chemical Safety Board found that such higher flash point oils burn "fiercely" once a fire is started.

The Board concluded that fire codes and workplace safety regulations should apply more controls to combustible liquid storage and handling. In the aftermath of the Third Coast fire, the Board communicated its concerns in correspondence to the U.S. Occupational Safety and Health Administration (OSHA). The Chemical Safety Board also found:

> . . . the facility was not designed to contain the contaminated runoff that could result from fighting the fire with water. Fire officials therefore decided they had no choice but to let the plant burn, and they focused on protecting nearby homes from destruction.

A 2005 oil depot fire in the Hertfordshire in the United Kingdom also illustrates how severe offsite impacts from smoky oil fires can be. The inefficient burning of petroleum products at this site caused huge smoking plumes similar to smoking which could occur at the Warren facility if a fire were to break out, due to earthquake or other reasons.[44]

The Hertfordshire Oil Terminal fire showed that such fires cause huge smoky plumes due to poor combustion of hydrocarbon materials. Smoke from an oil fire and/or hazardous materials burning could cause major emissions of particulate matter, PAHs (Polycyclic Aromatic Hydrocarbons), sulfur oxides, heavy metals including lead, mercury, and chromium, chlorinated compounds including deadly dioxins, and many other hazardous compounds.

Smoky fires and gas plumes from such an event could reach nearby residential areas and impact workers offsite and onsite, and could billow for miles. Even a moderate fire could heavily impact

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[43] *Third Coast Industries Fire,* Brazoria County, Texas May 1, 2002, U.S. Chemical Safety and Hazard Investigation Board, CSB Investigation Digest, http://www.csb.gov/third-coast-industries-petroleum-products-facility-fire/

[44] http://en.wikipedia.org/wiki/2005_Hertfordshire_Oil_Storage_Terminal_fire#Causes

neighbors and schoolchildren, especially people with respiratory problems, asthma, or heart conditions, but could also significantly impact healthy adults. The impact would depend on fire size, availability of the fire department (which may not be the case in an earthquake), and how long it takes to put out the fire. In the event of an earthquake, the public has been repeatedly informed that emergency services may not be available for some time, due to obstructions on roadways, and broken water supplies.

The potential of such hazards due to a major earthquake must be evaluated in an EIR.

G. The approximate mile-long expanded pipeline from the Marine Terminal to the Wilmington refinery tanks increases earthquake risks

The ND fails to evaluate the increased volume of crude oil present in the pipeline at any one time, and the increased risk of spill this would cause, especially due to earthquakes. It relies on a stated assumption that annual transport would stay the same (which is also contradicted by Tesoro's published plans, and not inherently true unless specific new conditions are set).

See the discussion above about risks of fires and explosions related to Bakken and Canadian Tar Sands Crude oil in the new expanded storage tanks. The same concern applies due to the large amount of petroleum material that would be added to the approximately mile-long pipeline from the marine terminal to the tanks. Compliance with building codes is meant to reduce risks, but is not considered to eliminate earthquake risk. The ND was wrong in its failure to consider the combination of fire and explosion from earthquakes, which would obviously be increased due to the higher volumes of materials that would be present. The smoky black plumes caused by oil fires contain particulate matter, PAHs (Polycyclic Aromatic Hydrocarbons) and many other harmful compounds that should have been evaluated in the ND with regards to oil fire risk that will certainly be significantly elevated due to the Project increases.

H. Other Potential Project Impacts

Evaluation of the following should be added, especially given the changes in crude slate planned by Tesoro:

- Tank cleaning and degassing: Storage tanks must be periodically cleaned. Emissions from tank cleaning operations for preparation for the modifications of the existing tanks, and later tank cleaning during ongoing operation of both existing and new tanks, was not identified and assessed. Because refinery crude oil storage tanks are very large, and over time crude storage results in accumulation of heavy sludge (called tank "bottoms"), this must periodically be cleaned and removed. SCAQMD Rule 1149 (Storage Tank and Pipeline Cleaning and Degassing) controls but does not eliminate these emissions from the extremely large volumes of hydrocarbon product in these tanks.[45] Tank cleaning and degassing protocols and frequency should be identified and emissions calculated.

[45] Final Environmental Assessment: Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing, April 2008, SCAQMD http://www.aqmd.gov/ceqa/documents/2008/aqmd/finalEA/FEA1149.pdf

In addition, the Hydrocarbon Processing article (Innovative Solutions) identified storage tank waxy buildup and sludge as a specific problem with shale oil storage, with a solution to use chemicals to break up the waxes. The impacts, effects on tank operation and cleaning, and impacts of solutions such as chemicals used to break up waxes, should also be evaluated in an EIR process.[46] Furthermore, impacts related to tar sands storage and tank cleaning, including heavy tank bottoms, and use of diluents must be addressed.

- Pipeline cleaning and degassing: Pipelines are also periodically cleaned and degassed, and in this case, emissions would likely occur not only during future pipeline operation and maintenance activities, but also during the construction connection process with the new tanks. Again, Rule 1149 applies, but does not eliminate all emissions. Further, shorter runs of pipe are exempt, as described in the SCAQMD staff report, and so would not be controlled.[47] Identification of the pipeline lengths, connectors, construction activities, operation, and maintenance activities, including cleaning and degassing, and fugitive emissions from connectors should be specifically described and emissions quantified.
- Flaring of tank and pipeline gases: If flares are used to control degassing emissions for tanks and pipelines, the gas volumes, flare hydrocarbon destruction efficiency, and remaining VOC emissions from flaring should be identified (as well as NOx, SOx, particulate matter, and other emissions).
- Unplanned process shutdowns: Because unconventional crude oils can reduce run-time to half that of planned turnarounds (planned maintenance schedules) as identified in the earlier-cited Oil & Gas Journal article, this means additional air emissions. Unplanned refinery shutdowns increases startup / shutdown and maintenance emissions include increased flaring emissions, potential pressure relief device venting to atmosphere, and also increase the risk of fires and explosions with many associated emissions (not only VOCs, but particulate matter, hydrogen sulfide, all the criteria pollutants, toxics including PAHs (polycyclic aromatic hydrocarbons), and many more). They also increase safety risks for workers and neighbors)

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

[47] At p. 1-13

IV. Conclusion – Potential Impacts are large, have not been mitigated, no alternatives or Cumulative Impacts were analyzed, and an EIR must be developed

My conclusion is that there is an abundance of evidence on the deficiencies in the Project Description and the missing significant environmental impacts due to the full actual Project. Accordingly, AQMD is required to prepare a full EIR. Because the ND incorrectly portrayed this Project as relatively a minor change, numerous impacts are either understated or missing. Mitigation, Cumulative Impacts and Project Alternatives to avoid these significant impacts were not evaluated.

CBE et al. Comments on the Recirculated Draft Environmental Impact Report for the Phillips 66 Propane Recovery Project.

ATTACHMENT A:

Expert Report of Greg Karras on the Recirculated Draft Environmental Impact Report for the Phillips 66 Propane Recovery Project, 12/5/14

Expert Report of Greg Karras
Communities for a Better Environment (CBE)
5 December 2014

Regarding the

Phillips 66 Company Propane Recovery Project
Recirculated Draft Environmental Impact Report (RDEIR)
Released in October 2014 by the Contra Costa County
Department of Conservation and Development
State Clearinghouse #2012072046
County File #LP12-2073

Contents

I, Greg Karras, declare and say:

1. I reside in unincorporated Marin County and am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial health and safety investigation, pollution prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

Qualifications

2. My qualifications for this opinion include extensive experience, knowledge, and expertise gained from nearly 30 years of industrial and environmental health and safety investigation in the energy manufacturing sector, including petroleum refining, and in particular, refineries in the San Francisco Bay Area.

3. Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from refineries, to assess environmental health and safety impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I served as an expert for

CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives. I served as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the Chevron Richmond refinery "Modernization Project" now subject to review pursuant to a California Court of Appeals Order,[1] and the Phillips 66 "Rail Spur Extension and Crude Unloading Project" now before San Luis Obispo County.[2] I serve as an expert for CBE in collaboration with community, labor, and other groups in a project involving investigation of environmental health and safety impacts of, and alternatives to, refining lower quality crude oils.

4. I authored a technical paper on the first publicly verified pollution prevention audit of a California petroleum refinery in 1989 and the first comprehensive analysis of refinery selenium discharge trends in 1994. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. From 1992–1994 I authored a series of technical analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts.

5. My recent publications include the first peer reviewed estimate of combustion emissions from refining denser, more contaminated 'lower quality' oil based on data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010, and a follow up study that extended this work with a focus on California and Bay Area refineries, which was peer reviewed and published by the Union of Concerned Scientists in 2011. I also presented invited testimony on *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's public hearing on the Chevron Richmond refinery fire that was held on 19 April 2013. My CV and list of publications were submitted with my September 2013 report in this matter.

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[1] See *CBE v. City of Richmond* 184 Cal_App.4th.
[2] See also Contra Costa Pipeline Project file, County File #LP072009, SCH #2007062007.

Scope of Review

6. In my role at CBE I have reviewed the Phillips 66 Company 'Propane Recovery Project' Recirculated Draft Environmental Impact Report (RDEIR), 'Rail Spur Extension and Crude Unloading Project' Revised Draft Environmental Impact Report (Rail Spur RDEIR),[3] 'Throughput Increase Project' Final EIR (Throughput Increase FEIR),[4] and the projects or project components discussed in those documents. I commented previously in this matter and reassert my previous comments[5] as they remain valid and have not been addressed in the RDEIR. My review of the project and RDEIR reported herein is focused on the adequacy of the project description and analysis in the RDEIR for evaluating potential environmental impacts of the project. My opinions on these matters and the basis for these opinions are stated in this report.

Changes to the Project

7. The RDEIR describes the project differently from the DEIR in several ways that are identifiable from detailed review but are not discussed in the RDEIR as changes in the project description or changes in the project. These changes involve the *amounts* of propane and butane (LPG) to be recovered, the *sources* of that LPG, the *streams* to be hydrotreated, and the *scope* of cooling system changes. Each is discussed in turn below.

8. Amounts of propane and butane that the project could recover were described as 4,200 barrels per day (b/d) of propane and an additional 3,800 b/d of butane in the DEIR. In contrast, the RDEIR asserts *both* a draft air permit limit on the lump sum of propane and butane to be recovered (14,500 b/d LPG; RDEIR at 3-31, 3-33) *and* a project design basis of 5,580 b/d propane and 4,996 b/d additional butane (15,474 b/d LPG including the butane that is already recovered; RDEIR at 3-33, 3-34). No irrevocable commitment to retain the proposed 14,500 b/d permit limit throughout the 30–50 year expected operation of the project is asserted or documented. The RDEIR does not note that the design basis is thus relevant to potential impacts, or explain this change to the project in its text.

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[3] 'Rail Spur' proposal; SCH #2013071028; now pending before San Luis Obispo County.
[4] 'Throughput Increase' proposal; SCH #20081010111; now pending final project approval.
[5] My 4 Sep 2013 report regarding this matter (Karras Rodeo Report-1), 7 Jan 2014 Supplemental Evidence–B, 14 Jan 2014 Supp. Evidence–C, 20 Jan 2014 Supp. Evidence–D (co-authored with Roger Lin), and 24 Nov 2014 report regarding the 'Rail Spur Extension and Crude Unloading Project' (Karras Rail Spur Report) are appended hereto as attachments 1, 2, 3, 4, and 5, respectively. Exhibit 1 of my Rail Spur report is appended hereto as Karras Exhibit 1.

9. Sources of the LPG to be recovered, as described in the DEIR, did *not* include several streams feeding 'RFG-A.' (DEIR Figure 3-6.) These 'RFG-A' streams are now included among those from which LPG could be recovered. (RDEIR Figure 3-6.) This change in the project description reveals undisclosed changes in hydrogen plant feed and further implicates feedstock from the Santa Maria facility (see figs. 3-4, 3-6), but the RDEIR includes no discussion of any potential effects from this change in the project.

10. Additional hydrocarbon streams would be treated by the proposed new hydrotreater, but this change and its implications are not discussed in the RDEIR. Naphtha streams from the heavy gas oil hydrocracker (Unit 246) and the ULSD diesel hydrotreater (U250) are fed to reforming units U231 and U244 now, but the revised project description would instead route them through the new hydrotreater. (Compare DEIR and RDEIR figures 3-4, 3-5, and 3-6.)

11. The project would modify the Rodeo facility's antiquated once-through cooling (OTC) system and those modifications would include, among other things, new heat exchangers. However, cooling system changes described in the DEIR were limited to cooling the proposed new propane *recovery* (DEIR at 3-27) while the RDEIR appears to expand this description to cover all cooling "demands for the proposed Project." (RDEIR at 3-37.) The RDEIR's text does not mention or explain this change in the project description. This omission further compounds its lack of disclosure regarding the process sources and amount of the additional heat to be transferred to the San Francisco Bay.

Feedstock Change

12. Changes in the type, quantity, and quality (e.g., density, distillation properties, LPG content, hydrogen content, sulfur content, metals content, organic acids content) of crude oil processed are not disclosed in the RDEIR. Crude oil is the basic feedstock of oil refining. This nondisclosure is a fundamental flaw in the RDEIR.

13. The RDEIR asserts that the project would not have "any effect on the types and/or quantities of crude oil feedstocks that can be processed," does not "propose to add, change, or modify the operation of other process units, such as the coker" (RDEIR at 3-28), and "has no connection to the transportation of crude oil by rail" (RDEIR at 3-7). These assertions are unsupported, misleading, and incorrect. Crude is the feedstock for

this LPG production. Feedstock and products are key process variables that are fundamentally interrelated. Phillips 66 and other California refiners are switching to different crude feedstock sources at present. Crude from different sources can yield different amounts of propane and butane in refinery distillation processes, and in refinery cracking processes such as coking and hydrocracking. These connections between refinery crude feeds, processing, and LPG production are beyond reasonable dispute. Moreover, Phillips 66 does, in fact, propose to change (increase) coking and other processing of new types of crude brought in by rail.

14. Phillips 66 proposes to increase coking and other processing rates via its 'Throughput Increase Project, which would increase its Santa Maria Facility (SMF) crude processing rate.[6] Because the SMF cannot make gasoline, diesel or jet fuel and sends all the semi-refined crude liquids it produces to Rodeo for further processing, that would necessarily increase the volume of oil from the SMF that would be processed at Rodeo.[7] Some of this increasing oil volume from the SMF would be processed by the Rodeo coking unit U200, its hydrocracking units U240 and U246, and its diesel hydrotreater U250 (after U240 'Prefrac' distillation; see 'SMGO,' RDEIR Figure 3-4). The RDEIR fails to disclose this proposed change in the operation of the coker and other refinery process units to process larger amounts of crude delivered through the SMF.

15. As stated, crude feedstock yields LPG from distillation (e.g., 'prefractionation') and also from cracking (e.g., coking and hydrocracking). Thus, SMF crude inputs are connected to the Rodeo LPG recovery proposal through distillation and cracking of the semi-refined oils sent from the SMF to Rodeo to finish the processing needed to make gasoline, diesel and jet fuel from crude. Phillips 66 currently proposes to receive this crude feedstock at the SMF by rail.[8] Therefore, its assertion that the project "has no connection to the transportation of crude oil by rail" is a clear error in the RDEIR.

16. The publicly verifiable data in the record indicate that insufficient propane and butane is recoverable in the project baseline to implement the project without additional cracking process feedstock, additional LPG-rich feedstock, or both. My past comments and those of others raised and documented this finding.[9] Estimates based on publicly

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[6] *See* Throughput Increase FEIR; *see* also Rail Spur RDEIR at 2-35 (pending final approval).
[7] *See* Karras Rail Spur Report at paragraphs 15–28.
[8] *See* Rail Spur RDEIR; currently in CEQA review before San Luis Obispo County.
[9] *See* attachments 1, 3, 4; reports and comments of P. Fox on the LPG and Rail Spur projects.

verifiable, plant-specific data for LPG recoverable with available technology indicate that roughly half Phillips' proposed LPG recovery capacity would be idled in these 'baseline' conditions.[10] Unfortunately, instead of reporting and analyzing publicly verifiable data on current and potential sources of recoverable LPG, the RDEIR dismisses this evidence with unsupported and contradictory assertions. The RDEIR's revised estimate now tacitly admits a small baseline LPG shortfall below project design capacity, ranging from 10–31% of this capacity being idled, depending upon the averaging period chosen.[11] However, the RDEIR estimate is not supported by publicly verifiable data, overestimates the baseline by applying maximum conditions as average ones for at least some streams, and further inflates the baseline by including LPG streams that are not feasible to recover in its 'recoverable' estimate.[12] Compounding its errors, the RDEIR omits industry-wide data revealing that its estimate appears improbably high.[13] Thus, rather than any 'battle of experts' problem, the RDEIR simply ignores all the data refuting its conclusion on this key point while including no supporting data, but its analysis appears misleading in another way as well. Instead of a typical 'baseline' period before the project notice, it asserts an LPG estimate for 2013 (RDEIR at 3-35), a year when the refinery had already begun to boost crude feedstock volume, and did so at least in part on new tar sands oil feedstock[14]—the very same change it insists has nothing to do with the project.

17. The RDEIR's new assertion that "no new butane or propane can be added to the semi-refined products sent from the" SMF because of "vapor pressure limits" on storage tanks along the company's proprietary pipeline from the SMF to Rodeo[15] is unsupported, erroneous, and misleading. This assertion is not supported by even a shred of data in the RDEIR—and it is improbable, as the naphtha (pressure distillate) and gas oils produced and sent by the SMF would be expected to have vapor pressures well below the limits cited. Data the RDEIR *should* have included but did not show this assertion is wrong.

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[10] <u>See</u> attachments 1, 3, 4; reports and comments of P. Fox on the LPG and Rail Spur projects.
[11] RDEIR at 3-33 through 3-35, reporting unsupported total LPG averages of ≈10,600 b/d (month of Dec 2013) and 13,970 b/d (2013-annual) vs. a project design basis of 15,474 b/d.
[12] <u>See</u> attachments 1, 3, 4; and the reports and comments of P. Fox, <u>*esp*</u>. on Refinery Manager Evans' 6 Jan 2014 *Response to Appeals*. Note also that 'RFG-A' streams the RDEIR estimate includes were <u>*not*</u> fed to LPG recovery before the project description changed (<u>*see*</u> paragraph 9).
[13] <u>See</u> Att. 3 at 1 (*maximum monthly* West Coast yield less than half claimed Rodeo *annual* yield).
[14] <u>See</u> Rail Spur RDEIR at 2-35 (compare 2010–2012 vs. 2013 SMF crude throughputs) and 2-31 (SMF crude feed has been up to 7% bitumen-derived 'dilbit' crude "for about one year").
[15] RDEIR at 3-25, 3-26; <u>see</u> also Phillips SFR Manager's 1/6/14 'Response to Appeals.'

(See Fox SMF Rpt–2.)[16] The tanks are controlled and thus exempt from the claimed vapor limits, their measured vapor pressures are far below the claimed limits, or both. (Id.) This assertion also ignores—and distracts attention away from—the LPG feedstock sent to Rodeo not as LPG, but as gas oils and pressure distillate/naphtha that yield significant amounts of LPG during processing at Rodeo.

18. Ultimately, the RDEIR's assertion that the project "would not require the Refinery to change the basic feedstocks that are currently received and processed" because it "does not propose to increase the production of propane or butane"[17] is unsupported and inaccurate because it ignores ongoing changes in crude feedstock. This existing condition is a known impetus for projects at the refinery that has been acknowledged by San Luis Obispo County[18] and by Phillips 66 itself.[19] As shown below, the refinery will need to replace its current crude feedstock in order to produce sufficient propane and butane to implement the project over its expected operational duration.

19. Currently changing crude feedstock, driven by declining San Joaquin Valley Pipeline (SJVP) crude inputs to the Rodeo Facility, has been established—and accepted by Phillips 66 and public agencies alike—as a driving factor in Phillips' Marine Terminal Offload Revision Project. (BAAQMD, 2012; CSLC, 1995.)[20] That increase in crude and gas oil throughput over the refinery's wharf is replacing declining SJVP crude deliveries, but it is limited to only 51,182 b/d. (Id.) Semi-refined oils delivered via upgrading of crude by the SMF, the only other way Rodeo gets oil feedstock, averaged ≈38,000 b/d as SMF crude throughput from 2010–2012 and could increase to 48,950 b/d, roughly the same throughput as the new wharf limit, with the proposed Throughput Increase.[21]

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[16] Expert report of Phyllis Fox (Fox Rail Spur Rpt–2), attached to CBE 5 Dec 2014 comments.
[17] RDEIR at 3-28.
[18] *See* Rail Spur RDEIR at 2-36 (need for project driven by declines in local crude sources).
[19] *See* BAAQMD, 2012. *Marine Terminal Offload Limit Revision Project CEQA Initial Study* at i, 1–3, 17 (crude and gas oil offloading limit increase of 20,500 b/d to 51,182 b/d to replace equal volume of California crude via pipeline, based on CSLC 1995 EIR); and CLSC 1995 FEIR (SCH #91053082) at § 4 page S-4 ("it is assumed that sources of San Joaquin" and "Alaskan crude, will decline" and "[m]ore reliance will be placed on crude imports from foreign sources"). *See* also Phillips 66 Chairman and CEO Greg Garland, quoted in Thompson Reuters, *DECEMBER 13, 2012 / 01:30PM, PSX – Phillips 66 First Annual Analyst Meeting;* www.streetevents.com ("opportunity to improve performance in California is really around getting advantage crudes to the front end of the California refineries").
[20] BAAQMD, 2012 and CSLC, 1995 as cited above.
[21] *See* Rail Spur RDEIR at 2-35.

20. Abundant evidence that the RDEIR does not include or analyze demonstrates that declining local and regional crude production could greatly affect SMF operation.[22] Total California crude production supplied to refineries statewide has declined by 43% from its peak of 1.10 million barrels per day in 1986 to 631 thousand barrels/day (Mb/d) in 2013, and California crude now supplies only 40% of statewide refinery crude input.[23] Statewide, coastal onshore production was 137 Mb/d in 1977 but only 60.3 Mb/d in 2012, indicating a gross decline of –56% and a year-on-year decline averaging –2.0%/year in this period.[24] State offshore production peaked in 1978 at 107 Mb/d and was 35.6 Mb/d in 2012, indicating a gross decline of –67% and a year-on-year decline averaging –3.6% per year.[25] In California's San Joaquin Basin, crude production peaked in 1986 at 745 Mb/d and was 405 Mb/d in 2012, a gross decline of –46% and annual decline averaging –2.3%/y.[26] California federal Outer Continental Shelf (OCS) production peaked in 1995 at 197 Mb/d and was 41.1 Mb/d in 2012, a gross decline of –79% and an average year-on-year decline during this period of –8.3%/y.[27] Some 13 Central Coast OCS, state offshore and onshore fields are identified as the sources of crude for the SMF.[28] Total production from these 'local supply' sources was 191 Mb/d in 1995 but only 67.1 Mb/d in 2012, a gross decline of –65% and a year-on-year decline ranging from –2.8%/y since 2003 to –5.8%/y since 1995.[29] See Figure 1. This 2.8–5.8%/year decline is within the range found elsewhere in the state that is discussed above (2.0–8.3%/y). As Figure 1 illustrates, this 2.8–5.8%/year rate of decline could result in total production from these 'local supply' sources falling below the maximum capacity of the SMF to process crude within a few years, and then falling further, to a small fraction of SMF design capacity, within the expected operating life of the proposed rail spur. When its crude rate falls too far below the design specifications of its existing equipment, such as its pipelines and vacuum unit, the existing SMF cannot operate efficiently or profitably.

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[22] This finding also applies to the Rodeo Facility of the Phillips 66 San Francisco Refinery.
[23] Cal. Energy Comm. (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).
[24] U.S. Energy Information Admin. (http://www.eia.gov/dnav/pet/pet_crd_pres_dcu_rcac_a.htm).
[25] U.S. EIA (http://www.eia.gov/dnav/pet/pet_crd_pres_dcu_rcasf_a.htm).
[26] U.S. EIA (http://www.eia.gov/dnav/pet/pet_crd_pres_dcu_rcaj_a.htm).
[27] U.S. EIA (http://tonto.eia.gov/dnav/pet/hist/LeafHandler.ashx?PET&s=RCRR10R5F+1&f=A).
[28] The Pt. Pedernales, Pt. Arguello, Santa Ynez, Elwood S. Offshore, Arroyo Grande, San Ardo, Cat Canyon, Orcutt, Santa Maria Valley, Lompoc, Casmalia, McCool Ranch, and Zaca fields. Further, a pipeline system connected only to local oil fields "is currently the only way that the Phillips 66 [SMF] can receive crude oil." ***See*** Rail Spur RDEIR at 2-35.
[29] Data from State Division of Oil, Gas, & Geothermal Resources (DOGGR) and US DOI Bureau of Safety and Environmental Enforcement (BSEE). See Exhibit 1 Appended hereto.

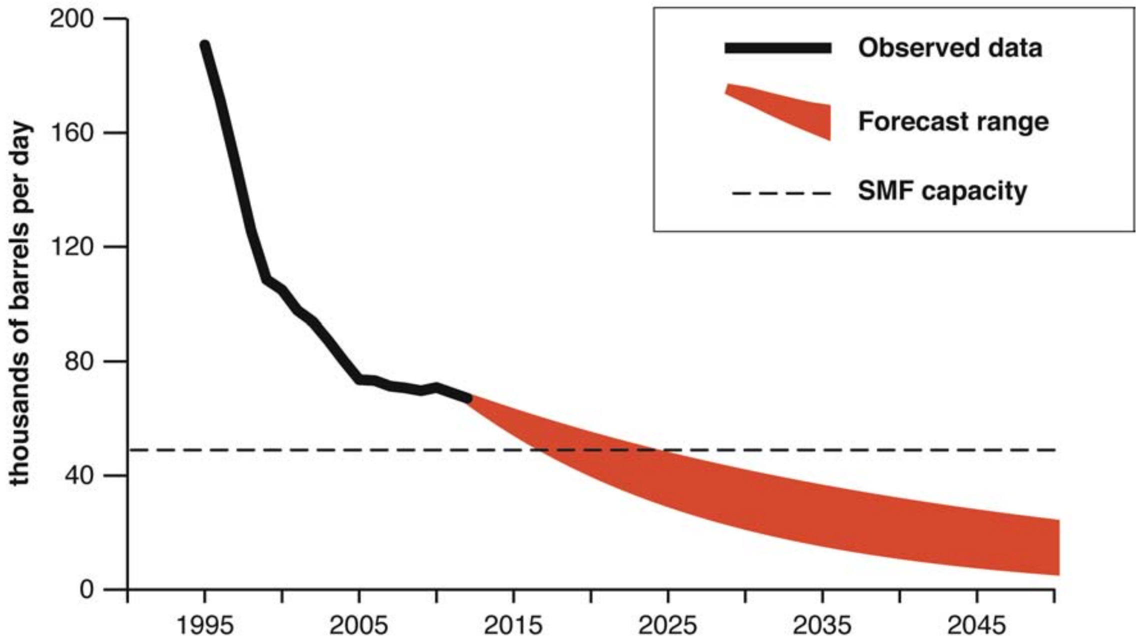

Figure 1. Total Central Coast OCS, offshore, and onshore oil production of fields supplying crude oil to the Phillips 66 SMF from 1995–2012, and forecast to 2050.

Observed production by year, in thousands of barrels per day (Mb/d)

1995	191 Mb/d	2001	97.7 Mb/d	2007	71.3 Mb/d
1996	171 Mb/d	2002	93.8 Mb/d	2008	70.7 Mb/d
1997	149 Mb/d	2003	87.3 Mb/d	2009	69.7 Mb/d
1998	126 Mb/d	2004	80.2 Mb/d	2010	70.9 Mb/d
1999	108 Mb/d	2005	73.6 Mb/d	2011	69.0 Mb/d
2000	105 Mb/d	2006	73.3 Mb/d	2012	67.1 Mb/d

Data from Cal. Dept. of Conservation (DOGGR) and U.S. Dept. of Interior (BSEE); *see* Exhibit 1 for details. Oil fields included are Pt. Pedernales, Pt. Arguello, Santa Ynez, Elwood S. Offshore, Arroyo Grande, San Ardo, Cat Canyon, Orcutt, Santa Maria Valley, Lompoc, Casmalia, McCool Ranch, and Zaca.
Forecast range based on range of average year-on-year decline rates (2.8–5.8%/yr) from a more recent (2003–2012) and longer (1995–2012) period, after CEC method (*see* CEC-600-2010-002-SF at 138).
SMF capacity is Santa Maria Facility throughput proposed (48.95 Mb/d) from Rail Spur RDEIR at 2-35.

21. If built as proposed the project would be expected to have a useful operational duration of 30–50 years (until 2045–2065).[30] As shown in paragraph 20 and Figure 1, current crude sources supplying project feedstock would dwindle during this period.

[30] *See* Karras Rodeo Report-1 at paragraph 11. This estimate is consistent with those for similar refining equipment made in other CEQA reviews (Id.) and with San Luis Obispo County's estimate (Rail Spur RDEIR at 2-36). The RDEIR omits this crucial information about the project, but "amortizes construction emissions over a 30-year project lifetime" (RDEIR at 4.5-9).

22. As stated, available evidence indicates insufficient currently recoverable LPG, and even the RDEIR's unsupported overestimate of currently recoverable LPG is smaller than the project's design capacity. Processing the same oil feedstocks in smaller amounts will yield even less LPG. Thus, even if the RDEIR's unsupported overestimate is assumed—and even if the SMF does not shut down when its crude supply dwindles to a small fraction of its capacity—in the absence of a new crude source to replace dwindling current supplies from the SMF and SJVP during its operating life, the project could not be implemented as proposed.

23. Phillips' crude by rail proposal at the SMF would deliver ≈52,000 barrels per unit train and unload each train in ≈11.5 hours, so it could amply supply the new imported crude oil for the proposed throughput increase to 48.95 Mb/d.[31] Further, this proposal's asserted exclusion of Bakken crude, heated unloading equipment, weight limits on rail tanker car crude volume, and asserted crude sources,[32] together with the predominance of the tar sands among available crude sources of this type indicate that tar sands oil would most likely dominate the new crude feedstock enabled by the project. This would be a dramatic change in refinery feedstock: Tar sands bitumen is *fundamentally* different from heavy oil or conventional crude.[33]

24. In sum, Phillips' proposal to recover additional LPG from its crude feedstock is inextricably related to its proposal to replace currently dwindling crude feedstock with new feedstock that most likely will be dominated by fundamentally different bitumen-derived 'tar sands' oils. My previous comments found the reasonable potential that this project-related feedstock switch could result in significant potential catastrophic hazard, air quality, public health, and climate impacts.[34] Instead of addressing these potential impacts the RDEIR asserts the unsupported and erroneous conclusion that the project "has no connection to" the crude switch.[35] Therefore, its failure to disclose, describe, analyze and address this project-related change in oil feedstock and its environmental implications represents a fundamental flaw in the RDEIR.

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[31] See Rail Spur RDEIR at 2-22, 2-29 and 2-35.
[32] Rail Spur RDEIR at 2-1, 2-14, 2-15, 2-22 and 2-33.
[33] See Meyer et al., USGS Open-File Report 2007-1084 (http://pubs/usgs/gov/of/2007/) at 2.
[34] Karras Rodeo Report-1 at paragraphs 56–83.
[35] See paragraphs 13–23; see also FEIR at 3.2-130, response to comment that undisclosed changes in crude oils processed could create undisclosed environmental impacts: ("The DEIR did not address changes in crude oil use because … the objectives of this Project would be achieved irrespective of crude oil feedstock selection."). (Emphasis added.)

Project Scope

25. Phillips' Santa Maria and Rodeo facilities (SMF and RF, respectively) are interdependent parts of its San Francisco Refinery (SFR), and its SMF rail spur, SMF throughput increase, and RF LPG[36] proposals are interdependent parts of a larger project that has been piecemealed,[37] as shown below.

26. SFR is identified and reported as a single oil refinery comprised of the SMF and RF by government and industry authorities,[38] by San Luis Obispo County,[39] and by Phillips itself (see Phillips 66 website).[40] SFR's primary, and from Phillips' perspective essential, products are gasoline, diesel and jet fuel. (Id.) But the SMF does not make *any* finished gasoline, diesel, or jet fuel by itself, and lacks the hydroprocessing and naphtha reforming capacity necessary to do so—all of the SFR hydrocracking, hydrotreating, hydrogen production, and naphtha reforming capacity is at the RF.[41] Instead, Phillips 66 sends all of the partially upgraded feedstock that the SMF produces (gas oil and naphtha-pressure distillate) through a proprietary pipeline to the RF, where all of the SFR's finished gasoline, diesel and jet fuel is made and then shipped from the RF product pipelines and wharf for sales.[42] The SMF thus depends upon the RF for transport fuel production and financially sustainable operation.

27. The RF, in turn, relies on the SMF for sufficient feedstock delivery and deep conversion (coking) capacity. San Joaquin Valley Pipeline (SJVP) crude delivery to the RF is declining with declining San Joaquin Basin production (see paragraphs 19–20), and this decline has already driven a throughput increase at the RF wharf (BAAQMD,

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[36] 'Propane Recovery' proposal; SCH #2012072046; this RDEIR.
[37] These points are made in my expert report submitted to San Luis Obispo County as well.
[38] *Compare* refinery capacity reports by EIA (http://www.eia.gov/petroleum/refinerycapacity/) and *Oil & Gas Journal* (http://www.ogj.com/ogj-survey-downloads.html#worldref) to facility configuration and throughput reports by State Regional Water Quality Control board permits (Order R3-2013-0028 at Table F-9 and Order R2-2010-0027 at Table F-1C); *see* also Rail Spur RDEIR at 2-32; Throughput Increase FEIR at 2-12; and RDEIR at 3-10 through 3-19.
[39] *See* Rail Spur RDEIR at 2-4; Throughput Increase FEIR at 2-1. Notably, the RDEIR's only references to the SFR are in its reference titles and a footnote on page 1-3 regarding changes of ownership: it fails to disclose that the RF is a component of a single, larger refinery, the SFR.
[40] www.phillips66.com/EN/about/our-businesses/refining-marketing/refining/Pages/index.aspx
[41] *Compare* refinery capacity reports and facility-level orders and EIRs cited in the note above.
[42] *See* Rail Spur RDEIR at 2-4 and the Throughput Increase FEIR at 2-1; s*ee* also the product export facilities discussion in the RDEIR at 3-18. The SMF was sited on the Central Coast to tap local crude sources there. This, together with San Francisco Bay/Delta tanker port capacity afforded to the RF, helps explain the SFR's geographically unusual design.

2012).[43] Even with this new wharf capacity, however, oil delivery across the wharf is limited to only 51.2 Mb/d. (Id.) Crude delivery and upgrading via the SMF—the only other way the SFR receives crude—is a substantial portion (≈38.0 Mb/d[44]) of its total crude supply. All SFR crude input is necessarily finished at the RF to make a financially sustainable product slate (see paragraph 26), so the SFR, and thus the RF, needs this SMF-derived crude. Moreover, roughly half of the coking capacity utilized by the SFR currently is at the SMF.[45] The RF needs this additional deep conversion capacity at SMF to feed its hydrocrackers sufficient heavy gas oil for the SFR to convert its crude slate into gasoline, diesel, and jet fuel efficiently and, from Phillips' standpoint, economically. Indeed, the new heavy gas oil hydrocracker at the RF that is fed this SMF gas oil[46] was built for exactly that purpose,[47] and could become a stranded asset without that feed.

28. Similarly, the SMF relies on existing infrastructure for feedstock. The SMF relies on a pipeline system fed by declining local crude supplies that cannot maintain its current crude rate for long, much less sustain a crude rate increase of ≈29% to 48.95 Mb/d, the proposed throughput increase—but the rail proposal could do so. (Paragraphs 20–23.)[48] In the absence of a new port, interstate pipeline, long-distance trucking plan, or any other credible proposal for sustained delivery of sufficient imported crude to implement this project component, the proposed throughput increase is dependent upon the rail spur.

29. A third component of the piecemealed project involves propane and butane, which are liquefied petroleum gases (LPG).[49] LPG is in refiners' hydrocarbon streams because it distills out from oil feeds, and because it is created in coking, hydrocracking, and other refining processes that 'crack' (break apart) larger, denser, or higher boiling-point hydrocarbons in the oil feeds. LPG is burned as refinery fuel, recovered, or both. Not all LPG present in all refinery hydrocarbon streams is recoverable with currently

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[43] See BAAQMD, 2012. *Marine Terminal Offload Limit Revision Project CEQA Initial Study* at i, 1–3, 17 (*crude and gas* oil offloading limit increase of 20,500 b/d to 51,182 b/d to replace equal volume California *crude* via pipeline, based on CSLC 1995 EIR); and CLSC 1995 FEIR (SCH #91053082) at Section 4 page S-4 ("it is assumed that sources of San Joaquin" and "Alaskan crude, will decline" and "[m]ore reliance will be placed on crude imports from foreign sources").
[44] From 37,785 b/d (2010), 38,701 b/d (2011), and 37,602 b/d (2012); Rail Spur RDEIR at 2-35.
[45] From 23,200 b/d (Order R3-2013-0028 Table F-9) v. 47,000–48,000 b/cd (*Oil & Gas J.*; EIA).
[46] See RDEIR at 3-10 through 3-12.
[47] See 'Clean Fuels Expansion' Nov. 2006 Prelim. EIR SCH #2005092028 at 3-1, 3-18, 3-22/23.
[48] See also Rail Spur RDEIR at 2-35 (pipeline system from local oil fields "is currently the only way that the Phillips 66 [SMF] can receive crude oil").
[49] Herein, 'LPG' means propane and butane, the only gases Phillips proposes to recover.

available technology. Propane and butane that is recovered can be sold as fuel or as petrochemical feedstock, and butane can be blended into winter gasoline. As stated, Phillips 66 proposes to recover propane and additional butane at its RF. It proposes to install a hydrotreater, recovery columns, pressure storage bullets, and a rail loading spur and rack, and—decades after other refiners stopped exploiting the San Francisco Bay/Delta in this way—would expand Phillips' once-through cooling system. The three components of the project are in review or await final approval before Contra Costa County or San Luis Obispo County and none of them has been implemented.

30. The publicly verifiable data in the record indicate that insufficient propane and butane is recoverable in the project baseline to implement Phillips' LPG proposal without the additional cracking process feedstock, additional LPG-rich naphtha/pressure distillate, or both, that its SMF throughput increase and rail spur could supply. My past comments, and those of others, raised and documented this finding. Unfortunately, instead of reporting and analyzing publicly verifiable data on current and potential sources of recoverable LPG, the counties' environmental reviews, thus far, have dismissed those comments with unsupported and contradictory assertions. (<u>See</u> paragraph 16.)

31. The new argument that vapor pressure limits do not allow any more LPG to be sent from the SMF to Rodeo[50] is totally unsupported by any data in the RDEIR, improbable, and shown by data the RDEIR omits to be erroneous. (<u>See</u> paragraph 17.) This 'vapor pressure' argument also ignores, and thereby distracts from a crucial point: LPG feedstock sent to Rodeo not as LPG, but as gas oils and pressure distillate (naphtha), yields substantial amounts of recoverable LPG from processing at Rodeo. Ignoring this link between the facilities' project components would be a fatal error.

32. Some of the volumetric implications for RF hydrocracking and reforming of gas oil and naphtha in a 'SMF projects' scenario, in which the rail and throughput proposals are implemented, and in a 'No SMF projects' scenario, in which those proposals are not implemented, are summarized in Table 1. Gas oil and naphtha/pressure distillate are the major SMF exports to the RF. Gas oils are hydrocracked at the RF to make gasoline, diesel, and jet fuel sized hydrocarbon molecules with high enough hydrogen:carbon ratios

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[50] RDEIR at 3-25, 2-36. <u>*See*</u> *also Response to Appeals by the Rodeo Citizens Association and Communities for a Better Environment;* letter from Mark E. Evans, Phillips 66 San Francisco Refinery Manager, to Chair Karen Mitchoff and Members of the Contra Costa County Board of Supervisors. 6 January 2014; and Rail Spur RDEIR at 2-31.

Table 1. Estimated oil feedstock effects at the refinery's Rodeo Facility in 'project' and no project' scenarios for the Santa Maria crude by rail and throughput increase.
*****Figures EXCLUDE additional LPG-boosting effects of tar sands 'dilbit' processing*****

Data in thousands of barrels/day (Mb/d), and percent

	Current conditions	Santa Maria Project Component Scenarios	
		SMF projects	No SMF projects
Santa Maria Facility			
crude throughput (Mb/d)	38.00	48.95	17.82
Δ vs. current (%)	——	29%	-53%
naphtha to Rodeo (Mb/d)	11.63	15.00	5.45
% Δ vs. current	——	29%	-53%
gas oil to Rodeo (Mb/d)	20.71	26.68	9.71
% Δ vs. current	——	29%	-53%
Rodeo Facility			
hydrocracking			
capacity (Mb/d)	58.00	58.00	58.00
feed rate (Mb/d)	51.75	57.72	40.75
utilization rate (%)	89%	99%	70%
Δ in feed rate (%)	——	11%	-21%
naphtha reforming			
capacity (Mb/d)	31.00	31.00	31.00
feed rate (Mb/d)	29.40	32.77	23.22
utilization rate (%)	95%	106%	75%
Δ in feed rate (%)	——	11%	-21%

Current crude rate is the 2010–2012 avg. of data from Rail Spur RDEIR at 2-35; SMF projects crude rate is the proposed Throughput Increase. (Id.) 'No SMF projects' crude rate is from the median year-2045 forecast illustrated in Figure 1 and the conservative assumption that all crude produced by Central Coast OCS, state offshore and onshore oil fields now identified as SMF suppliers will be supplied to the SMF (other plants received 45% of total production from these oil fields during 2010–2012). SMF naptha and gas oil supplied to Rodeo are throughputs reported by the SLOAPCD emission inventory, for all SMF plant naphtha and gas oil product tanks. This SLOAPCD data appear reasonable based on design performance and measurements of similar processes and crude slates as those at the SMF. Rodeo 2014 capacities in b/cd from USEIA (http://www.eia.gov/petroleum/data.cfm); Rodeo feed rates are multi-year averages from SFRWQB NPDES Order R2-2011-0027. Scenario feed rates are based on changes in gas oil (HCU) or naphtha (CRU) feed rate.

** Effects of LPG-rich diluents and harder-to-crack bitumen in tar sands dilbits (not shown in the table) would greatly boost LPG-per-barrel processed in the 'SMF projects' scenario.

for these high-value products—and yield significant amounts of propane and butane in this process. The gasoline stream (naphtha) must also be 'reformed' to boost octane rating, and thus is processed via catalytic naphtha reforming at the RF. The table shows changes from current (2010–2012) conditions in both scenarios identified above.

33. As stated, available evidence indicates insufficient currently recoverable LPG, and estimates based on publicly verifiable data for LPG known to be recoverable with available technology indicate that roughly half of Phillip's proposed LPG recovery capacity would be idle in these 'baseline' conditions. (See Paragraph 16.) Implementing the SMF throughput increase and rail components, however, would boost its naphtha and gas oil deliveries to Rodeo by ≈29% and boost *total* RF gas oil hydrocracking by ≈11%. See Table 1. Because hydrocracking is a significant LPG producer, LPG available for recovery at the RF would increase proportionately more than this 11%. Recoverable LPG would increase still more from the additional coking (not shown) of 29% more crude feed and, given that tar sands dilbits are the most likely new crude feed, from the LPG-rich diluents in these dilbits. (See Fox comments.) The sum of these increments could boost recoverable LPG at Rodeo from roughly 50% to more than 70% of the proposed project's design capacity.

34. In the 'No SMF projects' scenario, SMF crude throughput would rely on terminally declining local/regional crude supplies and would decline as illustrated in Figure 1. A conservative (less steep) estimate of this decline and its effects on processing is described in Table 1 (see caption), for the time frame roughly around 2045, which is within the project duration (see paragraph 21). SMF-to-RF naphtha and gas oil volumes drop by about half and *total* RF gas oil hydrocracking drops by ≈21%. This is a conservative estimate; if it does not replace its already-declining crude feedstock supply by then, the SMF might more likely be shut down by 2045. (See Figure 1.)

35. The RDEIR's revised estimate of currently recoverable LPG suggests a small shortfall below the project design basis, ranging from 10–31% of project capacity being idled, depending upon the averaging period chosen. (See Paragraph 16.) This estimate is not supported by publicly verifiable data and overestimates recoverable LPG by applying maximum conditions as average ones and including LPG streams that are not feasible to recover in its 'recoverable' estimate. (Id.) Even if the RDEIR's overestimate is assumed, however, the 21% reduction in gas oil hydrocracking in the 'No SMF projects' scenario and the further LPG supply losses from idled coking and distillation capacity at the SMF could reduce LPG at the RF enough to idle roughly 40–50% of the proposed project capacity. Thus, the project cannot be implemented as proposed in the 'No SMF projects' scenario. Therefore, the Rodeo LPG component of the project depends upon the SMF throughput increase and crude by rail components for feedstock.

36. Importantly, an otherwise unexplained change in the project description is informed by the 'current conditions' and 'SMF project' results for naphtha in Table 1. Naphtha from the Rodeo heavy gas oil hydrocracker (Unit 246) and the ULSD diesel hydrotreater (U250) is routed through the proposed new 'fuel gas' hydrotreater in Revised Figure 3-6 of the RDEIR. These streams were routed through the proposed LPG recovery but *not* the proposed new hydrotreater in Figure 3-6 of the June 2013 DEIR. Further, these U246 and U250 streams are 'wild naphtha' derived at least in part from processing the SMF gas oil ('SMGO;' see Figure 3-4.[51]) Finally, these wild naphtha streams are now fed through other processes to reforming units U231 and U244 (see Figure 3-4), but revised Figure 3-6 shows the project re-routing them to naphtha blending instead. In sum, these naphtha streams are fed to the Rodeo reformers now but the revised LPG recovery proposal would instead route them through the new hydrotreater. For convenient review, RDEIR Revised Figure 3-6, RDEIR Figure 3-4, and original Figure 3-6 from the June 2013 DEIR are excerpted below.

37. The 'current conditions' and 'SMR projects' results for naphtha reforming in Table 1 are relevant to this project revision because they show that the Rodeo reformers are currently near maximum capacity (95% of 31.0 Mb/d) and would violate this maximum capacity limit if the SMF project components are fully implemented (106% of capacity). Further, the estimate in Table 1 probably underestimates this problem by conservatively assuming none of the expected further increase in naphtha inputs from the diluent in tar sands dilbits, though the throughput increase cannot be implemented without the rail spur, which would most likely tap these price-discounted and LPG-rich oil feeds. In any case, the units probably could not run properly, efficiently *and* safely if run beyond maximum capacity on a sustained basis, and either selling low-value unfinished naphtha into the new shale oil-dominated crude market at a deep discount, or cutting crude rate because of this limitation, could be costly. It also would mean that the throughput increase project could not be fully implemented. Routing some of the naphtha from the SMF to the new hydrotreater instead would relieve the bottleneck while allowing those streams to be part of the finished product slate—and that is what the LPG project revision described in paragraph 36 would do. Thus, the LPG component of the project enables full implementation of the SMF components.

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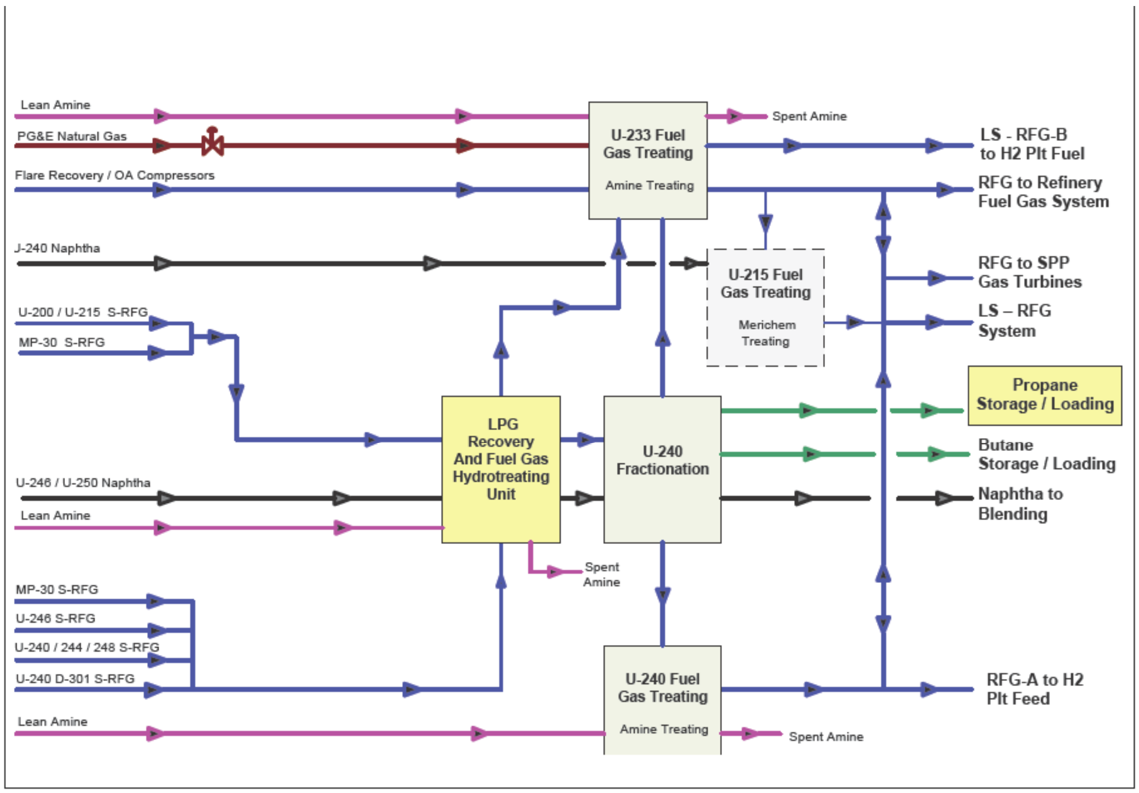
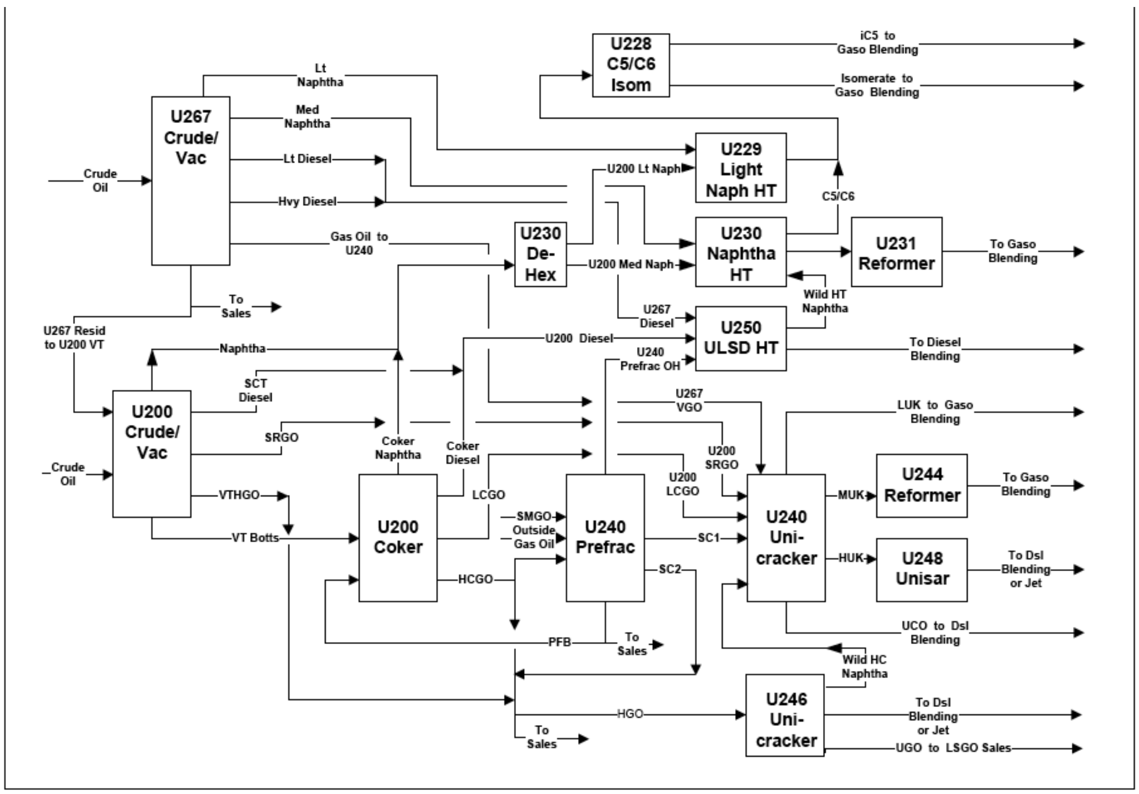
[51] *See* also the comments of Phyllis Fox regarding the 'Propane Recovery' DEIR.



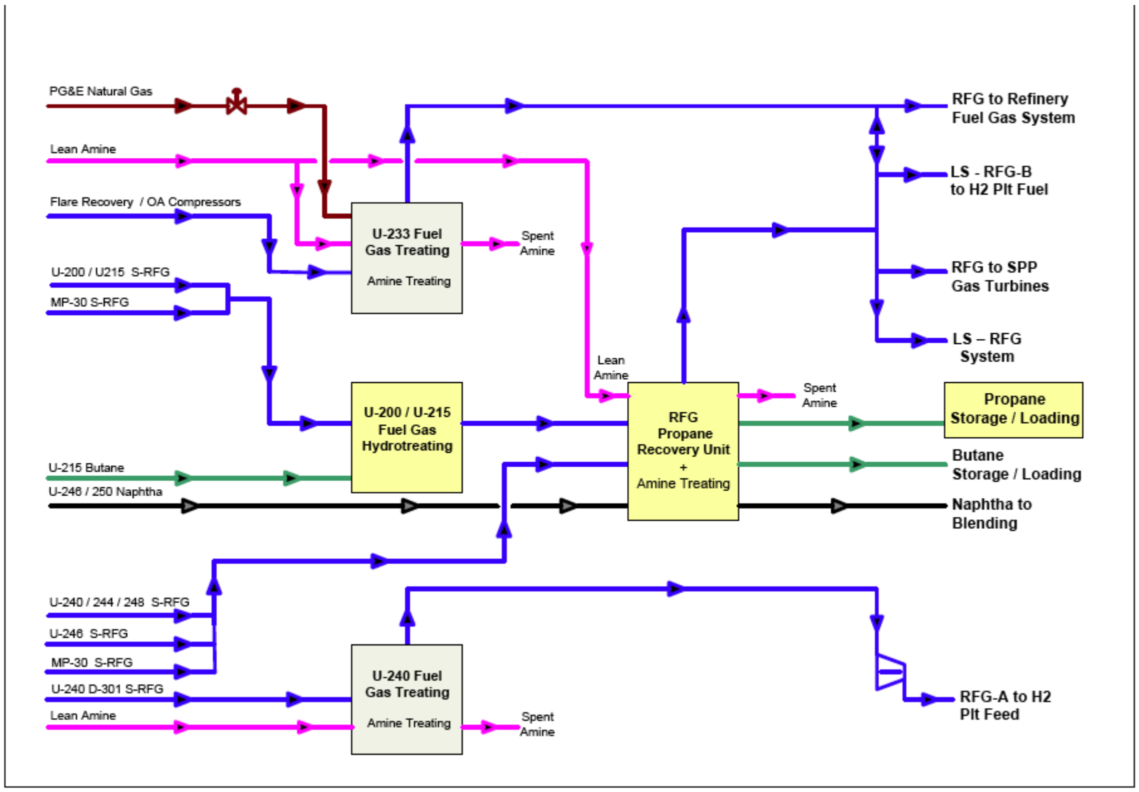
SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-6 Revised
Proposed Refinery Fuel Gas System Block Flow Diagram



SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-4
Overall Block Flow Diagram of Refinery



SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546

Figure 3-6

Proposed Refinery Fuel Gas System Block Flow Diagram

38. As discussed in paragraphs 25–37, the San Francisco Refinery's proposed 'projects' in Santa Maria and Rodeo are inextricably interrelated. The Santa Maria throughput increase is dependent upon the crude by rail proposal, the Rodeo LPG recovery/hydrotreater proposal is dependent upon those Santa Maria components, and those throughput increase and crude by rail components are dependent upon the new Rodeo hydrotreater for full project implementation. Therefore, the crude throughput rate increase, crude by rail, and LPG recovery proposals are interdependent parts of a single project of larger scope that has been piecemealed.

39. The failure to evaluate this project as a whole results in underestimating the scope and severity of identified impacts. The greater climate-disrupting emissions, toxic air contaminant emissions, smog-forming emissions, and safety hazards of project crude oil trains to the SMF *and* LPG trains from Rodeo, in combination and on many of the same routes, are examples of this underestimation. It further results in failure to identify some impacts at all, such as the toxic, smog-forming, and climate-disrupting emissions from refining larger volumes of crude feedstock, and those from switching to processing of bitumen oils. These 'tar sands' oils are extremely dense, refractory and contaminated and require substantially more energy, and fuel combustion for that energy, per barrel refined, thereby greatly boosting refinery emissions intensity and process safety hazard.[52] Equally important, evaluating the project only one piece at a time results in failure to identify feasible means to lessen or avoid impacts. For example, the switch to tar sands oil that is clear when the project is viewed as a whole would result in significant potential impacts from *refining* (in addition to the project's significant potential impacts along the mainline rails). Thus, the County clearly *can*—and indeed, *should*—consider choosing to demand that Phillips 66 refrain from the most dangerous and polluting type of oil known. But the RDEIR mentions no such mitigation. In short, the piecemealing of this project is a fundamental flaw in the RDEIR.

[52] My previous comments found the reasonable potential that this project-related feedstock switch could result in significant potential catastrophic hazard, air quality, public health, and climate impacts. (Karras Rodeo Report-1 at paragraphs 56–83.)

Project Impacts

40. All of the potential impacts associated with the changes in oil feedstock at the SFR's SMF and RF and the changes in the oil and LPG rail transport to and from these facilities that are identified in my comments[53] and those of Dr. Fox are also cumulative impacts of Phillips' throughput increase, crude by rail, and LPG recovery proposals. The RDEIR's failure to disclose, evaluate, or mitigate these potential impacts is unsupported and inappropriate, as discussed in paragraphs 12–39.

41. CBE learned of Kinder Morgan's new crude by rail terminal in Richmond following my previous comments in this matter. This terminal is adjacent to the Port of Richmond and aligned with rail routes that the project would be expected to use for LPG transport from the RF and crude transport to the SMF.[54] A map of the mainline routes from Roseville through Rodeo, Richmond and other Bay Area communities on the way toward the SMF is excerpted from the Rail Spur RDEIR below. The RDEIR does not include this terminal in its cumulative impact analysis,[55] does not say whether crude delivered by rail to the SMF might be loaded at this terminal, Richmond's port, or both, and does not appear to mention the Kinder Morgan crude by rail terminal at all.[56]

42. Phillips' proposal and route for diluted bitumen by rail to the project are now revealed more clearly. (See paragraphs 19–23; Rail Spur RDEIR at 4.13-9.) Bitumen poses a different and more severe spill hazard for water quality and aquatic life than conventional crude. It is denser than water and sinks to the bottom when spilled into water. Aquatic remediation by surface skimming does not work on these tar sands oil spills; they are effectively impossible to 'clean up,' worsening aquatic spill impacts. Compounding the hazard, the project would bring crude oil trains through the unique aquatic habitats of the San Francisco Bay/Delta. (See map, next page.) There is a reasonable potential that this could result in significant impacts to Bay/Delta ecosystems from tar sands oil spills in derailments of project-bound crude oil trains. The RDEIR does not disclose or address these potential impacts of the project on the Bay/Delta.

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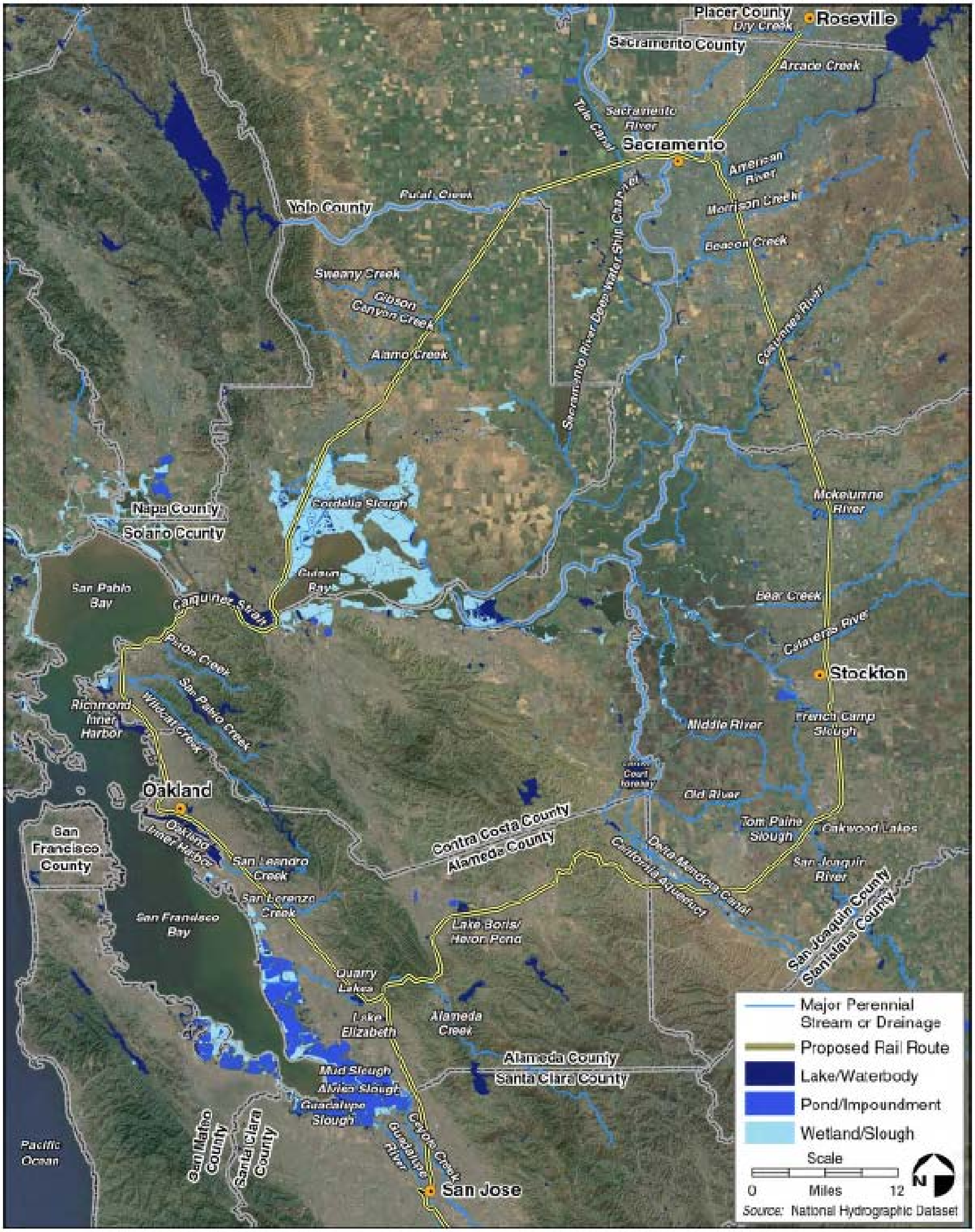
[53] My previous comments found the reasonable potential that these project-related changes in oil feedstock could result in significant potential catastrophic hazard, air quality, public health, and climate impacts. (Karras Rodeo Report-1 at paragraphs 56–83.)
[54] *See* RDEIR at 4.3-9 and 4.3-10; Rail Spur RDEIR at 4.13-9.
[55] *See* RDEIR Table 5-1.
[56] A search of the RDEIR on "Kinder Morgan" returned a "no matches were found" result.

Figure 4.13-5 Mainline Route Water Bodies, Roseville to San Jose



43. Garbage in–garbage out errors continue to plague the Health Risk Assessment (HRA) in the RDEIR. In one example that is a fatal flaw in the HRA by itself, the emissions estimates used in the HRA drastically underestimate potential emissions associated with the project. Failing to disclose and analyze emissions associated with the project-related change in crude feedstock discussed in paragraphs 12–40, the RDEIR excludes those emissions from its estimate, drastically underestimating the project's emission potential for multiple pollutants. Using those erroneously lower emissions estimates as inputs to the HRA forces the health impact results calculated for those emissions by the HRA to be erroneously less severe that the true project potential.

44. Interpretative problems still plague the HRA in the RDEIR as well. For example, despite the drastic underestimation discussed in paragraph 43, the RDEIR reports a per-million people cumulative cancer risk from exposures to toxic air contaminants for the project of ≈61/MM. (RDEIR at 4.1-34.) Impact screening thresholds for such general population involuntary exposures have generally ranged widely, from 1/MM to 100/MM, with most air districts in California using 10/MM to 20/MM. Also, the Air District using 100/MM has publicly disavowed this outlier threshold as potentially under-protective.[57] The RDEIR, however, picks the 100/MM threshold without mentioning all of the more health-protective ones or that its choice has been disavowed, and concludes on that basis that the impact is 'less than significant.' (RDEIR at 4.1-14, 4.1-31, 4.1-34.) A more reasonable interpretation would reject the disavowed outlier in favor of a less extreme threshold, and note that the 61/MM HRA result exceeds it, indicating that the project has the reasonable potential to contribute to a significant cumulative air toxics impact.

45. The RDEIR's revised analysis of greenhouse gas (GHG) emissions fails to explain how—if offsite emissions from the project's LPG sales are too speculative to estimate as it claims—it can estimate them at a level of zero, particularly when this transforms a significant impact finding into a less-than-significant finding. (RDEIR at 4.5-13/14/15.)[58] This issue was addressed in my previous comments. An emission range

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[57] _See_ Staff presentations to the BAAQMD Board regarding the Petroleum Refinery Emissions Tracking Rule and Office of Health Hazard Assessment Update, Oct–Nov 2014.

[58] The RDEIR's estimate of zero metric tons per year emitted from the propane and butane sold and portion of that burned offsite is mathematically incontrovertible. _See_ table on page 4.5-15: Subtracting the emissions caused by burning all of this LPG onsite (708,858 Mt/y) from those caused by burning the natural gas replacing that LPG onsite (592,792 Mt/y) yields a difference of –116,066 Mt/y, which is equal to the table's "net fuel source transfer combustion emissions." This equivalence (zero difference) proves the RDEIR estimates 0 Mt/y offsite LPG emissions.

could be estimated, and any credible estimate of offsite emissions from project sales of these LPG fuels must admit at least 10% of them could potentially be burned, which would reveal a significant impact. (See RDEIR Table 4.5-3.)

46. A project revision that appears to broaden the uses of the proposed expansion of once-through cooling (OTC)[59] emphasizes the point that this OTC expansion would be oversized for the project heat sources disclosed, and the question of whether that excess capacity is needed for heat from processing the project's changing oil feedstock. My previous comments raised this point and question.[60] The RDEIR's admission that the OTC expansion would be operated to boost heat discharge in proportion to Bay cooling water flow (RDEIR at 4.7-23), and its additional project revision to route naphtha produced in part from SMF oil feeds to Rodeo (paragraphs 10, 36–38), further emphasize this point and question. But the RDEIR continues the DEIR's failure to disclose the sources of this excess heat and their contributions to the excess, even as it changes the project description to broaden and further obscure this part of the project description.

47. My previous comments found that the DEIR underestimated project OTC impacts substantially by overestimating current average flow based on the erroneous assumption that a single recent year accurately represents current conditions, and provided detailed data supporting those findings. (Attachments 1 and 2.) I also noted that past monitoring of environmental conditions at lower OTC flow does not by itself predict impacts of the much greater proposed cooling water and heat flows. (Id.) Unfortunately, the RDEIR's revised discussion reasserts the same inflated OTC baseline and erroneous claim that a single recent year accurately represents current average conditions, fails to include any actual data supporting those assertions, and still relies on monitoring of past Bay conditions at lower OTC flows to predict project impacts.[61] The publicly verifiable data in the record (which the RDEIR thus ignores) indicate that instead of the 25% increase suggested by its inflated baseline, the project could increase OTC flow by 40–65%. (See Attachment 2.)

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[59] RDEIR at 3-37 vs. DEIR at 3-27; *see* also Paragraph 11.
[60] Attachment 1 at paragraphs 27–30.
[61] RDEIR at 4.2-27 through 4.2-29, 4.7-22 and 4.7-23. *See* esp. 4.7-22 (baseline assertions) and 4.2-29 and 4.7-23 (reliance on past monitoring). *See* also 4.2-29 (the size and dispersal of the impact plume is "primarily driven by tides *and output temperature and volume* [*emphasis added*]) and 4.2-27 (RDEIR analysis excludes impacts associated with effects on eggs and larvae of aquatic species that are not already listed as threatened or endangered).

48. The RDEIR's revised OTC discussion also asserts: "In 2005, the Refinery became the first company in California to successfully operate a wedgewire screened intake in a saltwater environment." (RDEIR at 4.2-28.) Strangely, the RDEIR omits mention of a more salient singularity: Phillips 66 is the only refiner that still exploits the San Francisco Bay/Delta by using once-through cooling.[62] The omission truncates the RDEIR's evaluation, obscuring facts about the environmental setting that would reveal additional impacts from the proposal to extend the operating duration of this antiquated technology and the feasibility of avoiding OTC impacts entirely as other refiners have done already. Moreover, the revelation that by extending OTC operation the project would cause impacts from the entire OTC flow exposes the fallacy of the argument that replacing OTC has no nexus to the project,[63] and further shows that the RDEIR's failure to analyze this alternative is unreasonable.

49. CBE has learned that, following my previous comments in this matter and the County's request for "Inherently Safer System study for the new process including storage and loading operations that includes the evaluation of alternatives listed in the Draft EIR"[64] Phillips 66 did perform that Inherently Safer System (ISS) analysis.[65] Crucially, the County's request for ISS analysis including "alternatives listed in the Draft EIR" referred to cooled storage—which may be inherently safer than the pressurized storage of LPG proposed, with respect to the specific hazard of catastrophic explosion (BLEVE). Proper ISS analysis would be based on Process Hazards Analysis (PHA), the rigorous analysis of process systems upon which current industrial safety practice relies, and ISS is an indispensable layer of protection that is higher in the hierarchy of safety controls, reflecting its importance. (<u>See</u> Chemical Safety Board, 2013.)[66] Thus, project-

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[62] <u>*See*</u> Attachment 1 at paragraphs 31 and 32. The two points are related: the intake screens were installed at the refinery *instead of* replacing OTC and even after this half measure was installed water quality officials required Phillips to investigate replacing OTC at Rodeo. (<u>Id</u>.)

[63] <u>*See*</u> RDEIR at 6-6 (closed loop cooling alternative to OTC not analyzed in RDEIR; analysis of alternative to OTC "for the Project's <u>*additional cooling needs only*</u>" [<u>*emphasis added*</u>]; this alternative "was not considered practical" and "was not considered further").

[64] 11 July 2013 letter from Michael Dossey, Accidental Release Prevention Engineer, Contra Costa Health Services, Hazardous Materials Programs, to Jim Ferris, Health and Safety Superintendent, Phillips 66 San Francisco Refinery, re; *Phillips 66 Propane Recovery Project (County File #LP12-2073).*

[65] Per. Comm. with Michael Kent, Hazardous Materials Ombudsman, Contra Costa County Health Services. 4 Dec 2014.

[66] U.S. Chemical Safety Board (CSB), 2013. *Interim Investigation Report: Chevron Richmond Refinery Fire; Chevron Richmond Refinery, Richmond, California, August 6, 2012.*

specific ISS analysis is essential to adequate evaluation of project hazards and the specific question of whether cooled instead of pressurized LPG storage is a safer alternative. My previous comments addressed this issue, noting the need for ISS analysis to be included in this CEQA review, and that the DEIR's concerns over costs of electricity and a new flare were misplaced, as there is no such cost exemption for otherwise feasible ISS.[67] Despite the reported availability of the ISS analysis to the County, the RDEIR still dismisses this alternative from further consideration based on exactly the same cost concerns expressed in the same words (RDEIR at 6-5 and 6-6), and it still does not include, disclose or even discuss this ISS analysis. (As CSB investigation reports demonstrate, this level of process safety detail can be released publicly without abridging confidentiality concerns.) This failure to disclose available information that is needed for an informed project decision about safety in the RDEIR appears improper.

50. Potential impacts of the change in hydrogen plant feedstock that is indicated by the RDEIR's revised project description (see Paragraph 9) are not analyzed or even discussed in the RDEIR's text. Hydrogen production is a major GHG emitter, and RF hydrogen plant process upsets, shutdowns for required maintenance, and shutdown/ startup design requirements are reported in BAAQMD Rule 12-12 causal analysis reports as recurrent causal factors in environmentally significant flaring at Rodeo.

51. An old issue merits critical attention. Potential benefits from reducing sulfur dioxide emissions by half, while that is achievable and important to achieve, could be unrealized if Phillips' and BAAQMD's stated plan[68] to proceed with emission reduction credits (ERCs) for this emission cut is not addressed. ERCs are a type of 'pollution trading' that could allow Phillips to increase those emissions again. I commented previously on this problem and suggested that the "County could consider developing a land use permit condition that ensures the 50% reduction in refinery wide SO_2 emissions identified in the DEIR will be real, measurable and permanent."[69] The RDEIR proposes no such measure. The RDEIR's assertion that this ephemeral emission reduction is a benefit of the project without addressing the foreseeable plan to potentially cancel out that claimed benefit through pollution trading is inaccurate and misleading.

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[67] Attachment 1 at paragraphs 39–44, 49, and 50.
[68] Air Permit Application at 17, Section 3.4 (Permit App Sections 1–3); and Per. Comm. with Jim Karas, BAAQMD at 4 Dec. 2013 Board Meeting (BAAQMD advised Phillips 66 to defer its ERC application and proceed with this step after project approval).
[69] Karras Rodeo Report-1 at paragraphs 26, 54.

Conclusions

52. Based on my knowledge, experience and expertise and the data, information and analysis discussed in this report, in my opinion:

- Project-related changes in San Francisco Refinery (SFR) oil feedstock sources, quantity, and quality are not disclosed in the RDEIR.
- The project would enable substantial changes in SFR oil feedstock sources, quantity, and quality and would most likely shift the SFR to refining fundamentally different 'tar sands' oils.
- The description of the project scope in the RDEIR is truncated, inaccurate, and misleading.
- Proposed LPG recovery and hydrotreating at the Rodeo Facility, crude throughput increase at the Santa Maria Facility, and crude by rail unloading at the Santa Maria Facility are inextricably related, interdependent components of a single project of larger scope that has been piecemealed.
- The project as revised in the RDEIR still has the reasonable potential to cause the significant adverse hazard, air pollution, public health, aquatic habitat destruction, and climate impacts identified in my prior comments in this matter, and the RDEIR does not identify, mitigate, or otherwise address adequately these significant potential impacts.
- The project has the reasonable potential to result in significant impacts that the RDEIR does not identify, mitigate, or otherwise address from oil spills in derailments resulting from project crude oil transport by rail across the San Francisco Bay/Delta.
- The project has the reasonable potential to contribute substantially to cumulative impacts that the RDEIR does not identify, mitigate, or otherwise address adequately.
- The RDEIR does not include adequate information about the project to identify other potential impacts, such as those associated with changes in hydrogen plant feedstock, although these impacts may be significant.
- The RDEIR does not include the information necessary to understand and evaluate the environmental implications of the project. It did not describe the duration, setting, geographic or processing scope, feedstock, operation, or potential environmental effects of the project accurately or, in many cases, did not describe them at all. These informational deficiencies are so profound, and the revisions needed to cure them so extensive, that full independent review of a comprehensively revised draft would be necessary before public decisions could be based with confidence on this project's environmental review.

53. I have given my opinions on these matters based on my knowledge, experience and expertise and the data, information and analysis discussed in this report.

I declare under penalty of perjury that the foregoing is true of my own knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

Executed this **_5th_** day of December 2014 at Oakland, California

Greg Karras

Comments

on the

Draft Environmental Impact Report (DEIR)

for the

Valero Benicia Crude by Rail Project

Benicia, California

September 15, 2014

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I have reviewed the Draft Environmental Impact Report (DEIR)[1] for the Valero Benicia Crude by Rail Project (CBR Project) prepared for the City of Benicia (City) by ESA, as well as records referenced in the DEIR and files obtained from the Bay Area Air Quality Management District (BAAQMD).

The CBR Project will install facilities to allow the Valero Benicia Refinery (Refinery) to receive up to 70,000 barrels per day (bbl/day) of North American crude oils by rail. The facilities that would be installed include about 8,880 feet of new track; a new tank car unloading rack capable of unloading two parallel rows of tank cars simultaneously; and 4,000 feet of 16-inch diameter crude oil pipeline and associated fugitive components (valves, flanges, pumps) connecting the offloading rack and an existing crude supply pipeline. DEIR, pp. ES-1 to ES-4.

Based on my review, I conclude this DEIR is fundamentally defective in that it omits crucial information to understanding the Project's significant impacts. Specifically, the DEIR does not disclose the Project's crude slate, relies on flawed analyses in addressing whether the Project would enable refining of substantial quantities of tar sands and Bakken crudes, relies on unsupported assumptions as to the Project's light crude composition, and underestimates the Project's operational emissions of reactive organic gases ("ROG") and toxic air contaminants ("TAC"). When these underestimates are corrected, the CBR Project results in significant air quality and public health impacts. The City must correct these defects and recirculate the DEIR, so that the public and decision-makers can be fully informed of the Project's air quality and public health and safety impacts.

My resume is included in Exhibit A to these Comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution control; greenhouse gas (GHG) emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; hazard investigations; risk of upset modeling; environmental permitting; nuisance investigations (odor, noise); environmental impact reports, including CEQA/NEPA documentation; risk assessments; and litigation support.

I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. 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.

[1] ESA, Valero Benicia Crude by Rail Project, Draft Environmental Impact Report, SCH # 2013052074, Use Permit Application 12PLN-00063, June 2014.

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. This work includes Environmental Impact Reports (EIRs), Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries; crude oil and rail terminals in California, Louisiana, Oregon, New York, Texas, and Washington; and various other permitting actions for tar sands and light shale crude refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas and liquefied natural gas (LNG) facilities in Texas, Louisiana, and New York.

My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (2001) 111 Cal.Rptr.2d 598 and *Communities for a Better Environment v. South Coast Air Quality Management Dist.* (2010) 48 Cal.4th 310.

I commented on the Initial Study/Mitigated Negative Declaration (IS/MND) (attached to the DEIR as Appx. A[2]) that the CBR Project would allow a change in crude oil slate quality, to heavier higher sulfur crudes and/or to lighter sweeter crudes, which would result in emission increases that were not considered in the CEQA review. Fox IS/MND Comments[3], pp. 2-35. The DEIR does not correct the defects that I identified in my IS/MND comments. Rather, it advances an argument that the rail-imported crudes will be blended with other crudes to meet the same sulfur and weight specifications as in the baseline Refinery. Thus, the DEIR asserts that crude slate quality and emissions from refining it would not change. This is incorrect. This does not address my comments on the IS/MND. Therefore, I reassert my IS/MND comments and incorporate them here by reference. The following sections present my evaluation of the DEIR's response to my previous crude slate switch comments, point by point. The DEIR's response to my comments is included in Appendices C.1 and C.2, based on a report contained in Appendix K. The following comments on Appendices C.1 and C.2 apply equally to the underlying analyses in Appendix K.

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[2] ESA, Valero Crude by Rail Project, Initial Study/Mitigated Negative Declaration, Use Permit Application 12PLN-00063, Prepared for City of Benicia, May 2013.

[3] Phyllis Fox, Comments on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063, July 1, 2013; http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf.

I. THE DEIR FAILS TO ANALYZE THE AIR QUALITY IMPACTS FROM REFINING DIFFERENT TYPES OF CRUDE

A. Heavy Sour Crudes

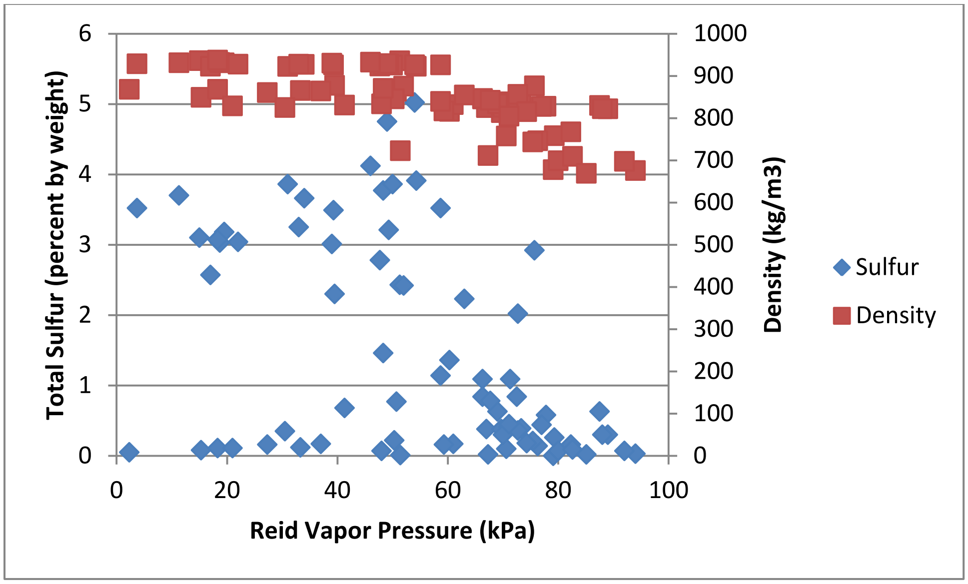
The CBR Project DEIR responds to the heavy sour crude slate issues that I raised in Appendix C.1. The thrust of the CBR Project DEIR's response is based on the "weight" (API gravity)[4] and sulfur content of the crude, which it argues would not change due to the Project, but rather would remain within a narrow range. Therefore, the CBR Project DEIR argues, emissions would not increase. The CBR Project DEIR argues: "Thus, to the extent that the Project would cause an increase in emissions based on an increase in the weight and sulfur content of crude feedstocks – any such emissions increase would be within the baseline environmental conditions." DEIR, Appx. C.1, p. C.1-3.

First, this misses the point, as explained in my previous comments at Section II.D, pp. 19-31. There are important differences between crudes that are not related to the weight and sulfur content of the crude that result in adverse impacts. Even if the weight and sulfur content of a particular crude blend fall within the range specified in the DEIR, or don't change at all, other components in the crude, such as TACs like benzene, or highly malodorous compounds such as mercaptans, may be present at much higher concentrations than in the crudes they replace with identical sulfur and API gravity.

Further, other characteristics of the crude, such as its vapor pressure or flammability, may differ in significant ways from the crudes they would replace. These other constituents and properties are not a function of the API gravity or the sulfur content and are present independent of them. The DEIR's consultant, Dr. McGovern, demonstrated there is no relationship between vapor pressure (expressed as RVP) and crude gravity (expressed as API). DEIR, Appx. K, p. K-18. This is further substantiated by analysis of data published by Enbridge, summarized here in Figure 1. The Enbridge data covering 76 different types of crude oil show that crude oil attributes of sulfur content and density are completely independent of vapor pressure.

[4] Note that throughout the DEIR, the term "weight" is used to indicate API gravity or density, where "density" is technically what is meant. We will use the same terminology in this report; "weight" indicates density.

Figure 1: Reid Vapor Pressure Compared to Total Sulfur and Density for 76 different types of Crude Oil



Source: Enbridge Pipelines Inc., 2013 Crude Characteristics, http://www.enbridge.com/~/media/www/Site%20Documents/Delivering%20Energy/2013%20Crude%20Characteristics.pdf

The vapor pressure of crude determines to a large extent the amount of ROG and TAC emissions that are emitted when it is transported, stored, and refined. Thus, a crude slate may have identical sulfur content and weight, but would result in dramatically different ROG and TAC emissions. Similarly, the nature of the chemical bonds in crude determines the amount of energy and hydrogen that must be supplied to refine it. Thus, a crude slate may have identical sulfur and weight, but a different mix of chemicals that would affect the amount of energy and hydrogen required to convert it into refined products.

These differences—in both chemical and physical characteristics other than API gravity and sulfur content— fluctuate independent of sulfur content and API gravity and will result in significant impacts that have not been considered in the DEIR. These impacts include, for example, significant increases in ROG emissions, contributing to existing violations of ozone ambient air quality standards; significant increases in TAC emissions, resulting in significant health impacts; significant increases in malodorous sulfur compounds, resulting in significant odor impacts; significant increases in combustion emissions, contributing to existing violations of ambient air quality standards; and significant increases in flammability and thus the potential for more dangerous accidents involving train derailments or spills on-site. The DEIR fails to consider these significant impacts by raising irrelevant issues.

Second, the rationale that sulfur levels and density of the crude slate would stay within a narrow range ignores the possibility of gradual creep within that range that would still be significant. This recently occurred at the nearby Chevron Richmond Refinery. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit.[5] This change increased corrosion rates in the 4-sidecut line, which led to a catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This accident sent 15,000 people from the surrounding area for medical treatment due to the release and resulting fire that created huge black clouds of pollution over the surrounding community. Fox IS/MND Comments, pp. 25–26.

These types of accidents can be reasonably expected to result from incorporating tar sands crudes into the Benicia crude slate, even if the range of sulfur and gravity of the crudes remain the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high total acid number (TAN) and high solids, which aggravate corrosion. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from tar sands crudes, leading to catastrophic releases.[6] Fox IS/MND Comments, pp. 35-36.

Catastrophic releases of air pollution from these types of accidents were not considered in the DEIR. Rather, the DEIR relies on the Refinery's existing Process Safety Management program, including the Management of Change (MOC) and Mechanical Integrity (MI) programs, to prevent corrosion. DEIR, p. 3-16. However, these programs were also in place at Chevron at the time of the August 2012 accident discussed above, and they did not prevent a catastrophic accident caused by sulfur creep. The recent Chevron FEIR incorporated many additional mitigation measures to improve these programs,[7] which should be required for the Valero Rail Project.

Third, the unloading rack, storage tanks and associated fugitive components are major sources of the ROG and TAC emissions. These unload, transport, and store crude oil as delivered, before it is blended. Therefore, the argument that the rail-imported crude is blended before it is refined is irrelevant.

[5] US Chemical Safety and Hazard Investigation Board, Chevron Richmond Refinery Pipe Rupture and Fire, August 6, 2012, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").

[6] See, for example, K. Turini, J. Turner, A. Chu, and S. Vaidyanathan, Processing Heavy Crudes in Existing Refineries. In: Proceedings of the AIChe Spring Meeting, Chicago, IL, American Institute of Chemical Engineers, New York, NY, Available at: http://www.aiche-fpd.org/listing/112.pdf.

[7] See, for example, Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1& 2, p. 4-40, Mitigation Measure 4.13-7h, Available at: http://chevronmodernization.com/project-documents/.

1. The CBR Project DEIR Must Evaluate the Potential Impacts of the Full Range of Crude Oil Types That Could Be Imported

The CBR Project DEIR asserts: "There is no reason to believe that…Valero would be more likely to purchase heavy Canadian crudes than any number of other North American crudes that are lighter and/or sweeter…" DEIR, Appx. C.1, p. C.1-1. The CBR Project DEIR presents a table that lists 38 "available North American crudes" that could potentially be imported by the proposed rail facilities. DEIR, Table 3-1. Of these 38 crudes, 87% or 33 of them, are Canadian tar sands crudes and of the tar sands, 15 are "heavy sour" and 5 are "medium sour." Canadian tar sands crudes are chemically distinct from the current crude slate and thus will result in significant impacts that were not analyzed in the CBR Project DEIR. Fox IS/MND Comments, pp. 25-28. DEIR Table 3-1 is prima facie evidence that tar sands crudes are likely to be in the mix of crudes that will be imported by the CBR Project.

Regardless of which of these 38 crudes is selected, the DEIR must analyze the full range of resulting impacts, from all of the 38, as the DEIR suggests all or any of them may be refined. Impacts would vary greatly between tar sands crudes on the heavy high sulfur end and by Bakken crudes on the light sweet end, each end of this range with unique and significant impacts. The DEIR does not include impacts from either of these, but rather only an unidentified default crude that is not representative of any of the 38. See Comment III.

2. Blended Weight and Sulfur Content Do Not Determine ROG and TAC Emissions

The CBR Project DEIR argues that "even if Valero were to purchase large amounts of heavy sour Canadian crudes as a result of the Project, this would not cause an increase in refinery emissions because Valero must blend crude feedstocks to a narrow range of weight and sulfur content before processing them." DEIR, pp. 3-14, 3-24, 4.1-17, C.1-1/2. This is insufficient information to analyze impacts, as noted above, because the weight (API gravity) and sulfur content are not the only characteristics of crude oil that determine environmental impacts. Other important factors include volatility, flammability, metal content, ROG speciation profile, the specific suit of heavy organic compounds in the crude, and the TAC and sulfur speciation profile (i.e., the concentration of individual TAC and sulfur compounds present in the crude).

Elevated levels of benzene or hydrogen sulfide, for example, cannot be blended out because they are emitted from tanks and fugitive components before the crudes reach the mixing tanks. The majority of the toxic TACs and malodorous chemicals are emitted before blending occurs, during unloading and from fugitive components along the pipeline and at the storage tanks. Blending by itself does not eliminate them.

Similarly, elevated metals that end up in coke fugitive particulate emissions cannot be blended out. No matter how much blending is done with relatively less contaminated crudes, a significant amount of heavy metals from lower quality rail-imported crude would still remain, mostly partitioning to the coke. Blending also does not remove but only dilutes elevated concentrations of high molecular weight organic compounds such asphaltenes and resins that require high energy input to break down into marketable products. Fox IS/MND Comments, pp. 4-10. These characteristics may vary in significant ways among crudes with the same range of API gravity and sulfur, resulting in significant environmental impacts. Fox IS/MND Comments, pp. 29-30.

3. <u>Crude Slate Impacts Are Not Part of the Baseline</u>

The CBR Project DEIR indicates that Valero made significant modifications to the Refinery between 2004 and 2010. These modifications are collectively known as the "Valero Improvement Project" or VIP. The City certified the VIP project EIR and approved the VIP project in April 2003. It later certified the VIP EIR addendum in July 2008. DEIR, p. 3-12.

The CBR Project DEIR argues that crude slate impacts are part of the VIP baseline, "[e]ven if refinery emissions were to increase based on Valero's purchase of heavy sour Canadian crudes, any such emissions increases would properly be considered part of the baseline because the baseline includes the full scope of operation allowed under existing permits that were issued based upon prior CEQA review." DEIR, p. C.1-1. The DEIR cites several CEQA cases regarding subsequent environmental review for modifications to existing projects.

Setting aside legal considerations, this argument has no technical merits for three reasons. First, the scope of operations previously approved did not include any impacts from a crude slate change and did not contemplate the crudes listed in DEIR Table 3-1. Second, the CBR Project Project is not a modification of the previously permitted VIP, which underwent CEQA review. Third, even assuming the VIP EIR evaluated a crude slate change and the CBR Project is just a modification of the VIP, both of which are false, the regulatory framework has changed, requiring additional CEQA review.

a. The Scope of the VIP Project Did Not Include Impacts from Crude Slate Change

Even if the CBR Project were simply a modification of the VIP Project, the VIP EIR did not evaluate impacts from a crude slate change. The existence of permits, absent CEQA review of the proposed change, is not determinative.

The VIP CEQA documents do not discuss cost-advantaged North American crudes, such as those in CBR Project DEIR Table 3-1. None of these crudes is evaluated, or even identified, in the VIP EIR. Thus, the impacts of refining these crudes were in no way considered or incorporated. Therefore, the CBR Project DEIR cannot rely on the VIP CEQA review to address the impacts of refining any of them. Rather, the VIP EIR proposed to import heavy sour crudes by ship. The crudes available by ship in 2002 are chemically and physically different from the crudes available by rail in 2014, over a decade later. The oil markets have changed dramatically due to the advent of fracking and the development of tar sands, all of which occurred long after the VIP EIR analyses were performed.

There are many cost-advantaged, heavy high sulfur crudes that likely were the target of the VIP analyses prepared in 2002, such as heavy sour crudes from Ecuador, Venezuela, Colombia and Iraq, which were refined at the post-VIP Refinery. Fox IS/MND Comments, Figure 1. These heavy sour crudes are distinguishable from the crudes that are currently the target of the CBR Project, which are tar sands crudes and light sweet crudes with distinct physical and chemical characteristics. DEIR, p. C.2-1. The crudes that are currently the target of the CBR Project (DEIR, Table 3-1) were not available in the marketplace in 2002 when the VIP CEQA analysis was performed and thus were not considered in prior CEQA analyses. The differences between the crudes considered in the VIP EIR and those that would be imported by the CBR Project are discussed in my July 2013 comments on the IS/MND.

There is no evidence that the VIP was designed to refine, and that the VIP CEQA review addressed, the unique impacts of refining any of the cost-advantaged North American crudes listed in DEIR Table 3-1. Further, the lynchpin of the VIP EIR, a new, bigger hydrogen plant to allow refining of more heavy sour crude, may not be built as Valero has enough hydrogen to meet its current needs. DEIR, p. 3-12. This could be due to the availability of hydrogen from another source or a change in crude slate to lighter crudes that do not require more hydrogen to refine.

Bakken and Bakken blends with tar sands crudes, for example, would fall into this class. Further, the rail emissions assume a line haul one-way distance of 1,500 miles (DEIR, p. 4.1-22 and Appx. E.5, pdf 1197), which is consistent with Bakken crudes. There is no evidence in the record that impacts from refining this lighter, sweeter crude were considered in the VIP EIR. These impacts are discussed below in Comment I.B.

b. The CBR Project Is a New Project

The City did not treat the CBR Project as a modification of a previously permitted project in the IS/MND, but rather as a new project. Furthermore, even the DEIR refers to the VIP as a “previous” project. DEIR at 1-4. The characterization of the CBR Project as a modification of the VIP Project in the DEIR for baseline purposes improperly characterizes the projects and causes the CBR Project DEIR to underestimate or ignore real environmental impacts.

c. The Regulatory Framework Has Changed, Requiring Additional CEQA Review

Even if one hypothetically assumed that the VIP EIR evaluated the crude slate switch facilitated by the CBR Project, the regulatory and informational framework within which the CBR Project would be developed has changed dramatically, rendering the 2002 analysis obsolete. The City certified the VIP project EIR and approved the VIP project in April 2003. It later certified a VIP EIR addendum in July 2008. DEIR, p. 3-12. The Addendum incorporated a flue gas change related to the Main Stack Scrubber and added an analysis of greenhouse gas emissions. These changes do not affect any of the issues discussed here.[8]

When the VIP CEQA analysis was performed, none of the cost-advantaged crudes listed in Table 3-1 were in the marketplace. In response to ESA questions, for example, Valero responded that the CBR Project "was implemented to take advantage of land-locked North American crudes that have **recently** become available." Valero 2013,[9] p. 1 (emphasis added). As discussed earlier, these crudes are notably different from the current crude slate, in ways that are much broader than just sulfur content and weight. Thus, none of the impacts of refining these physically and chemically distinct crudes could have been anticipated and evaluated in 2002 when the VIP CEQA analysis was performed. Further, as explained in my comments on the IS/MND, the regulatory framework has significantly changed, requiring additional CEQA review even if the Project were a modification of a project that had previously undergone CEQA review. Fox IS/MND Comments, pp. 33-34.

Since the VIP FEIR was certified in 2003, new scientific evidence about the potential adverse impacts of air pollutants has become available, and in response, new guidance has been published and several federal and state ambient air quality standards have been revised. These include:

- The 8-hour state ozone standard was approved by the California Air Resources Board (CARB) on April 28, 2005 and became effective on May 17, 2006;
- The U.S. Environmental Protection Agency (EPA) lowered the 24-hour PM2.5 (particulate matter equal to or smaller than 2.5 micrometers) standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ in 2006. EPA designated the Bay Area as nonattainment of this PM2.5 standard on October 8, 2009;
- On June 2, 2010, the EPA established a new 1-hour SO_2 (sulfur dioxide) standard, effective August 23, 2010;

[8] Valero Improvement Project, Addendum to VIP EIR, June 2008, Available at: http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/%7B5A35F17D-5E23-404C-8032-6597BE84B5F9%7D.PDF.

[9] Valero Responses to: Valero Crude by Rail Project Data Request Number 2, April 2, 2013.

- The EPA promulgated a new 1-hour NO_2 (nitrogen dioxide) standard of 0.1 ppm, effective January 22, 2010;
- The EPA issued the greenhouse gas tailoring rule in May 2010, which requires controls of GHG emissions not contemplated in the VIP FEIR or the 2008 Addendum;
- The CARB has identified lead and vinyl chloride as "toxic air contaminants" with no threshold level of exposure below which there are no adverse health effects determined;
- The EPA issued a final rule for a national lead standard, rolling 3-month average, on October 15, 2008. The Project would increase lead emissions. Fox IS/MND Comments, p. 1, 20;
- Various BAAQMD regulations, including Regulation 2-2 (adopted December 19, 2012); and
- BAAQMD is currently developing a regional refinery regulation that could require additional emission controls.

B. Light Sweet Crudes

Light sweet crudes such as Bakken could be imported by rail and could result in an increase in ROG and TAC emissions from storage tanks, pumps, compressors, valves, and connectors that were not considered in the IS/MND. Fox IS/MND Comments, pp. 11, 25-28. The CBR Project DEIR concedes that "[o]nce the Project is constructed and operational, Valero may well purchase large amounts of light sweet North American crudes. In fact, this is Valero's stated plan." DEIR, p. C.2-1. Elsewhere, the DEIR notes that "[o]nce the Project is complete, Valero plans to obtain North American crudes that are, on average, lighter and sweeter than Valero's current feedstocks. According to Valero, the North American crudes will be 'Alaskan North Slope (ANS) look-alikes or sweeter' (Valero, 2013)." DEIR, p. 3-24. The closest and most cost advantaged of light sweet North American crudes listed in Table 3-1 that could be blended to be an ANS look-alike is Bakken crude.

An ANS look-alike crude, for example, could be created by blending 55% Bakken and 45% Western Canadian Select at a cost potentially far less than the ANS market price. The resulting mix has the same API gravity and slightly higher sulfur than ANS, and virtually identical distillation yields.[10] Both of these crudes are listed as available North American crudes in the DEIR. DEIR, Table 3-1. See also DEIR, pp. K-16/17. Alternatively, some of the lighter crudes, such as Bakken, could be fed directly to refining units, such as the fluid catalytic cracking unit (FCCU), eliminating the need for blending. Thus, the DEIR must evaluate the

[10] John R. Auers and John Mayes, North American Production Boom Pushes Crude Blending, Oil & Gas Journal, May 6, 2013, Available at: http://www.ogj.com/articles/print/volume-111/issue-5/processing/north-american-production-boom-pushes.html.

impacts of importing by rail and processing both Bakken and tar sands crudes, which span the range of likely impacts.

1. Bakken Crudes Have Properties That Will Result in Significant Impacts Not Evaluated in the DEIR

The DEIR makes the same arguments as to weight and sulfur content as previously made with respect to heavy sour crudes. The DEIR asserts that refining 70,000 bbl/day of light sweet crude would not cause an increase in ROG emissions because: "(a) Valero must blend crude feedstocks to a narrow range of weight and sulfur content before processing them, and (b) therefore, the average weight and sulfur content of crudes delivered to the Refinery will remain the same. In other words, any deliveries of light North American crudes by rail would simply replace the delivery of other light crudes by ship." DEIR, p. C.2-1. This is wrong for two principal reasons.

First, this is wrong because most of the ROG and TACs are emitted before the crudes are blended, from the rail cars, unloading, pipeline fugitive components (valves, pumps, connectors), and crude storage tanks. According to the Project description, two unit trains, each potentially carrying Bakken crude oil, would be unloading within a 24-hour period. DEIR, p. 3-22. This would result in an increase in daily ROG and TAC emissions, regardless of blending downstream to meet ANS-lookalike quality.

Second, this is wrong because all light sweet crudes are not created equal. The average weight (API gravity) and amount of sulfur in light sweet crudes do not determine the amount of ROG and TACs that will be emitted from Refinery tanks, pumps, compressors, valves, and connectors. The DEIR is correct when it asserts that "there is no relationship between the weight of a particular crude oil and the amount of fugitive emissions released from equipment containing that crude oil." DEIR, p. C.2-1. See also Figure 1.

The amount of ROG and TAC emissions is determined by the "volatility" of the crude and the concentration of TACs within the crude, not by its weight or sulfur content. The volatility can vary widely for "light sweet crudes," independent of weight and sulfur content. Processing in the oil fields, in particular, significantly affects volatility of shipped crudes, as discussed below. Bakken crudes, which are likely to be imported by the CBR Project, have uniquely elevated volatility, which has led to many spectacular accidents, such as those that occurred at Lac-Mégantic[11]; Casselton, North Dakota[12]; Alabama[13]; and more recently, Lynchburg, Virginia.[14]

[11] NTSB, Safety Recommendation In reply refer to: R-14-4 through -6; January 21, 2014. Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

Volatility is measured in pounds per square inch (psi) and is typically reported as Reid Vapor Pressure (RVP).[15] Vapor pressure is an indirect measure of the evaporation rate of volatile compounds in the crude oil, with higher vapor pressures indicating greater losses from evaporation. The DEIR neglected to disclose the well-known relationship between the vapor pressure of a crude and the amount of emissions released from equipment containing the crude,[16] which is incorporated into the EPA TANK 4.0.9d model, universally used to estimate ROG and TAC emissions from tanks, including in the DEIR for this Project.

The CBR Project would facilitate the import of Bakken crudes, which have uniquely elevated vapor pressures compared to the light sweet crudes they would replace. As discussed elsewhere in these comments, most of the imported crude that would be replaced is Alaska North Slope (ANS) crude (API gravity = 31.6^{o}, S = 0.96%) and similar or heavier foreign imports. The ANS crude has a Reid Vapor Pressure (RVP) of 6.3 psi.[17] Most foreign imports have an even lower RVP. In comparison, Bakken crudes (API gravity = 38-40^{o}, S = 0.2%), the most likely replacement, have a RVP of up to 15.5 psi.[18] Thus, replacing ANS and foreign imports with Bakken would increase ROG and TAC emissions from tanks and fugitive sources by up to a factor of 2.5. The TAC emissions would increase even more as the concentration of TACs in the Table 3-1 crudes are much higher than in the current crude slate.

The volatility and TAC speciation information required to evaluate this crude switch, from ANS, to an ANS-look alike based on a Bakken blend, is completely absent from the DEIR. Vapor pressure and crude TAC speciation information are not confidential and are routinely

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[12] NTSB, Preliminary Report; DCA14MR004, 2014. Available at: https://www.ntsb.gov/doclib/reports/2014/Casselton_ND_Preliminary.pdf.

[13] Karlamangla, Soumya, "Train in Alabama oil spill was carrying 2.7 million gallons of crude." Los Angeles Times, http://articles.latimes.com/2013/nov/09/nation/la-na-nn-train-crash-alabama-oil-20131109, November 9, 2013.

[14] Los Angeles Times, May 1 2014, http://www.latimes.com/nation/nationnow/la-na-nn-ntsb-investigation-fiery-crude-oil-train-derailment-virginia-20140501-story.html.

[15] Measured by American Society for Testing and Materials Method ASTM D323-08, Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method) is used to determine the vapor pressure at 100 F with initial boiling point above 32 F.

[16] See AP-42, Section 7.1: Organic Liquid Storage Tanks.

[17] ExxonMobil Refining and Supply Company, ANS11U, Available at: http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx and http://www.exxonmobil.com/crudeoil/download/ans11u.pdf.

[18] Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014, Available at: http://www.unece.org/fileadmin/DAM/trans/doc/2014/dgac10c3/UN-SCETDG-45-INF26e.pdf; Dangerous Goods Transport Consulting, Inc., A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation, Submitted by American Fuel & Petrochemical Manufacturers, May 14, 2014, pp. 5, 19, Available for download from: https://www.afpm.org;

North Dakota Petroleum Council, Bakken Crude Quality Assurance Study, Available at: http://www.ndoil.org/image/cache/Summary_2.pdf;

included in public documents to support tank and fugitive emission calculations. Further, crude assay data is widely reported.[19] See, for example, the Tesoro Vancouver Application.[20]

The DEIR offers irrelevant information to support its theory, arguing that "the amount of fugitive emissions from a piece of equipment is a function of the mechanical integrity of the equipment and the pressure applied to its contents. The weight of the crude oil is not a factor." DEIR, p. C.2-2. While this is partially correct, in that the design of the equipment and the pressure exerted by the contained crude oil on this design are important factors that determine the amount of emissions during routine operations, it fails to acknowledge other key factors such as RVP and TAC concentrations in the crude discussed above. The DEIR must evaluate the foreseeable scenarios of both light sweet crude, including Bakken, and heavy sour crude, including tar sands.

The foreseeable switch from ANS and other current components of Valero's crude slate to a Bakken crude or a Bakken-tar sands mix, included in DEIR Table 3-1, is a feedstock change that should have been explicitly identified and evaluated in the DEIR. These new crudes are chemically and physically different from the current crude slate and the crude slate evaluated in the VIP EIR in ways that are not captured by exclusive consideration of crude slate sulfur content and API gravity. These differences will result in significant impacts not evaluated or disclosed in the CBR Project DEIR.

Bakken crudes have unique chemical and physical characteristics that distinguish them from currently refined crudes and which would result in significant environmental impacts not identified in the DEIR, including significant risk of upset, air quality, odor, and public health impacts. These unique characteristics include high volatility, flammability,[21] and elevated concentrations of TACs and ROG.

The amount of TACs and ROG released from storage tanks and fugitive components depends upon the vapor pressure of the crude oil. Bakken crude oils are the most volatile of the

[19] Jeff Thompson, Public Crude Assay Websites, February 24, 2011. http://www.coqa-inc.org/docs/default-source/meeting-presentations/20110224_Thompson_Jeff.pdf.

[20] Tesoro Savage, Application for Site Certification Agreement (Vancouver Application), vol. 1, August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf and vol. 2, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

[21] Flammable crude oils will ignite when they are mixed with air in certain concentration ranges. The lowest temperature at which they produce sufficient vapor to support combustion is called the "flash point".

crudes listed in DEIR Table 3-1. Crude oil data collected by Capline Pipeline, which tested crudes from 86 locations world-wide for vapor pressure, found the following:[22]

> "[l]ight, sweet oil from the Bakken Shale had a far higher vapor pressure – making it much more likely to throw off combustible gases – than crude from dozens of other locations… According to the data, oil from North Dakota and the Eagle Ford Shale in Texas had vapor-pressure readings of over 8 pounds per square inch, although Bakken readings reached as high as 9.7 PSI. U.S. refiner Tesoro Corp., a major transporter of Bakken crude to the West Coast, said it regularly has received oil from North Dakota with even more volatile pressure readings – up to 12 PSI. By comparison, Louisiana Light Sweet from the Gulf of Mexico, had vapor pressure of 3.33 PSI, according to the Capline data."

This data, summarized in Figure 1, shows that "light" crude oils vary substantially in vapor pressure and thus would have a wide range of environmental impacts when stored and transported. The more volatile the crude, the higher the ROG, TACs, and methane (a potent greenhouse gas) emissions, the higher the flammability, and the greater the potential consequences in the event of an accident. Thus, the DEIR's assertions that there will be no increase in ROG and TACs as lights will replace lights is simply inaccurate.

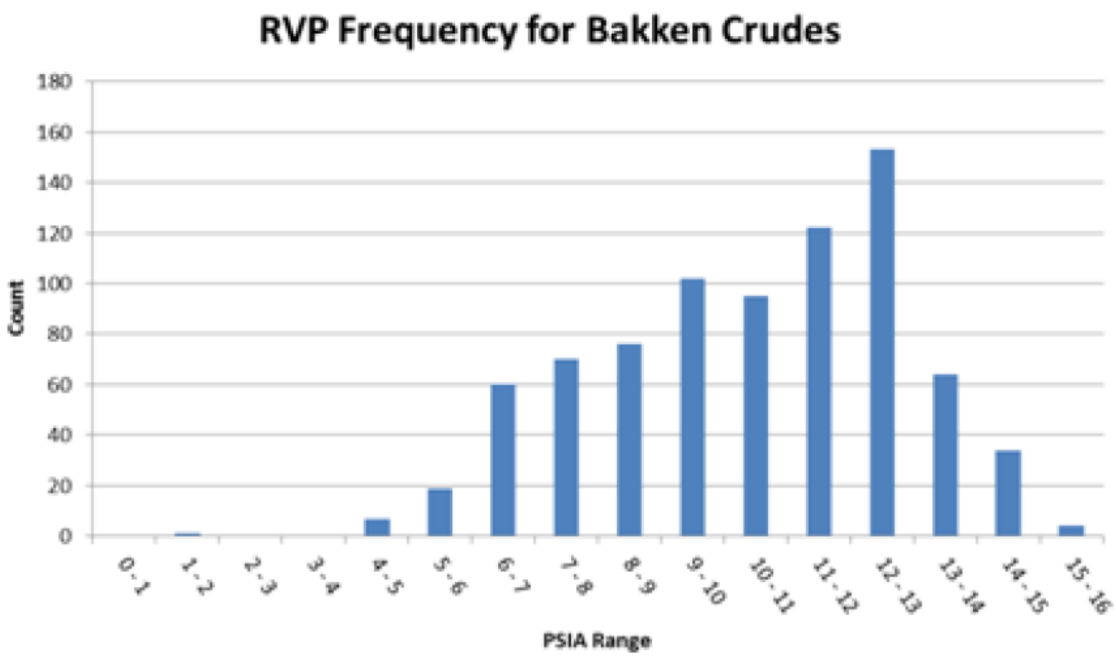
Figure 2: Volatility (psi) of Some Commonly Refined Crude Oils

Source: Wall Street Journal, February 23, 2014

[22] Russell Gold, Analysis of Crude From North Dakota Raises Further Questions About Rail Transportation, Wall Street Journal, February 23, 2014.

Other data, summarized by American Fuel & Petrochemical Manufacturers[23] indicate that the RVP of Bakken crude oil can be substantially higher than the value reported based on Capline Pipeline data. A study of Bakken crudes involved in the Lac-Mégantic accident by the Transportation Safety Board of Canada (TSBC)[24] concluded that the volatility and flammability of Bakken crudes were more similar to gasoline than to crude oil, distinguishing Bakken crudes from conventional crude oils.

Figure 3



Source: Dangerous Goods Transport Consulting, Inc., 2014

Bakken and other light crude oils taken straight from the well typically contain large amounts of natural gas liquids (NGLs), known as light ends or condensate.[25] These include C2 to C5 hydrocarbons: methane, propane, butane, ethane, and pentane. These are the components most likely to volatilize, burn, or explode in an accident. These light ends have the effect of increasing a crude's vapor pressure, lowering its flash point and lowering its initial boiling point, all of which result in increased environmental risks. These are called "live" crude oils. The high concentration of light ends makes them highly flammable, more likely to form fire balls and

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[23] Dangerous Goods Transport Consulting, Inc., 2014, North Dakota Petroleum Council.

[24] Transportation Safety Board of Canada, TSB Laboratory Report LP148/2013 (TSBC 2013), Available at: http://www.bst-tsb.gc.ca/eng/lab/rail/2013/lp1482013/LP1482013.asp.

[25] Dangerous Goods Transport Consulting, Inc., 2014, https://www.afpm.org/WorkArea/DownloadAsset.aspx?id=4229.

boiling liquid expanding vapor explosions (BLEVES) in accidents. The failure to recognize this resulted in a significant underestimate of ROG and TAC emissions and hazards in the CBR Project DEIR.

In most petroleum-producing regions, light ends are removed before they are shipped using a stabilizer—a tall, cylindrical tower that uses heat to separate the light ends, which are then condensed and sent to a fractionator for processing. Crude stabilizers and NGL pipelines to send the recovered NGLs to market are ubiquitous in oil fields that produce light crude oils as crude pipeline specifications set pressure limits that force stripping of the NGLs. However, in the Bakken fields, this infrastructure is rare and most Bakken crude that is shipped by rail is shipped live. This distinguishes it from other light crudes, which are shipped dry, e.g., Eagle Ford crudes in Texas, where oil field infrastructure exists to process it and most of it is shipped by pipeline, which requires that NGLs be stripped.[26]

Other crudes that Bakken would replace, such as ANS, are hard to ignite because they do not have as much combustible light ends. Most light crudes, including the imported foreign crudes currently processed, are stabilized. These stabilized crudes will not actively boil at ambient temperature and can be more safely shipped, stored, and refined. Thus, while "light" crude may replace other types of "light" crude, there are major differences in composition that affect environmental impacts. The CBR Project DEIR does not impose any condition(s) that require that NGLs be removed from received crudes to mitigate these impacts. Thus, analyses must assume that they will be present.

In addition, Bakken crudes, when blended with heavy crudes to meet crude slate requirements, have resulted in many refinery operating issues, which increase emissions. These include fouling of the cold preheat train; desalter upsets; and fouling of hot preheater exchangers and furnaces; as well as corrosion.[27] These operating problems increase emissions. These operating problems and attendant emission increases were not disclosed in the CBR Project DEIR.

2. Crude Slate Impacts Are Not Part of the Baseline

The DEIR next asserts that "[e]ven if VOC emissions were to increase based on Valero's purchase of light North American crudes, any such emissions increases would properly be considered part of the baseline because the baseline includes the full scope of operations allowed under existing permits that were issued based upon prior CEQA review." DEIR, p. C.2-1.

[26] 'Degassing' North Dakota Crude Oil Before Shipping Among Safety Ideas, Insurance Journal, May 14, 2014, Available at: http://www.insurancejournal.com/news/national/2014/05/14/329095.htm.

[27] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html.

Elsewhere, the DEIR asserts, "Finally, even if one assumed that Valero will purchase 70,000 barrels per day of light sweet North American crude, and the crudes delivered and processed became substantially lighter, any resulting increase in emissions would be within the baseline for operational air quality impact." This is supported by citing the same suite of CEQA cases relied on for the parallel argument with respect to heavy sour crudes discussed above. DEIR, p. C.2-2. The response to this argument around heavy sour crudes applies equally here and is incorporated by reference.

The baseline argument for light sweet crudes goes a step further than for heavy sour crudes, arguing that "Valero holds permits for all of the Refinery's process equipment… The City and the BAAQMD issued these permits based on the environmental impact report (EIR) for the Valero Improvement Project (VIP) prepared and certified by the City in 2003. The baseline includes the full scope of operations allowed under these permits. In particular, the baseline includes the permitted operation of the Refinery's eight crude oil storage tanks (storage tanks S-57 through S-62, S-1047, and S-1048). In connection with the VIP, the BAAQMD issued permits based on the City's EIR." DEIR, p. C.2-3.

This mischaracterizes the VIP EIR and the permits for the subject tanks. The VIP EIR evaluated only the two new storage tanks (VIP DEIR, p. 3-51) and the increase in ROG emissions from several other unidentified tanks up to a 5 ton/year increase in ROG relative to a 3-year baseline, based on a vapor pressure of 5 psi.[28] VIP DEIR, Table 4.2-9. The CBR Project would facilitate an additional increase in ROG and TAC emissions from these tanks over the same 3-year baseline, due to an increase in the vapor pressure of the stored crude oils and higher amounts of TACs in the rail-imported crudes. Thus, the VIP EIR did not evaluate the full scope of the ROG and TAC emissions that would occur as a result of the CBR Project.

In addition, the VIP EIR analyzed the TAC emissions from these tanks. These emissions were based on a speciation profile that assumes far less toxic air contaminants than would be present in the crudes listed in the CBR Project. DEIR Table 3-1. For example, the VIP EIR calculations assumed that benzene would be present in the crudes stored in new Tanks 1707 and 1708 at 0.009 weight percent (wt.%).[29] The benzene content of the suite of tar sands crudes listed in DEIR Table 3-1 are substantially higher than 0.009 wt.%, ranging from 0.02 wt.% to

[28] The BAAQMD Permit Handbook in Chapter 3.1 refers to U.S. EPA's AP-42 guidelines, Chapter 5.2, in which a default RVP for crude oil is listed as 5 psi, though it is noted that RVP of crude oils can range from less than 1 up to 10 psi. See: http://hank.baaqmd.gov/pmt/handbook/rev02/PH_00_05_03_01.pdf and http://www.epa.gov/ttnchie1/ap42/.

[29] The benzene concentration assumed in the storage tanks is calculated from post-VIP ROG emissions of 193 ton/yr (VIP DEIR, Table 4.2-9) and the post-VIP benzene emissions of 33.93 lb/yr (VIP DEIR, Table 4.7-6) as: 100x[33.93 lb/yr/(193 ton/yr)(2000 lb/ton)] = 0.009 wt%.

0.81 wt.%,[30] or over 2 to 90 times higher. Similarly, Material Safety Data Sheets (MSDSs) submitted by others seeking to import similar cost-advantaged North American crudes, including Bakken, indicate benzene concentrations up to 7 wt.%,[31] with Bakken crudes generally having the highest concentrations of benzene among all those evaluated. Benzene is a known human carcinogen. Human exposure to benzene has been associated with a range of acute and long-term adverse health effects and diseases, including cancer and adverse hematological, reproductive and development effects.[32]

The CBR Project DEIR incorrectly asserts that "even if the Project were to cause an increase in ROG emissions from storage tanks, any such increase would be considered part of the baseline conditions." DEIR, p. C.2-3. The CEQA baseline is not determined by permit conditions, but rather by actual conditions. The full scope of tank operations, i.e., storing crude oils that have much higher vapor pressures and concentrations of TACs than existed in the market place at the time of the 2002 VIP CEQA review, were never subject to CEQA review and must be evaluated in the instant case.

II. THE DEIR UNDERESTIMATED ROG EMISSIONS

The DEIR estimated that the Project would result in a net decrease in ROG emissions of 1.61 ton/yr, as summarized in Table 1. DEIR, Table 4.1-5.

Table 1: Annual and Daily Net Operational ROG Emissions

Source	ROG* (ton/yr)	ROG** (lb/day)
Unloading Rack & Pipeline Fugitive Components	1.88	10.30
Locomotives	1.70	9.32
Marine Vessels (Displaced Baseline)	-5.18	-28.38
Total Net Emissions	**-1.61**	**-8.77**

* Source: DEIR Table 4.1-5
** Calculated as (ton/year)(2000 lbs/ton)/(365 days/year)

[30] www.crudemonitor.ca. Concentrations reported in volume % (v/v) in this source were converted to weight % by dividing by the ratio of compound density in kg/m^3 at 25 C (benzene =876.5 kg/m^3) to crude oil density in kg/m^3, based on the most recent sample, as of June 27, 2014.

[31] TSBC 2013; Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets for Enbridge Bakken (n-hexane = 11%); sour heavy crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%); sweet heavy crude oil (toluene = 7%); light sweet crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%), August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

[32] CARB, Report to the Scientific Review Panel on Benzene, Prepared by the Staffs of The Air Resources Board and The Department of Health Services, November 27, 1984, Available at: http://www.arb.ca.gov/toxics/id/summary/benzene.pdf; Chronic Toxicity Summary: Benzene, Available at: http://www.oehha.org/air/chronic_rels/pdf/71432.pdf; World Health Organization, Exposure to Benzene: A Major Public Health Concern, Available at: http://www.who.int/ipcs/features/benzene.pdf.

The DEIR underestimated ROG emissions as it excluded many sources of ROG emissions from the Project, discussed below. The *increase* in ROG emissions is significant when these omissions are cured.

A. Decrease In Ship Emissions Are Not Real Or Enforceable

The ROG emissions in Table 1 assume marine vessel emissions would be reduced by 5.18 ton/yr, by eliminating 73 vessel trips (70,000 bbl/day x 365 day/350,000 bbl/vessel). DEIR, p. 4.1-16. The DEIR asserts that "[c]rude oil delivered to the Refinery by tank car would not displace crude oil delivered to the Refinery by pipeline." DEIR, p. ES-3, 1-1.

However, it is well known that San Joaquin Valley crude oil production is declining.[33] The nearby Shell Oil Refinery in Martinez, for example, recently increased crude storage capacity to substitute imported crude oil by marine vessel "for diminishing San Joaquin Valley crude by pipeline." DEIR, Table 5-1. ESA expressed concern that ship deliveries could increase in the future to replace diminishing supplies of crude oil available by pipeline. Valero 2013, Data Request No. 2, Item 1.[34] Further, the BAAQMD Statement of Basis for the VIP Project states: "Valero anticipates the possibility that crude may no longer be brought in by pipeline. This could result from a problem with the pipeline, or a change in the cost of crude that makes pipeline supply no longer economical."[35] Thus, it is entirely possible, especially in the absence of any enforceable conditions of approval, that the Project would not decrease marine deliveries to the extent claimed in the DEIR.

The DEIR must be modified to include clearly stated and enforceable provisions to assure that any increase in ROG and TAC emissions from importing crude by rail rather than by marine vessel or pipeline are fully offset by reductions in ship emissions and that the reductions are achieved in practice. These conditions should include requirements to test, record, and report to the City the RVP of all crude oil delivered by ship, rail, and pipeline and source testing of representative ship and locomotive emissions to assure the reductions are achieved.

B. Storage Tanks ROG and TAC Emissions Were Omitted

The DEIR did not adequately quantify emissions from the tanks that would store the crude oil delivered by rail. The emissions from floating-roof tanks include: tank breathing losses

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[33] California Energy Commission, Margaret Sheridan, California Crude Oil Production and Imports, April 2006, Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF.

[34] Valero Responses to: Valero Crude by Rail Project Data Request Number 2, April 2, 2013.

[35] http://www.baaqmd.gov/~/media/Files/Engineering/Title%20V%20Permits/B2626/B2626_2010-05_renewal_03.ashx?la=en.

(the sum of rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses estimated by the EPA model TANKS 4.0.9d) and roof landing losses.

1. Significant Tank Breathing Losses Were Omitted

Tank breathing losses are estimated using the EPA model: TANKS 4.0.9d. The CBR Project DEIR did not include any emissions from the tanks that would store the rail-imported crude.

The CBR Project DEIR describes the Project as replacing 70,000 bbl/day of crude oil delivered by ship with 70,000 bbl/day of crude oil delivered by train. The CBR Project DEIR fails to consider what happens to the crude oil after it is transferred from the rail cars through a new pipeline. DEIR, Sec. 3.2. It simply states that the contents of each tank car will be pumped "into storage tankage located in the Refinery's crude oil storage tank field." DEIR, p. 3-20. This crude oil will be stored in existing storage tanks. As the imported crude oil will have a higher vapor pressure than current crude oils stored in these tanks, ROG and TAC emissions from the tanks will increase. The VIP EIR did not evaluate these emission increases. The CBR Project DEIR also does not include these ROG and TAC emissions.

The Project described in the IS/MND included transferring crude oil from rail cars into existing external floating roof tank 1776. This required changing the service of this tank from jet fuel and other refinery products to crude oil. The ROG emissions were estimated with the EPA TANKS 4.0.9d model for a throughput of 70,000 bbl/day and a crude oil RVP of 9.4 psi. The resulting ROG emissions were 39.3 lb/day and 7.18 ton/yr. The net ROG emission increase, relative to December 2009 through November 2012 baseline, was 23.7 lb/day and 4.33 ton/yr. DEIR, Appx. E.3 (2/13 Application, Table 3-2). The supporting calculations for these emission increases (in Appendix B to the February 2013 Application, provided in DEIR, Appx. E.3, Attachments B-1 and B-2) were withheld from the DEIR as confidential business information (CBI).

The Project was modified in November 2013 to replace Tank 1776 with Tanks 1701 through 1708 (S-57 through S-62). These are existing external floating roof tanks that are currently permitted to store crude oil and have historically stored crude oil delivered by both ship and pipeline. DEIR, Appx. E.4 (11/13 Application, p. 6). Thus, the baseline emissions from these tanks include both San Joaquin Valley crudes and ANS and other ship-imported crudes. These tanks are not in the Title V permit for the Valero Refinery, but rather in the Title V Permit for NuStar Logistics, L.P., Facility B5574. The November 2013 Application incorrectly asserts that these tanks are neither altered nor modified sources and thus are not subject to Authority to Construct and New Source Review requirements for the CBR Project. DEIR, Appx. E.4 (11/13 Application, p. 7). The November 2013 Application at p. 7 (DEIR, Appx. E.4) asserts:

> "Changes in material stored. The tanks are currently permitted to store crude oil received by marine vessels and pipeline. With the implementation of this project, the tanks will continue to store crude oil. The crude oil will be received from rail cars, as well as from marine vessels and pipeline. Tanks 1701 through 1706 have historically stored crude oil delivered by ships and pipeline. Tanks 1707 and 1708 were recently constructed and were permitted under NSR to store crude oil. These tanks currently comply with all the requirements in Regulation 8, Rule 5, and associated permit conditions."

Similarly, the DEIR argues (DEIR, p. 4.1-17):

> "Nor would the Project cause any emissions increases from storage tanks. Currently, the Refinery stores crude oil delivered by ship and pipeline in eight existing storage tanks numbered 1701 through 1708. Crude oil delivered by rail would be stored in the same tanks. The tanks would not be modified, and would continue to be subject to the same throughput limit and other permit conditions."

Thus, the DEIR does not include any ROG or TAC emissions from these tanks. However, this assertion is invalid, as explained above. The basis of this argument is that "Valero must blend crude feedstocks to a narrow range of weight and sulfur content before they can be processed into marketable products. Because the crude oil blends cannot become significantly heavier or lighter, nor contain significantly more sulfur, there would be no increase in processing emissions." DEIR, p. 4.1.17. This is immaterial as to ROG and TAC emissions because they do not depend on weight and sulfur content of the crude, but rather on vapor pressure and TAC speciation of the crude. These are not related to the gravity or sulfur content of the crude oil.

The ROG and TAC emissions from the receiving storage tanks would increase if 70,000 bbl/day of ship-imported or pipeline-imported crude were replaced with 70,000 bbl/day of rail-imported crude. The DEIR is deficient for failing to include any estimate of these emission increases and for withholding all information required to estimate these emissions, information that is never classified as CBI in public documents—vapor pressures, tank characteristics, baseline emissions, etc.

An approximate estimate of the increase in daily ROG emissions can be made from the previously reported daily ROG emissions for Tank 1776. The IS/MND estimated daily ROG emissions of 39.3 lb/day for a 70,000 bbl/day throughput of crude with an RVP of 9.4 psi. The RVP of the baseline crude in the seven storage tanks that would be used is unknown. However, the DEIR indicates that it is either San Joaquin Valley crude (pipeline) or Alaska North Slope lookalikes.

First, assuming the baseline crude has an RVP equal to that for Alaska North Slope crude, or 6.3 psi,[36] the baseline ROG emissions for 70,000 bbl/day would be **26.3 lb/day**.[37] The increase in ROG emissions, from storing 70,000 bbl/day of Bakken crude in the same tank(s), assuming the reported upper-bound vapor pressure for Bakken crude (15.5 psi)[38] would be **64.8 lb/day**.[39] Thus, the net increase in ROG emissions from replacing 70,000 bbl/day of ship-imported ANS with 70,000 bbl/day of rail-imported Bakken is **38.5 lb/day** (64.8 - 26.3 = 38.5). The corresponding net increase in annual emissions would be **7.0 ton/year**[40] if all of the rail-imported crude were Bakken. This is a reasonably foreseeable scenario as crudes required to blend 100% Bakken to an ANS-lookalike crude could be imported by marine vessel

Second, assuming the baseline crude has an RVP equal to that of San Joaquin Valley crude or other similar heavy sour crudes, 0.04 psi,[41] the baseline ROG emissions for 70,000 bbl/day would be **0.2 lb/day**.[42] As detailed above, the increase in ROG emissions, from storing 70,000 bbl/day of Bakken crude in the same tank(s), assuming the reported upper-bound vapor pressure for Bakken crude (15.5 psi)[43] would be **64.8 lb/day**.[44] Thus, the net increase in ROG emissions from replacing 70,000 bbl/day of pipeline-imported San Joaquin Valley or other similar heavy sour crudes with 70,000 bbl/day of rail-imported Bakken is **64.6 lb/day** (64.8 - 0.2 = 64.6). The corresponding net increase in annual emissions would be **11.8 ton/year** if all of the rail-imported crude were Bakken. This is a reasonably foreseeable scenario as crudes required to blend 100% Bakken to an ANS-lookalike could be imported by marine vessel.

The resulting daily net increase in ROG emissions for a San Joaquin Valley or other similar heavy crude baseline, but otherwise assuming all of the CBR Project DEIR's emissions, is 56 lb/day, as shown in Table 2. This increase in ROG emissions is significant, as it exceeds

[36] ExxonMobil Refining and Supply Company, ANS11U, Available at: http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx and http://www.exxonmobil.com/crudeoil/download/ans11u.pdf.

[37] Baseline ROG emissions from storage of 70,000 bbl/day of ANS in one or more of existing tanks 1701 - 1708 = (39.3 lb/day) (6.3 psi/9.4 psi) = **26.3 lb/day**.

[38] Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014.

[39] Increase in POC emissions from storing 70,000 bbl/day of Bakken crude in one or more of existing tanks 1701-1708 = (39.3 lb/day)(15.5 psi/9.4 psi) = **64.8 lb/day.**

[40] Increase in annual emissions = (38.5 lb/day)(365 days/year)/(2000 lb/ton) = **7.02 ton/yr.**

[41] Emission Calculation Protocol for Oil Production Tanks, September 1, 2000.

[42] Baseline ROG emissions from storage of 70,000 bbl/day of ANS in one or more of existing tanks 1701 - 1708 = (39.3 lb/day) (0.04 psi/9.4 psi) = **0.17 lb/day**.

[43] Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014.

[44] Increase in ROG emissions from storing 70,000 bbl/day of Bakken crude in one or more of existing tanks 1701 - 1708 = (39.3 lb/day)(15.5 psi/9.4 psi) = **64.8 lb/day.**

the BAAQMD CEQA significance threshold[45] of 54 lb/day and triggers New Source Review thresholds that require Best Available Control Technology. This is a significant impact that was not disclosed in the DEIR. The total Project increase would be even greater than the emissions in Table 2, which do not include ROG increases from other omitted sources, discussed below.

Table 2: Revised Annual and Daily Net Operational ROG Emissions San Joaquin Valley Crude Baseline

Source	**ROG** (ton/year)	**ROG** (lb/day)
Unloading Rack & Pipeline Fugitive Components	1.88	10.30
Locomotives	1.70	9.32
Storage Tank (SJV Crude Baseline)	***11.79***	***64.60***
Marine Vessels (Displaced Baseline)	-5.18	-28.38
Total Net Emissions	**10.19**	**55.83**
BAAQMD CEQA Significance Threshold	10	54
Significant?	**YES**	**YES**

The increase in ROG emissions in Table 2 would be accompanied by an increase in TAC emissions, which are estimated by multiplying the ROG emission increase by the weight percent of each TAC in the ROG emissions (i.e., the TAC speciation profile). The contribution of TAC emissions from these tanks were not included in the DEIR's health risk assessment, which only evaluated diesel particulate matter and PM2.5.

Because the Project would result in significant ROG emissions, the lead agency is required to examine the impact of the increase in localized ROG emissions on ambient air quality and the local community and identify mitigation that is capable of reducing or eliminating these impacts to below a level of significance. To mitigate the Project's significant ROG emissions, the City should consider feasible mitigation measures such as the use of zero-leak fugitive components; use of geodesic domes on external floating roof tanks, which are commonly used on tanks that store RVP 11 crude oils; cable-suspended, full-contact floating roofs; and the use geodesic domes on the existing fixed roof tanks.[46]

[45] BAAQMD Proposed Air Quality CEQA Thresholds of Significance, May 3, 2010, Available at: http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Summary_Table_Proposed_BAAQMD_CEQA_Thresholds_May_3_2010.ashx?la=en.

[46] See, e.g., Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, September 6, 2013, Draft Negative Declaration (Carson Neg. Dec.), Available at: https://www.aqmd.gov/CEQA/documents/2013/nonaqmd/Draft_ND_Phillips_66_Crude_Storage.pdf and City of Richmond, Chevron Refinery Modernization Project DEIR (Chevron DEIR), Chapter 4.3, pp. 4.3-92, Available at: http://chevronmodernization.com/wp-content/uploads/2014/03/4.3_Air-Quality.pdf.

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

The increase in ROG emissions estimated above is based on an adjustment of a calculation in the IS/MND based on EPA's TANKS 4.0.9d model (TANKS). However, this model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses, inspection losses, or flashing losses. Thus, it underestimated tank emissions. Therefore, the above estimate of the increase in ROG emissions in Table 2 is an underestimate. These additional emissions should be estimated, added to other tank emissions, and mitigated when the DEIR is revised.

The Project involves seven existing external floating roof tanks configured to comply with BAAQMD Regulation 8-5. DEIR, p. 3-5. These tanks are pontoon-type tanks. DEIR, Appx. E.4 (2/13 Application, p. 1-8). Pontoon tank roofs are supported on legs. In floating roof tanks with leg-supported roofs, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operations. However, when the tank is emptied, the roof sits on the legs and is essentially uncontrolled.

The EPA has explained that the TANKS model does not include roof landings, and recommended that they be estimated with the equations in AP-42. In other words, the EPA TANKS model estimates evaporative emissions for normal operations only, *i.e.*, it assumes that the floating tank roof is always floating.[47] However, when a tank is emptied to the point that the roof no longer floats on the liquid but lands on deck legs, evaporative losses occur.

> After the floating roof is landed and the liquid level in the tank continues to drop, a vacuum is created which could cause the floating roof to collapse. To prevent damage and to equalize the pressure, a breather vent is actuated. Then, a vapor space is formed between the floating roof and the liquid. The breather vent remains open until the roof is again floated, so whenever the roof is landed, vapor can be lost through this vent.[48]

These losses are called "roof landing losses."

In addition, "degassing and cleaning losses" occur when tanks are drained and degassed for inspection and/or cleaning. These include both roof landing emissions, complete tank

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

[48] EPA, AP-42, Chapter 7.1 Organic Liquid Storage Tanks, November 2006, Available at: http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

degassing, and emissions from cleaning out accumulated sludge. These emissions are essentially uncontrolled tank emissions.[49]

The tank cleaning emissions could be substantially higher for Bakken crudes than for other types of crude. Bakken crudes leave waxy deposits in pipelines and tanks, which require more frequent cleaning,[50] and thus higher emissions, than the crudes they would replace. Environmental impacts from chemical dispersants used to control these waxy deposits in tanks and pipelines also should be evaluated.

The EPA recommends methods to estimate emissions from degassing and cleaning and roof landing losses.[51] The method for estimating emissions depends on the construction of the tank, *e.g.*, the flatness of the tank bottom and the position of the withdrawal line (the so-called liquid "heel"). Degassing, cleaning, and roof landing losses continue until the tank is refilled to a sufficient level to again float the tank roof. Total ROG emissions from floating roof tanks during a roof landing is the sum of standing idle losses and filling losses. They can be estimated using formulas contained in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7.1, Organic Liquid Storage Tanks, Section 7.1.3.2.2. These emissions are routinely included in emission inventories. They are required to be reported, for example, in Texas.[52] They are also included in the emission inventory for Tesoro's Vancouver Terminal, which imports similar crudes by rail, and stores them in tanks.[53]

To reduce emissions from tank breathing losses (Comment II.B.1), degassing, cleaning and roof landing losses, the City should require the Applicant to install geodesic domes on the tanks that would store rail-imported crudes, thus avoiding emissions from these and other tank sources.

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

[50] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, Available at: http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html.

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

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

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

Over 10,000 aluminum domes have been installed on petrochemical storage tanks in the United States.[54] The ExxonMobil Torrance Refinery: "completed the process of covering all floating roof tanks with geodesic domes to reduce volatile organic compound (VOCs) emissions from facility storage tanks in 2008. By installing domes on our storage tanks, we've reduced our VOC emissions from these tanks by 80 percent. These domes, installed on tanks that are used to store gasoline and other similar petroleum-derived materials, help reduce VOC emissions by blocking much of the wind that constantly flows across the tank roofs, thus decreasing evaporation from these tanks."[55]

A crude storage project, recently proposed at the Phillips 66 Los Angeles Carson Refinery, required external floating roof tanks with geodesic domes to store crude oil with an RVP of 11.[56] Carson Neg. Dec. Table 1-1. The ConocoPhillips Wilmington Refinery added a geodesic dome to an existing oil storage tank to satisfy BACT.[57] Similarly, Chevron proposes[58] to use domes on several existing tanks to mitigate VOC emission increases at its Richmond Refinery.[59] The U.S. Department of Justice CITGO Consent Decree required a geodesic dome on a gasoline storage tank at the Lamont, Texas refinery.[60] Further, numerous vendors have provided geodesic domes for refinery tanks.[61] The crudes that would be stored in the Project tanks have vapor pressures that are comparable to gasoline (TSBC 2013, Sec. 3.2.7), justifying the use of geodesic domes to control tank emissions.

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

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

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

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

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

[59] Chevron DEIR, Chapter 4.3.

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

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

3. Tank Flashing Emissions Were Omitted

Most Bakken crudes are transported raw, without stabilization, due to the lack of facilities in the oil fields, as discussed elsewhere in these Comments. Unstabilized or "live" crude oils have high concentrations of volatile materials entrained in the bulk crude oil. Tank flashing emissions occur when these crude oils, such as Bakken, are exposed to temperature increases or pressure drops. When this occurs, some of the compounds that are liquids at the initial pressure/temperature transform into gases and are released or "flashed" from the liquid. These emissions are in addition to working and breathing emissions from tanks and are not estimated by the EPA TANKS 4.0.9d model. These emissions can be calculated using standard procedures.[62] The DEIR did not mention or calculate these emissions, nor does it include permit conditions that would allow only stabilized crude oils to be received.

4. Water Draw Tank Emissions Were Omitted

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

C. Rail Car Unloading Emissions Were Omitted

The Project includes a rail car unloading rack capable of unloading two parallel rows of 25 crude oil rail cars simultaneously. DEIR, p. ES-3. The DEIR does not disclose any emissions from the unloading process, while EIRs for other similar facilities such as the proposed Phillips 66 CBR Project in Santa Maria, report unloading emissions.[63]

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

[63] Marine Research Specialists (MRS), Phillips 66 Company Rail Spur Extension Project Public Draft Environmental Impact Report and Vertical Coastal Access Assessment, November 2013; p. 2-14, Available at: http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/Draft+EIR-Phillips+66+Rail+Spur+Extension+Project+(November+2013)/Full+EIR+-+Large+File/p66.pdf.

At Valero, each side of the rack would have 25 unloading stations, which would "bottom-unload" closed-dome tank cars using 4-inch-diameter hoses, with dry disconnect couplings that would connect to a common header between the two sides of the rack (a check valve, connected to the top of each tank car via 2-inch-diameter hose would open to allow ambient air to enter during unloading and immediately close when unloading is finished). DEIR, p. 3-2.

A check valve would be installed onto each vent valve on the top of each tank car. The vent valve on the top of each tank car would be opened and the accompanying check valve would only allow fresh air into each tank car, and would prevent release of hydrocarbon fugitive emissions to the atmosphere. At each end car and on approximately every 8 tank cars in the 25 tank car string, a hose would be connected from the tank car's vent connection to a separate "equalization header." The equalization header would ensure the vapor spaces above the stored liquid crude in the tank cars is equalized between the tank cars. Individual drain hoses would be manually connected to the bottom of each tank car by on-site workers. The contents of each tank car would be drained by gravity into a collection pipe (collection header) and then pumped directly into storage tanks. DEIR, p. 3-21.

A typical rail car unloading system is described differently in the Santa Maria Rail DEIR. Santa Maria DEIR, p. 2-14. In that DEIR, the rail car unloading system consists of an adapter unit that connects the rail car to couplings, hoses, valves and piping that connect to a positive displacement pump. Air and crude oil vapors are commonly mixed in with crude oil, from loading and evaporation during transit. These vapors can present an explosion risk for downstream equipment and are typically removed with air eliminators. As the vapors contain high concentrations of ROG and TACs, they are typically routed to carbon columns or an incinerator to control the emissions.

The Valero CBR Project DEIR does not mention these vapors, an air eliminator, or indicate how they will be controlled. The Valero CBR Project DEIR only notes that "the BAAQMD will consider locomotive emissions and tank car unloading emissions as may be caused by the Project." DEIR, p. 3-2. This is not adequate. If unloading emissions will occur, at an air eliminator or other release point, the DEIR should be modified to describe them and to quantify them. If they are not present, the DEIR should explain how the explosion hazard typically associated with unloading cargos such as Bakken crude will be addressed as it is not clear that the air equalization system would eliminate this hazard.

D. Sump Emissions Were Omitted

The unloading facility includes a liquid spill containment sump with the capacity to contain the contents of at least one tank car. DEIR, p. ES-2. Crude oil that spills into this sump would release vapors including ROG and TAC emissions. The DEIR did not include these emissions.

E. Rail Car Fugitive Emissions Were Omitted

ROG and TACs will be emitted from rail cars from their point of origin through unloading as rail cars are not vapor tight. The DEIR did not include these emissions.

The crude oil would be shipped in tank cars, such that the volume of loaded crude oil shipped is less than the capacity of the rail car to accommodate expansion during shipping. This volume reduction creates free space at the top of the tank car, which provides space for entrained gases to be released from the crude oil[64] and emitted to the atmosphere during transit and idling in rail yards.[65]

As rail cars are not vapor tight, these vapors in the head space above the oil are emitted to the atmosphere during rail transport and at the unloading terminal. Further, most Bakken crudes are shipped live as discussed earlier. These crudes will flash in the tank cars when exposed to temperature increases or pressure drops, causing valves to open, emitting ROG and TACs.

These losses are consistent with the well-known "crude shrinkage" issue associated with crude by rail. The crude delivered is significantly less than the crude loaded. The reported range in crude shrinkage is 0.5% to 3% of the loaded crude.[66] Some of this shrinkage is likely due to emissions from the rail car during transit. The emissions of ROG and TACs from rail cars has been confirmed by field measurements.[67] The DEIR did not include these ROG and TAC emissions in its emission calculations or the health risk assessment.

Tank cars have domes to allow space for the product to expand as temperatures rise. Each dome has a manhole through which the tank car can be loaded, unloaded, inspected, cleaned, and repaired. Dome covers may be hinged and bolted on or screwed on. Most domes

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[64] Anthony Andrews, Congressional Research Service, Crude Oil Properties Relevant to Rail Transport Safety: In Brief, February 18, 2014, pp. 8-9.

[65] A DOT 111 (or comparable) tank car generally has a capacity of 34,500 gallons or 263,000 lbs. gross weight on rail. Under some conditions, the maximum gross weight can be increased to 286,000 lbs. At an API gravity of 50^{o}, a tank car can hold its maximum volume of 31,800 gallons and not exceed the 286,000 lb gross weight on rail limit. As the API gravity drops, the amount of oil that can be carried must also drop. Thus, a tank car of Bakken crude, at its highest density of 39.7^{o} API, can only hold 30,488 gallons, a volume reduction of about 1,300 gallons. Further, as crude oil density (and thus API gravity) is temperature dependent, volume will increase as temperature increases. Thus, the shipper may have to reduce the shipped volume even further. This volume reduction creates a space above the crude oil where vapors accumulate.

[66] Alan Mazaud, Exergy Resources, Pennsylvania Rail Freight Seminar, May 23, 2013, p. 17. Available at: http://www.parailseminar.com/site/Portals/3/docs/Alan%20Mazaud%20Presentation%20-%20AM.pptx

[67] http://www.youtube.com/watch?v=35uC1gLctnw.

have vents and safety valves to let out vapors.[68] Thus, they are sources of ROG emissions that were omitted from the emission calculations. Further, when dome covers are left open, any residual vapors escape to atmosphere. Residual material clings to the bottom and sides of empty rail cars and emits ROG and TAC while the rail cars idle at the site, waiting for the entire unit train to be unloaded. Open covers are common in railyards as they are opened for inspections and repairs. The ROG and TAC emissions from these sources were omitted from the DEIR's emission inventory.

Further, each tank car has a bottom outlet which is used for loading and unloading that includes pumps, manifolds, and valves, all of which leak ROG and TACs. Finally, liquid leaks occur when unloading arms are disconnected, even for the so-called no leak arms proposed for the Project. These disconnect leaks evaporate, contributing to ROG and TAC emissions.

An estimate of these emissions can be based conservatively on the lower end of the range of crude shrinkage (0.5%) discussed above and the maximum freight weight per car of 106 tons from the TRN Spec Sheet-1. DEIR, Appx. E.6 (6/11/14 Memo to Morgan from Velzy, pdf 1208). Assuming 50 cars/train and two unit trains per day, a total of 53 ton/day[69] of ROG can be emitted as the trains traverse the 1500 miles between the shipping point and the Valero rail terminal. Of these 1500 miles, 263 miles are within California.[70] DEIR, Appx. E.5 (Air Quality & GHG Supplement, pdf 1198). Thus, 9.3 ton/day of ROG (18,600 lb/day) can be emitted within California from rail car leakage.[71] Of the 263 miles within California, 22 miles are within the boundary of the BAAQMD. *Ibid.* Thus, 0.8 ton/day (1,555 lb/day) of ROG emissions can be emitted within the BAAQMD.[72] These daily emissions greatly exceed the BAAQMD daily CEQA significance threshold for ROG of 54 lb/day, requiring mitigation.

Additional ROG would be emitted at the Valero railyard, while railcars wait for the entire train to be unloaded, and from the emptied railcars, enroute to the cleaning facility, from residual product that clings to the bottom and sides of the railcars.

These ROG emissions contain the same chemicals found in the crude oil, including benzene, toluene, xylene, hexane, and ethylbenzene. As discussed below, some crudes can contain up to 7% benzene by weight. See Table 3 below. Thus, greater than 1,301 lb/day of benzene could be emitted in California and greater than 109 lb/day of benzene within the

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[68] Chapter 11. Tank Car Operations, Available at: http://www.globalsecurity.org/military/library/policy/army/fm/10-67-1/CHAP11.HTML.

[69] ROG emissions from train transit = (106 ton/car)(50 car/train)(2 train/day)(0.005) = **53 ton/day.**

[70] Distance within California = (136+390)/2 = 263 mi.

[71] ROG emitted within California = (318 ton/day)(263/1500) = **9.3 ton/day.**

[72] ROG emitted within BAAQMD = (318 ton/day)(22/1500) = **0.8 ton/day.**

BAAQMD from rail car leakage. This rail car leakage is much greater than the amount of benzene (and other TACs) included in the HRA. For example, the HRA included only 0.06 lb/day of benzene[73] from fugitive components (DEIR, Appx. E.4, pdf 1160) or a tiny fraction of the 109 lb/day of benzene that could be emitted within the BAAQMD from the rail cars themselves.

These are huge emissions, greatly exceeding the ROG (and HRA) CEQA significance thresholds of the BAAQMD and other air district along the rail route. See DEIR, Tables 4.1-5 and 4.1-6. The City must require mitigation for these ROG and TAC emissions.

III. THE DEIR FAILS TO DISCLOSE AND UNDERESTIMATES TAC EMISSIONS USED IN HEALTH RISK ASSESSMENT

Health Risk Assessments (HRAs) typically contain tables that summarize the amount of each TAC and the corresponding cancer, chronic, and acute health risk due to each. The supporting TAC emission calculations are presented in an appendix. The modelling files are separately attached. The HRA in this DEIR does not include most of this information. (Modelling files are available on a CD, which must be requested.) The supporting emission calculations are incomplete and scattered throughout many appendices with no road map explaining how it all fits together, with many analyses superseded.

There is no evident basis for concluding the Project would not result in a significant health impacts as the results are simply stated without the supporting emission calculations, leaving the reader the chore of digging through thousands of pages of appendices to make guesses at the TAC emissions included in the HRA analysis.

My analysis of this material indicates that the HRA only included diesel particulate matter and PM2.5 emissions from locomotives and TAC emissions from fugitive sources, a comparatively minor source of TAC emissions. The TAC emissions from all other sources (storage tanks, idling rail cars) discussed in Comment II were excluded. The TAC emissions from fugitive sources were underestimated, as explained below.

The unloaded crude oil will be transported from the unloading rack to existing crude supply piping in a 4,000–foot-long pipeline. DEIR, p. 1-2. The connecting system includes 3 pumps, 521 valves, 940 flanges, 295 connectors, and 6 pressure relief valves (plus a 15% contingency for valves, flanges and connectors). DEIR, Appx. E.4-1 (11/13 Application, pdf 1179). Crude oil vapors will be emitted from all of these components. The DEIR estimated TAC emissions from these components by first estimating ROG emissions using CARB

[73] Benzene in fugitive emissions from Ex. E.4, Table 3-5: (2.57E-3 lb/hr)(24 hr/day)/(2000 lb/ton) = **3.1E-5 ton/day.**

emissions factors. The ROG emissions were then multiplied by the weight percent of each TAC in the crude.

The TAC emissions from fugitive components were estimated using the "default speciation profile" for crude oil from the EPA program, TANKS4.09.[74] DEIR, Appx. E.4-1 (11/13 Application, pdf 1179, footnote). A "speciation profile" for a petroleum product identifies each chemical in the liquid and its concentration, reported as volume or weight percent. The default speciation profile used in the DEIR is not representative of the crude oil(s) that could be imported at the rail terminal and is entirely hypothetical. DEIR, Table 3-1. The conclusion that the hypothetical speciation profile is appropriate to evaluate Project health impacts is unsupported.

My review of the HRA speciation profile indicates that it is not based on the maximum amount of each TAC found in the crude oils that could be stored in the tanks. Material Safety Data Sheets (MSDSs) submitted in other applications to import cost-advantaged North American crudes[75] indicate that much higher concentrations of TACs could be present in the crude oils unloaded at the Valero Rail Terminal.

The upper bound values from these MSDSs are summarized in Table 3 and compared with the speciation profile used in the DEIR. This table shows that the HRA significantly underestimated all of the organic TACs included in the HRA. Similar information for diesel particulate matter, the only other TAC included in the HRA, is not available in the documents I reviewed.

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[74] Crude oil component speciation data was obtained by using the TANKS409d model available at http://www.epa.gov/ttnchie1/software/tanks/ using the database interface to export the speciation profile for the TANKS default crude oil, *viz.*, "Data --> Speciation Profiles --> Export" menu selection and choosing crude oil. This spreadsheet confirms that the default benzene level for crude oils is 0.6 wt.%.

[75] Tesoro Application to SCAQMD for Tank 80079 Throughput Increase, October 3, 2013, PRN 556835 (10/3/13 Application), MSDS for Light Sweet Crude, pdf 12; Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets, August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

Table 3: Comparison of DEIR Draft EIR, Appx. E.4, Table 3-5, HRA Speciation Profile for Fugitive Emissions with Maxima Reported in MSDS(s)[76]

TAC	Weight Percent		
	HRA Speciation Profile[77]	**Maxima MSDS**	**Factor Difference**
Benzene	0.6	7	11.7
Ethyl Benzene	0.4	7	17.5
Hexane	0.4	11	27.5
Toluene	1	7	7.0
Xylenes	1.4	7	5.0

Table 3 shows that the risk assessment underestimated the amount of benzene, ethyl benzene, hexane, toluene and xylenes in emissions by factors of 5 (xylenes) to 28 (hexane). Actual TAC emissions, after adjusting for the speciation profile, would be much higher as the DEIR excluded most of the sources of ROG emissions that would contribute TACs. The increase in benzene alone is large enough to increase the cancer risk at the maximum exposed individual worker (MEIW) over the BAAQMD Regulation 2-5 significance threshold of 1 in one million. DEIR, Appx. E.4-1 (11/13 Application, pdf 1189).

The DEIR argues that the benzene content of two Canadian crudes are on average lower than the benzene content of Alaska North Slope crude (0.33%), the design crude for the refinery. DEIR, Appx. K, p. K-17. However, the benzene content of other crudes listed in DEIR Table 3-1 are on average much higher than ANS. Light crudes, like Bakken, have been reported to contain benzene concentrations of up to 7 weight %, or twenty-one times more than the design ANS crude.

In sum, the DEIR fails to properly analyze the health impacts of importing, storing, and refining the crude oil that the CBR Project will likely bring to Valero.

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[76] Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets for Enbridge Bakken (n-hexane = 11%); sour heavy crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%); sweet heavy crude oil (toluene = 7%); light sweet crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%), August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf. See also 3/7/13 Revised Application, pdf 96-115.

[77] DEIR, Appx. E.4, Table 3-5, pdf 1160.

Comments

on

Revised Draft Environmental Impact Report

for the

Phillips 66 Rail Spur Extension and Crude Unloading Project

Santa Maria, California

Prepared

for

Communities for a Better Environment
Sierra Club
ForestEthics
Center for Biological Diversity

November 24, 2014

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Table of Contents

I. INTRODUCTION

The Phillips 66 Santa Maria Refinery (SMR), located in San Louis Obispo County, is proposing to modify an existing rail spur to accommodate train delivery of cost-advantaged crude oils, to replace local supplies. The proposed tracks and unloading facilities would be designed to accommodate unit trains of up to five unit trains per week, consisting of 80 tank cars and associated locomotives and other supporting cars as well as periodic manifest trains of fewer cars not dedicated to SMR oil (Project). I was asked by Communities for a Better Environment (CBE), the Sierra Club, ForestEthics, and the Center for Biological Diversity to review the Revised Draft Environmental Impact Report (RDEIR or Santa Maria RDEIR)[1]and prepare comments on a limited number of issues. This RDEIR replaces a former Draft Environmental Impact Report on a similar Project (DEIR)[2] issued in November 2013 that I also commented on.

My evaluation, presented below, indicates the RDEIR fails to disclose the link between the Rail Spur Project and three other directly related projects: (1) the Propane Recovery Project at Phillips 66's Rodeo facility; (2) the Rodeo Refinery Marine Terminal Offload Limit Revision Project; and (3) the Throughput Increase Project at the Santa Maria Refinery. The impacts of these directly related projects should have been evaluated as a single project. Together, they result in many significant impacts that were not disclosed in the Rail Spur Project RDEIR.

The RDEIR fails to evaluate the impacts resulting from a significant switch in crude slate, from locally sourced heavy crudes to tar sands crudes. The entire Project, comprising the four piecemealed projects, would result in significant unmitigated air quality, global warming, water supply, biological, and corrosion-caused risk of upset and other impacts, either not disclosed, improperly analyzed, or not mitigated in the RDEIR.

Finally, the RDEIR's hazard analysis fails to include the portions of the route where train accidents are most likely to occur due to steep grades and poor condition of tracks and bridges – from the stateline to the rail yards in Roseville and Colton, fails to analyze a worst case spill, and fails to disclose the significant difficulty of cleaning up a tar sands spill to waterways. The railroad tracks in these omitted areas parallel the water supply for most of California. A derailment that spilled significant amounts of tar sands crudes in these waterways could shut down the water supply for most of the state, resulting in significant unmitigated impacts on agricultural and municipal water supplies and significant aquatic biological impacts.

My resume is included in Exhibit 1 to these comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution

[1] San Luis Obispo County, Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report and Vertical Coastal Access Project Assessment, October 2014, SCH # 2013071028; Available at: http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/Phillips+66+Company+Rail+Spur+Extension+Project+(Oct+2014)/Phillips+SMR+Rail+Project+Public+Draft+EIR.pdf.

[2] Marine Research Specialists (MRS), Phillips 66 Company Rail Spur Extension Project Public Draft Environmental Impact Report and Vertical Coastal Access Assessment, November 2013.

control; greenhouse gas emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; hazard investigations; risk of upset modeling; environmental permitting; nuisance investigations (odor, noise); environmental impact reports/statements, including California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documentation; risk assessments; and litigation support.

I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. 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 documents. This work includes Environmental Impact Reports (EIRs), Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries as well as various other permitting actions for tar sands and light shale crude refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas and liquefied natural gas (LNG) facilities in Texas, Louisiana, and New York. I was a consultant to a former owner of the subject refinery on CEQA and other environmental issues for over a decade and am thus very familiar with both the Rodeo Refinery and the Santa Maria Refinery and their joint operations.

My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598 and *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310*.

II. THE PROJECT IS PIECEMEALED

The Phillips 66 San Francisco Refinery (SFR) consists of two facilities linked by a 200-mile pipeline. Santa Maria RDEIR, Fig. 2-2. The Santa Maria Refinery (SMR) is located in Arroyo Grande, in San Luis Obispo County, while the Rodeo Refinery is located in Rodeo in the San Francisco Bay Area. The Santa Maria Refinery mainly processes heavy, high sulfur crude oil and sends semi-refined liquid products, *e.g.*, gas oil and pressure distillates[3], to the Rodeo Refinery for converting into finished products. See, *e.g.*, Propane Recovery RDEIR, p. 3-25.

[3] The permits to operate for the Santa Maria Refinery and various pump stations along the pipeline indicate that the materials sent from Santa Maria to Rodeo are gas oil and "pressure distillates." The "pressure distillates" are referred to as "naphtha" in the subject RDEIRs. However, there are different types of naphtha, depending upon the boiling range. Full range naphtha, which is presumably what "pressure distillate" is intended to capture, is the fraction of hydrocarbons boiling between 30 C and 200 C. It consists of a complex mixture of hydrocarbons generally having between 5 and 12 carbon atmos and comprises 15% to 30% of the crude oil by weight. Light naphtha is the fraction boiling between 30 C and 90 C and consists of molecules with 5 to 6 carbon atoms. See, *e.g.*, http://en.wikipedia.org/wiki/Naphtha.

Phillips 66 is planning to replace a significant portion of its baseline crude slate with cost-advantaged crudes delivered to its California refineries by ship and rail. There are currently four related projects at the San Francisco Refinery (comprising the Santa Maria and Rodeo Refineries) that have recently been permitted or that are currently in the process of being permitted that are inextricably linked and should have been evaluated as a single Project under CEQA. Two are located at the Rodeo end of the pipeline and two are located at the Santa Maria end of the pipeline. These four projects are:

1. Santa Maria Refinery Throughput Increase Project;[4]
2. Santa Maria Refinery Rail Spur Project (RDEIR);
3. Rodeo Refinery Propane Recovery Project;[5]
4. Rodeo Refinery Marine Terminal Offload Limit Revision Project.[6]

I previously commented on the relationship between the Santa Maria Refinery Throughput Project, the Santa Maria Refinery Rail Spur Project,[7] and the Rodeo Refinery Propane Recovery Project[8] in comments on previous CEQA documents. These comments are included here in Exhibits 2 and 3. I reassert these comments as they are still valid and have not been addressed in either the Santa Maria Refinery Rail Spur Project RDEIR or the Propane Recovery RDEIR.

However, the SMR Rail Spur Project and Rodeo Refinery Propane Recovery RDEIRs both raise a new issue that seeks to demonstrate that these two projects are not related. This new issue, an alleged vapor pressure constraint, has not been addressed in other comments on piecemealing. The SMR Rail Spur Project RDEIR, p. 2-31, asserts out of the blue, without mentioning the Rodeo Refinery Propane Recovery Project:

> "Prior to pipeline shipment to the Rodeo Refinery the naphtha and gas oils are stored in tanks located at the SMR. These storage tanks have vapor pressure limits are required by the San Luis Obispo County Air Pollution Control District (SLOAPCD) permit, which limits the vapor pressure to 11 pisa [sic]. Historically, and currently the SMR tanks operate at about 10 psia (pounds per square inch absolute). These pressure limits restrict the amount of propane/butane that can be contained in naphtha and gas oils that are shipped to the Rodeo Refinery. The majority of the

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[4] Marine Research Specialists, Phillips 66 Santa Maria Refinery Throughput Increase Project, Final Environmental Impact Report, October 2012 (SMF FEIR); Available at: http://slocleanair.org/phillips66feir.

[5] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project Recirculated Draft Environmental Impact Report, SCH # 2012072046, October 2014, Available at: http://www.cccounty.us/DocumentCenter/View/33804.

[6] ERM and BAAQMD, CEQA Initial Study, Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Application 22904, December 2012; Phillips 66, Application for Authority to Construct and Minor Modification to Major Facility Review Permit, Revision of Permit Condition 4336 Part 7, Phillips 66 San Francisco Refinery; Major Facility Review Permit, Phillips 66 – San Francisco Refinery, Facility #A0016, Condition 4336, pp. 497-498, August 1, 2014.

[7] Phyllis Fox, Comments on Environmental Impact Report for the Phillips 66 Rail Spur Extension Project, Santa Maria, California, Prepared for Sierra Club, San Francisco, January 27, 2014.

[8] Phyllis Fox, Comments on Environmental Impact Report for the Phillips 66 Propane Recovery Project, Prepared for Shute, Mihaly & Weinberger LLP on behalf of Rodeo Citizens Association, November 15, 2013.

> propane/butane that is contained in the crude oils process at the SMR ends up in the refinery fuel gas. Figure 2-10 provides a simplified flow diagram of the SMR."

The Rodeo Refinery Propane Recovery Project RDEIR, on the other hand, includes a brief discussion of the Santa Maria Refinery. This discussion first asserts that "[t]he proposed Project [Propane Recovery] is independent of and would have no effect on SMF [Santa Maria Facility] operations." Propane RDEIR, p. 3-25. It goes on to make an argument, again out of the blue, that is very similar to the one cited above from the Santa Maria Refinery Rail Spur Project RDEIR (Propane RDEIR, pp. 3-25/26):

> "The storage tanks located along the 200-mile pipeline between the two refineries have maximum vapor pressure limits imposed by the San Luis Obispo County and San Joaquin Valley Air Pollution Control Districts which constrain the amount of butane and propane that can be included in the semi-refined products. Increasing the amount of butane and propane in the semirefined products would increase the vapor pressure of the material. Historically and currently these storage tanks contain products which are at or near the maximum vapor pressure limits. Additional butane and/or propane would cause the products to exceed the vapor pressure limits of the storage tanks. Accordingly, no new butane and propane can be added to the semi-refined products sent from the Santa Maria Refinery to the Rodeo Refinery regardless of the types of crude oil that may be processed at the Santa Maria Refinery."

These arguments attempt to demonstrate that there can be no link between these two projects as vapor pressure permit limits on tanks that store the gas oil and pressure distillate sent from Santa Maria to Rodeo would prohibit any increase in propane and butane as they historically and currently operate near their limits. These claims are incorrect as the assertions are wrong. There either are no vapor pressure limits on the subject tanks, or the materials stored in them have vapor pressures far below their permitted limits.

A. Vapor Pressure Constraints Are Unsupported

The RDEIRs contains no support whatsoever for these vapor pressure claims. Thus, it fails as a CEQA document. Support should include identification of the permits, tanks, and permit conditions that restrict vapor pressure and certified vapor pressure monitoring data for each subject tank. None of this information is in the record.

Therefore, I researched the issue, obtained permits, and identified the tanks that store the subject gas oil and pressure distillate, and obtained vapor pressure monitoring data from the San Luis Obispo County Air Pollution Control District (SLOCAPCD). My research indicates that these claims are wrong.

1. Santa Maria Refinery Tanks

The Santa Maria Refinery produces two semi-refined products – gas oil and pressure distillate. These products are stored in on-site tanks and sent by pipeline to the Rodeo Refinery to convert them to finished products such as gasoline. Emissions from these tanks are regulated by the SLOCAPCD Permit to Operate for the Santa Maria Refinery (Refinery Permit).[9] The Refinery Permit indicates that gas oil is stored in Tanks 800 and 801 and pressure distillate is stored in Tanks 550 and 511. PTO Conditions II.B.1.a and d, p. 8. The vapor pressure of the materials stored in these tanks should not appreciably change during pipeline transport to Rodeo. As discussed below, the vapor pressures of both gas oil and pressure distillate stored in tanks at the Santa Maria Refinery sent to Rodeo are significantly less than claimed in the RDEIRs.

a. Pressure Distillate Tanks 800/801

Pressure distillate, the more volatile of the two semi-refined products, is stored in 52,000-barrel, welded-shell, dome-roof tanks that are controlled by a methane blanket and vapor recovery system (Process A-2). These tanks must comply with SLOCAPCD Rule 425[10]. Rule 425, Section D.5.b applies. This section exempts these tanks from vapor pressure limits as emissions are controlled with a vapor loss control device listed in Section E.3 (E.3 Vapor Recovery System). Thus, there are no vapor pressure limits on the tanks that store pressure distillate that is sent to Rodeo as the vapors are recovered, contrary to the assertion in the SMR Rail Spur Project RDEIR that there is a vapor pressure limit of 11 psia.

The SMR Rail Spur Project RDEIR further asserts that the "SMR tanks operate at about 10 psia", without identifying the tanks. SMR Rail Spur Project RDEIR, p. 2-31. As gas oil is much less volatile, this comment likely refers to pressure distillate. Regardless, even if the pressure distillate tanks were limited to a vapor pressure of 11 psia (which they are not as they are otherwise controlled), the vapor pressure of the pressure distillate that is stored in them is not "about 10 psia". Rather, annual emission inventory data obtained from the SLOCAPCD (Exhibit 4) indicate that the pressure distillate tanks have operated at 6.2 psia over the period 2009 to 2013. Thus, the claims in the SMR Rail Spur Project RDEIR, p. 2-31, are wrong as to the pressure distillate storage tanks at the Santa Maria Refinery. These tanks do not have vapor pressure limits as they are controlled. Further, they are operating far below the erroneously claimed limit of 11 psia.

b. Gas Oil Tanks 500/501

Gas oil is stored in 76,500 barrel welded-shell, external floating pontoon roof, single shoe seal tanks. Rule 425, Section D.4, limits the vapor pressure of these tanks to 0.5 psia. Vapor pressure data that I obtained from the SLOCAPCD (Exhibit 4) indicate that the gas oils stored in these tanks had true vapor pressures of 0.27 psia over the period 2009 to 2013, much less

[9] Permit to Operate No. 44-52, Phillips 66 Company - Santa Maria Refinery, November 6, 2013.

[10] SIP Rule 407.A.2, also cited in this condition, is superceded by Rule 425. Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (2).

than 0.5 psia. The SLOCAPCD permit engineer explained that when higher vapor pressure material is encountered, it is routed to the pressure distillate tanks.[11]

2. <u>The SMR-to-Rodeo Refinery Pipeline</u>

The semi-refined products stored in Tanks 500, 501, 800, and 801 are pumped into the 200-mile long pipeline and sent to Rodeo for refining into finished products. There are several pump stations along this pipeline, used to increase the pressure as needed to overcome pressure losses from friction during transport. Storage tanks are present at some of these pump stations.

These materials are generally sent directly to Rodeo, without being diverted to tanks along the pipeline, as suggested in the Propane Recovery Project RDEIR, pp. 3-25/26. Phillips Pipeline LLC modified operation of this pipeline several years ago to reduce off-loading of gas oil and pressure distillate at pump stations.[12] While it is possible that an upset or operational abnormality could require material to be temporarily offloaded at pump station tanks, this is not the normal operational mode. Further, as discussed elsewhere, the vapor pressure of the semi-refined products are far below the vapor pressure limits. The former Creston and Summit pump stations were not needed after the operational change and thus no longer have active permits.[13] Other pump stations along the pipeline are primarily used just to push the material along.[14]

Thus, gas oil and pressure distillate that enters the pipeline at Santa Maria arrive at Rodeo with the same vapor pressure. The operation is steady state with little variation in measured vapor pressures from year to year.[15] The vapor pressure data reported by SLOAPCD (Exhibit 4) indicates that these tanks operate far below their permit limits. Within the SLOCAPCD, only the Santa Margarita and Shandon pump stations have active SLOCAPCD permits for storage tanks.

a. <u>*SLOCAPCD Pump Stations*</u>

Santa Margarita Pump Station Tanks

The Santa Margarita Pump Station Permit to Operate[16] lists four tanks. Three of them (55422, 55408, 110404) have vapor pressure limits of 11 psia, consistent with pressure distillate. Two of these pressure distillate tanks (55422, 55408) are vented to a carbon absorption vapor control system when pressure distillate is stored. The fourth tank (175420) has a vapor pressure limit of 1.5 psia. Vapor pressure data that I obtained from the SLOCAPCD (Exhibit 4) indicates the following vapor pressure ranges for these four tanks over the period 2009 to 2013:

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[11] Personal communication, Dean Carlson, SLOCAPCD, to Phyllis Fox, November 20, 2014.

[12] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (5).

[13] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 20, 2014, Re: P66 Pump Stations.

[14] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (5).

[15] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (4).

[16] SLOAPCD, Permit to Operate Number 404-9, Phillips Pipeline LLC, Santa Margarita Pump Station, May 2, 2012, Condition 5.

- Tank 55408: 0.26 to 4.79 psia (limit: 11 psia)
- Tank 55422: 0.36 to 5.05 psia (limit: 11 psia)
- Tank 11040: 0.24 to 0.4 psia (limit: 11 psia)
- Tank 175420: 0.07 to 0.49 psia (limit: 1.5 psia)

All of these tanks are operating at vapor pressures far below their permit limits. Thus, the claim in the RDEIRs that they are operating close to their limits, precluding any increase in propane and butane, is incorrect.

Shandon Pump Station Tank

The Shandon Pump Station Permit to Operate lists a single 35,000 barrel pontoon floating roof tank, permitted to store organic liquids with a true vapor pressure not to exceed 1.5 psia.[17] The SLOCAPCD inventory data also indicate that gas oil has been stored in this tank. Over the period 2009 to 2013, the true vapor pressure ranged from 0.12 psia to 0.24 psia, substantially lower than the 1.5 psia vapor pressure limit. Thus, the claim in the RDEIRs that this tank is operating close to its vapor pressure limit, precluding any increase in propane and butane, is incorrect.

b. <u>SJVAPCD Pump Station Tanks</u>

There are five pump stations in the San Joaquin Valley Air Pollution Control District (SJVAPCD) along the subject pipeline that have active permits to operate and which include tanks that could store gas oils and pressure distillate, if offloaded during transit to the Rodeo Refinery: (1) McKittrick (S1521); (2) Sunset (S 1522): (3) Shale (S1523); (4) Midway (S1525); and (5) Junction (S 1518). While I was unable to obtain either permits to operate or vapor pressure data for these tanks due to inadequate review time, there is no reason to expect that the vapor pressure of the SMR gas oils and pressure distillates shipped out of the SLOCAPCD into the segment of the pipeline under the jurisdiction of the SJVAPCD (and beyond the Bay Area Air Quality Management District (BAAQMD)) would change during transit to Rodeo. Further, there would be little if any reason to transfer pipeline material into these tanks, once destined for Rodeo.

[17] SLOCAPCD, Permit to Operate Number 505-4, Phillips Pipeline LLC, Shandon Pump Station, May 2, 2012, Condition 5.

B. Refinery Fuel Gas

The SMR Rail Spur Project RDEIR asserts that the majority of the propane and butane would be partitioned into the refinery fuel gas. SMR Rail Spur Project RDEIR, p. 2-31. This depends on the design of the crude tower, *i.e.*, the temperature cut points, which was not disclosed in the RDEIR. Distillate cut points could be optimized to route more of the propane and butane into the naphtha. However, I agree that most of the butane likely would be partitioned into the refinery fuel gas, but a significant amount of the propane would be present in the pressure distillate. Butane is present in much lower amounts than propane in the tar sands crudes identified in the RDEIR.

Regardless, the amount partitioned to the fuel gas at Santa Maria would depend on the amount present in the imported crudes, which would depend largely on the type of diluent if tar sands are imported, or otherwise, the specific light crude, as some are highly enriched in propane and butane.

The SMR Rail Spur Project RDEIR fails as a CEQA informational document as none of the information required to address this point is disclosed. Further, the semi-refined products from refining rail-imported crudes at the Santa Maria Refinery will generate additional amounts of propane and butane when refined at Rodeo, compared to the SMR baseline crude slate. Thus, the fuel gas argument is without merit.

C. Source of Increased Amounts of Propane and Butane Feedstocks at Santa Maria Refinery

The Santa Maria Rail Spur Project and Propane Recovery Project RDEIRs attempt to rebut any connection between these two projects by hiding behind the vapor pressure argument. However, this argument is not persuasive, as demonstrated above. In fact, most all of the cost-advantaged crudes flooding into the market will allow the SMR to produce propane/butane-rich, semi-refined products and the Rodeo Refinery to recover more propane and butane from them than available in their baseline crude slates.

The amount of propane and butane (or its precursors) in the Santa Maria Refinery rail-imported crudes could be substantial, significantly more than in the SMR baseline crude slate, depending upon the specific crudes that are imported. Pressure distillate is the lighter of the two semi-refined products sent to Rodeo. It is mostly naphtha with some material in the kerosene and diesel boiling range. The raw naphtha, for example, can contain significant amount of pentane,[18] which would be recovered at Rodeo by the Propane Recovery Project. Naphtha, for example, is a feed to the proposed LPG[19] Recovery Unit at the Rodeo Refinery. Further, Santa Maria Refinery gas oil is a feed to various hydrocracking units at Rodeo that break it down into recoverable propane and butane feedstocks.

[18] See, for example, Tesoro Material Safety Data Sheet, Naphtha; Available at: http://www.collectioncare.org/MSDS/naphthamsds.pdf.

[19] LPG = Liquefied Petroleum Gas = propane + butane.

The SMR Rail Spur Project RDEIR states that rail-imported crude oils would be sourced from oilfields throughout North America based on market economics and other factors. SMR Rail Spur Project RDEIR, pp. 1-4 & 2-22. The RDEIR identifies two tar sands crudes (RDEIR, pp. 2-3, 4.12-27, Tables 2.6 & 4.3.13, 4.7.14) and admits it has received another for about one year. SMR Rail Spur Project RDEIR pp. ES-14, 4.13-27, 2-31, 2-33, 5-3. While it asserts Bakken crudes will not be imported, the RDEIR does not contain any conditions that restrict the types of crudes that will be imported. Thus, the Santa Maria RDEIR should have evaluated the full range of potential cost-advantaged crudes that could be imported. The crudes that the RDEIR specifically identifies, plus other cost-advantaged crudes available in the market, would increase the amount of propane and butane that could be recovered at the Rodeo Refinery, compared to the SMR baseline. These various crudes are discussed below.

1. DilBit Tar Sands Crudes

The SMR Rail Spur Project RDEIR identifies Access Western Blend[20] and Peace River Heavy[21] as potential crudes that could be delivered via rail and processed at the Santa Maria Refinery. SMR Rail Spur Project RDEIR, pp. 2-3, 4.12-27, Tables 2.6 & 4.3.13, 4.7.14. The RDEIR also admits that SMR has received Canadian tar sands crude oil for about one year (post-baseline), specifically Kearl Lake, which made up 2% to 7% of the processed crude slate. SMR Rail Spur Project RDEIR pp. ES-14, 4.13-27, 2-31, 2-33, 5-3. The RDEIR also asserts that Bakken crudes will not be imported. However, the RDEIR does not contain any conditions that restrict the type of crudes that will be imported. Thus, the RDEIR should have evaluated the full range of potential cost-advantaged crude imported.

Most tar sands crudes are too heavy to flow in a pipeline and to be transported in the type of railcar proposed for the Project (*i.e.*, no steam coils or dedicated steaming facilities at Santa Maria), or unloaded and transferred to on-site storage tanks. Thus, they must be diluted or thinned with a lighter hydrocarbon stream to reduce viscosity. These diluted tar sands crudes are called "DilBits," which is a shorthand expression for blends of **dil**uent and tar sands **bit**umen. All of the tar sands crudes mentioned in the RDEIR are DilBits. A DilBit typically contains 25% to 30%+ diluent. The diluent is typically natural gas condensate, pentanes, or naphtha.[22] Diluent presents two opportunities to increase the amount of propane and butane that could be recovered at Rodeo.

First, chemical composition data for the three tar sands crudes identified in the RDEIR indicates they are loaded with propanes and butanes. Peace River Heavy contains 0.83 vol% butanes and 7.05 vol% pentanes.[23] Access Western Blend contains 0.69 vol% butanes and

[20] http://www.crudemonitor.ca/crude.php?acr=AWB.

[21] http://www.crudemonitor.ca/crude.php?acr=PH.

[22] Gary R. Brierley, Visnja A. Gembicki, and Tim M. Cowan, Changing Refinery Configurations for Heavy and Synthetic Crude Processing, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

[23] http://www.crudemonitor.ca/crude.php?acr=PH.

8.67% propanes.[24] Kearl Lake contains 0.83 vol% butanes and 10.2 vol% propanes.[25] Thus, it is indisputable that the targeted tar sands crude would contribute to the butane and propane that would be recovered by the Propane Recovery Project at Rodeo.

The SMR Rail Spur Project RDEIR alleges these butanes and propanes would be partitioned into the refinery fuel gas at SMR and thus would not reach the Rodeo Refinery. Most of the butane, present in much smaller amounts, could be partitioned to the fuel gas, depending on the temperature cut points of the distillation tower. However, most of the propane would remain in the straight run naphtha produced in the crude tower. SMR Rail Spur Project RDEIR, Fig. 2-10. Thus, the amount of butane and propane remaining in the semi-refined products headed to Rodeo, principally the pressure distillate, would be higher than in the baseline in which only heavy sour crudes were processed. SMR Rail Spur Project RDEIR, pp. 2-31. Further, operation of the crude tower could be modified to incorporate more of the propane and butane into the naphtha fraction.

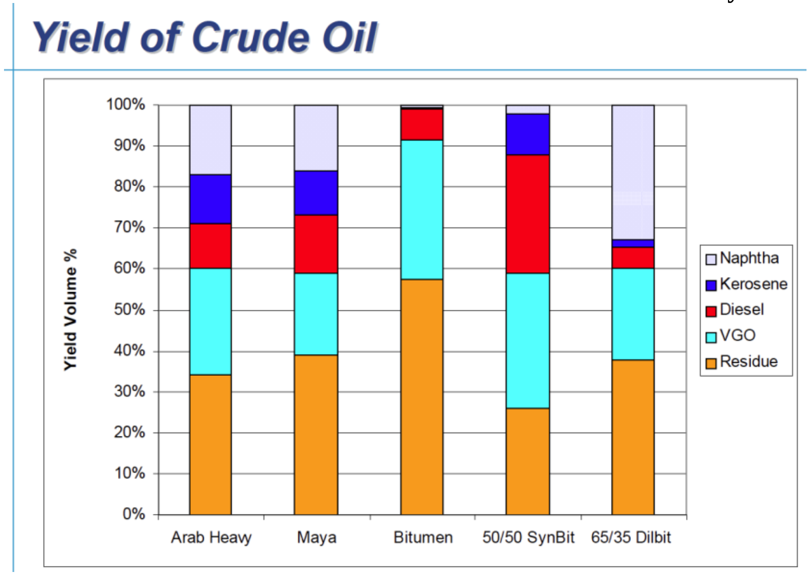
Second, DilBits, when refined, will yield much greater amounts of naphtha,[26] the lighter component of the pressure distillate sent to Rodeo and one of the feedstocks for propane recovery. Propane Recovery Project RDEIR, Fig. 3-6. The higher yield of naphtha from distilling DilBits, compared to heavy crudes, is illustrated in Figure 1. This bar chart compares the output of the distillation column (crude tower) for two commonly refined conventional heavy crudes (Arab Heavy and Maya, which are similar to the Santa Maria Refinery baseline crude slate) and three Canadian tar sands crudes (raw bitumen, SynBit, and DilBit). The last bar in Figure 1, 65/35 DilBit (65% bitumen, 35% diluent) is most similar to the crudes identified in the SMR Rail Spur Project RDEIR. Raw bitumen would be unlikely in large amounts without additional steam support at the proposed rail terminal. The SMR is not designed to refine SynBits so they also are unlikely imports.

[24] http://www.crudemonitor.ca/crude.php?acr=AWB.

[25] http://www.crudemonitor.ca/crude.php?acr=KDB.

[26] N. Yamaguchi, Tight Oil and Oil Sands in the U.S. Crude Slate: What Fuel Marketers Need to Know, Available at: http://fuelmarketernews.com/tight-oil-oil-sands-u-s-crude-slate-fuel-marketers-need-know/.

Figure 1
Distillation Yields of Conventional and Canadian DilBit and SynBit



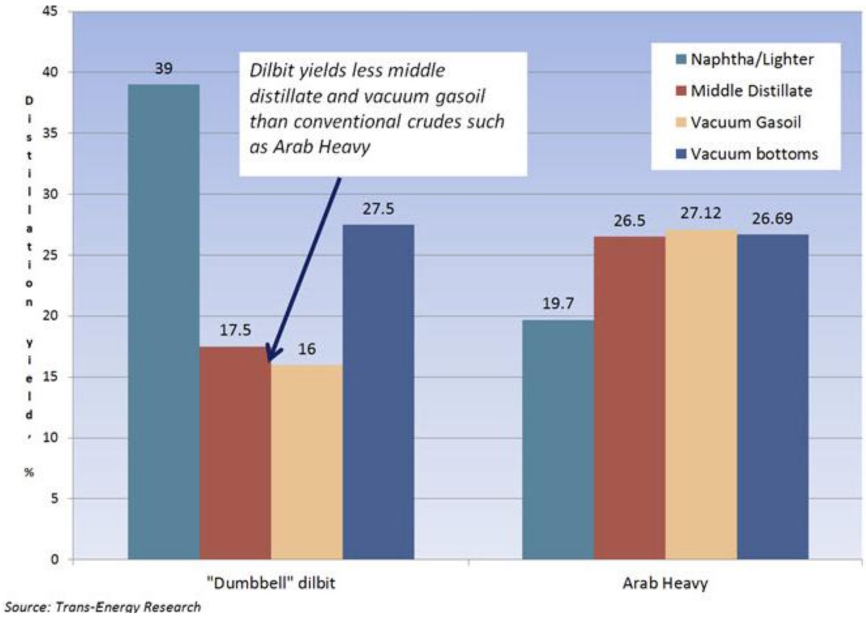
(From: Kevin Turini and others, Processing Heavy Crudes in Existing Refineries, Slides, 2011 AIChe Meeting, Chicago, IL

DilBits are sometimes referred to as "dumbbell" or "barbell" crudes as the majority of the diluent is C_5 to C_{12} and the majority of the bitumen is C_{30}+ boiling range material, with very little in between.[27] This means these crudes have a lot of material boiling at each end of the boiling point curve, but little in the middle. The 65/35 DilBit bar in Figure 1 indicates that these crudes generate about twice as much "naphtha" as the heavy crudes they would replace.

This is further confirmed by a different distillate yield bar chart from another source in Figure 2. This figure likewise confirms that switching from a heavy crude to a DilBit crude would roughly double the amount of naphtha distilled from the crude, from 19.7% to 39% and decrease gas oil from 27% to 16%. Additional amounts of both naphtha and gas oil would be produced by cracking the vacuum bottoms in the coker.

[27] Gary R. Brierley and others, Changing Refinery Configuration for Heavy and Synthetic Crude Processing, 2006; Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

Figure 2
Distillation Yields of a Conventional Heavy Crude (Arab Heavy) and DilBits



(from: Nancy Yamaguchi, Tight Oil and Oil Sands in the U.S. Crude Slate:
What Fuel Marketers Need to Know, Fuel Marketer News; Available at:
http://fuelmarketernews.com/tight-oil-oil-sands-u-s-crude-slate-fuel-marketers-need-know/

The DilBits yield very little middle distillate fuels, such as diesel, heating oil, kerosene, and jet fuel and more coke, than other heavy crudes. A typical DilBit, for example, will have 15% to 20% by weight light material, basically the added diluent, 10% to 15% middle distillate, and the balance, >75% is heavy residual material (vacuum gas oil and residue) exiting the distillation column. These characteristics, which distinguish DilBits from the current baseline crude slate, have two major implications.

First, refining of DilBits at SMR will generate more naphtha, the lighter semi-refined product, and less gas oil, thus changing the semi-refined product distribution. The increased amount of naphtha, when processed at the Rodeo Refinery, will generate more propane and butane. Naphtha, for example, is one of the feeds to the proposed LPG Recovery Unit. Propane Recovery Project RDEIR, Fig. 3-6. In other words, the increased amounts of naphtha produced from imported DilBit tar sands (or light tight crudes) would contain higher amount of propane and butane precursors, which would not be partitioned to refinery fuel gas at the Santa Maria Refinery as they would be present in the pressure distillate and refined at the Rodeo Refinery to recover butane and propane.

The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. The average baseline crude throughput for the Santa Maria Refinery (2010-2012) is 38,029 bbl/day. SMR Rail Spur Project RDEIR Table 2.7. Throughput data obtained from the SLOCAPCD indicates that this crude input generated 20,714 bbl/day of gas oil and 11,633 bbl/day of pressure distillate. Exhibit 5. Figures 1 and 2 indicate that DilBits could roughly double the amount of naphtha distilled from the crude oil. Assuming that all of the pressure distillate is naphtha, replacing 37,142 bbl/day of conventional heavy crudes with an equivalent amount of DilBit crude could increase naphtha yield from 11,633 bbl/day to 22,723 bbl/day (37,142/38,029 ×

11,633 × 2 = 22,723) in the baseline and significantly more once the SMR Throughput Project is operating at capacity. This significant increase in naphtha in the pressure distillate sent to Rodeo would allow the recovery of significant additional propane and butane at the Rodeo Refinery, relative to the baseline. This increase in naphtha in the pressure distillate would not exceed any tank vapor pressure limits as all of the tanks are operating far below their limit and the vapor pressure of the naphtha itself and the pressure distillate in which it is present are less than tank vapor pressure limits.

Second, the refining of DilBits at SMR will increase the amount of coke. This would increase emissions from coke dust and truck transport of coke, an impact not disclosed in the SMR Rail Spur Project RDEIR. This is further discussed in Comment III.

2. Other Tar Sand Crudes

The RDEIR also does not exclude the import of heavier tar sands crudes. In general, at refineries with cokers, such as Santa Maria Refinery, even decreases in API gravity (*i.e.*, heavier crude) can result in more propane and butane in the semi-refined products.[28]

3. Light Crudes

Finally, while the RDEIR asserts that Bakken crudes would not be imported (SMR Rail Spur Project RDEIR, pp. ES-5, 1-4, 2-1, 2-22), there are many other cost-advantaged light crudes that could be imported by rail. In general, the lighter the crude, the more butane and propane that can be recovered when it is refined.[29] These include new sources of cost-advantaged North American crudes, such as from the Permian (west Texas), Eagle Ford (south Texas), Granite Wash (Texas Panhandle), and Niobrara (Colorado) basins,[30] as well as Rocky Mountain Sweet (Casper, WY), and Mississippian Lime (Oklahoma).[31] Many of these crudes are already being refined by Phillips 66.[32] These crudes contain significant amounts of propane and butane and their precursors. The RDEIR does not exclude the rail import of any of these light, cost-advantaged crudes.

[28] NPC North American Resource Development Study, September 15, 2011, p. 18.

[29] See, *e.g.*, NPC North American Resource Development Study, Natural Gas Liquids (NGLs), September 15, 2011, p. 18; Available at: http://www.npc.org/prudent_development-topic_papers/1-13_ngl_paper.pdf.

[30] Dangerous Goods Transport Consulting, Inc., 2014, p. 23 (vol% C2 – C5 in Eagle Ford crude reported as 8.3%); Available at: composhttps://www.afpm.org/WorkArea/DownloadAsset.aspx?id=4229.

[31] Alan Mazaud, Exergy Resources, May 23, 2013, Pennsylvania Rail Freight Seminar, Slide: Growth of Domestic Production of Tight Oil.

[32] Phillips 66 Third Quarter Conference Call Slides, October 29, 2014; Available at: http://investor.phillips66.com/files/doc_presentations/2014/Earnings/PSX-Q3-News-Release-Slides-FINAL_v001_k94fx2.pdf.

4. Other Sources of Propane/Butane

The gas oils and naphthas sent to Rodeo would be further refined. This refining itself produces propane and butane. For example, the pressure distillate would be fed to hydrotreaters and hydrocrackers, which would produce propane- and butane-rich streams. The gas oils would be feed to cokers and hydrotreaters, which would also produce propane- and butane-rich streams. Thus, the increased amount of propane and butane that could be recovered when these semi-refined products generated from a lighter crude slate are further refined at Rodeo. Additional propane and butane could be generated at Rodeo itself by switching to a lighter crude slate.

D. Summary

In sum, the claims made in the RDEIRs in an attempt to decouple the Santa Maria Refinery Rail Spur Project and the Rodeo Refinery Propane Recovery Project based on vapor pressure limits have no merit. Some of the tanks have no vapor pressure limits at all, as vapors are recovered. All of the tanks operate far below their permitted vapor pressure limits. Further, the pipeline is operated to send semi-refined materials directly to Rodeo, without interim storage in pump station tanks along the pipeline. Even if semi-refined products had to be offloaded, their vapor pressures are far below permit limits. Thus, there is ample head room to increase the vapor pressure of semi-refined products shipped from Santa Maria to Rodeo.

III. EMISSIONS ARE UNDERESTIMATED

The SMR Rail Spur Project RDEIR estimated emissions from locomotives, fugitive emissions from railcars, pipeline components and crude oil storage tanks, a vapor recovery carbon canister, and vehicle traffic. SMR Rail Spur Project RDEIR, Sec. 4.3.4.2 & Appx. B. However, it omitted other sources of emissions, discussed below.

The SMR Rail Spur Project is proposing to replace the **majority** of the current crude slate (2010-2012: 38,100 bbl/day) with up to 100% tar sands crudes. The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. SMR Rail Spur Project RDEIR, p. 2-23. Thus, the Project would replace 97% of the baseline crude slate with up to 100% tar sands crude. The Throughput Increase Project will increase the crude permit level to 48,950 bbl/day. SMR Throughput Increase FEIR, p. 1-1. Thus, at full buildout, up to 76% of the crude slate will be different crudes than in the baseline, potentially 100% tar sands crudes. These new crudes have many chemical and physical properties that distinguish them from the baseline crude slate and that will result in impacts that were not evaluated in the SMR Rail Spur Project RDEIR. These were discussed for both tar sands and light crudes in my previous comments in Exhibits 2 and 3, which are incorporated here by reference.

A. Emission Changes Due To Changes in Fuel Gas Composition

The SMR Rail Spur Project RDEIR asserts that if significant amounts of propane and butane were present in the imported crudes, as discussed in Comment II, they would be partitioned into the Santa Maria refinery fuel gas. Assuming, *arguendo*, that this is correct, it would significantly increase the heat content of the refinery fuel gas. This would have several impacts. First, combustion temperatures would be higher in all heaters and boilers, as propane and butane burn with a hotter flame than natural gas and baseline refinery fuel gas, not enriched with propane and butane.[33] This would increase emissions nitrogen oxides (NOx) from all refinery fuel gas fired sources, compared to the baseline. Second, propane and butane have higher GHG global warming potentials than other components in refinery fuel gas.[34] Thus, greenhouse gas emissions from all heaters and boilers would increase. Finally, the significant increase in heat content may require modification or replacement of existing burner in heaters and boilers. None of these impacts were addressed in the SMR Rail Spur Project RDEIR.

B. Increased Combustion Emissions from Tar Sands Bitumen Not Evaluated

The SMR Rail Spur Project RDEIR indicates that tar sands crudes will be imported. The composition of tar sands crudes is chemically different from other heavy crudes currently processed at the SMR as they are tar sands bitumen mixed with diluent. They are unique for two major reasons: (1) presence of large quantities of volatile diluent full of reactive organic gases (ROG) and toxic chemicals as discussed above and (2) unique chemical composition of the bitumen, the heavy fraction. The previous comment discussed diluent, which will modify the composition of the both the semi-refined products sent to the Rodeo Refinery and the SMR refinery fuel gas. This comment discusses the unique composition of tar sands bitumens that require more intense processing and thus result in higher emissions.

Tar sands bitumens are composed of higher molecular weight chemicals and are deficient in hydrogen compared to conventional heavy crudes. This means more energy will be required and more emissions produced to convert them into the same slate of semi-refined and refined products. More energy will be required to add hydrogen and break the bonds of the larger molecules.

The SMR Rail Spur Project RDEIR concedes the hydrogen point. However, the SMR Rail Spur Project RDEIR argues that hydrogen addition occurs at the Rodeo Refinery, not at the Santa Maria Refinery, and thus did not include these emissions. SMR Rail Spur Project RDEIR, pp. 4.3-69/70. However, as explained in my comments in Exhibits 2 and 3 and comments by others on the SMR Rail Spur Project RDEIR (Pless 2014[35]; Karras 2014), the Rodeo Refinery Propane Recovery Project and the SMR Rail Spur Project should have been evaluated under CEQA as a single project as they depend on each other. Thus, the increase in emissions of criteria pollutants and greenhouse gases from most fired sources due to tar sands bitumen derived semi-refined products refined at the Rodeo Refinery should have been included in the emission inventory for the SMR Rail Spur Project.

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[33] Flame Temperatures of Some Common Gases; Available at; http://www.engineeringtoolbox.com/flame-temperatures-gases-d_422.html.

[34] See, *e.g.*, http://www.epa.gov/climateleadership/documents/emission-factors.pdf.

[35] Letter from Petra Pless to Laura Horton, Re: *Review of the Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report and Vertical Coastal Access Project Assessment*, November 21, 2014.

The Rodeo Refinery RDEIR is silent as to other crude quality factors that will increase emissions at Rodeo. Canadian tar sands bitumen is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular weight polymeric material.[36] Crudes derived from Canadian tar sands bitumen – DilBits, SCOs and SynBits – are heavier, *i.e.*, have larger, more complex molecules such as asphaltenes and resins,[37] some with molecular weights above 15,000.[38] They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[39] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker, which would occur at the Santa Maria Refinery. They require more intense processing in the coker to break them down into lighter products.

These differences are not reflected in any of the lumper parameters (API gravity, vacuum resid percentage, sulfur, TAN) presented in the SMR Rail Spur Project RDEIR. SMR Rail Spur Project Table 4.3-13 and p. 4.3-70. These differences mean that the coker at the Santa Maria Refinery will have to work harder to convert vacuum bottoms from distilling tar sand crude into gas oil, which will increase combustion emissions of NOx, sulfur oxides (SOx), carbon monoxide (CO), ROG, particulate matter with an aerodynamic diameter of 10 and 2.5 micrometers or less (PM10 and PM2.5), and greenhouse gases (GHGs). These increases in emissions were not included in the emission inventory.

C. Increased Metal Content from Tar Sands Were Not Evaluated

The Project could increase the import of heavy sour tar sands crude by up to 76% of the entire permitted capacity of the Santa Maria Refinery, once the SMR Throughput Project is fully operational. These crudes have higher metal content than the baseline crude slate.[40] This represents a significant increase in a type of crude that will increase emissions compared to the

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

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

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

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

[40] Straatiev and others, 2010, Table 1; Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils; http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF; F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010; Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf .

current Refinery slate. The impacts from this change were not evaluated in the SMR Rail Spur Project RDEIR.

The U.S. Geological Survey (USGS) reported that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil, such as those currently refined from local sources.[41] The SMR Rail Spur Project RDEIR reported vanadium and nickel concentration in a current "typical crude blend" compared to two potential tar sands crudes. SMR Rail Spur Project RDEIR, Table 4.3-13. This comparison shows that the vanadium concentration in Access Western Blend (190 ppmw) and Peak River Heavy (167 ppmw) are higher than the upper end of the range of major baseline crude sources. The SMR Rail Spur Project RDEIR is silent as to the significance of this reported increase in vanadium. The SMR Rail Spur Project RDEIR did not present any data for any other metal, known to be elevated in tar sands crudes.

The environmental damage caused by these metal pollutants includes bioaccumulation of toxic chemicals up the food chain and a direct health hazard from air emissions. These metals, for example, mostly end up in the coke. Thus, higher levels of metals will be present in the coke dust and coke pile runoff/seepage. The SMR Rail Spur Project DEIR indicated that "[m]etals that are present in coke have been detected in groundwater at concentrations above the California Department of Health maximum contamination levels (MCL) in the area around the coke pile runoff area..." SMR Rail Spur Project DEIR, p. 4.7-39/40. This statement has vanished from the SMR Rail Spur Project RDEIR. Thus, a switch to tar sands crude could contribute to this existing significant impact from the coke pile, which was not disclosed in the SMR Rail Spur Project RDEIR.

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

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

D. Sump Emissions Were Omitted

Unloading facilities generally include liquid spill containment sumps with the capacity to contain the contents of at least one tank car. Crude oil that spills into these sumps would release vapors including ROG, which are ozone precursors, and toxic air contaminant (TAC) emissions. The RDEIR is silent as to sumps and their emissions.

E. Rail Car Fugitive Emissions Were Omitted

ROG and TACs are emitted from rail cars from their point of origin through unloading as rail cars are not vapor tight. The SMR Rail Spur Project RDEIR did not include these emissions.

The crude oil would be shipped in tank cars, such that the volume of loaded crude oil shipped is less than the capacity of the rail car to accommodate expansion during shipping. This volume reduction creates free space at the top of the tank car, which provides space for entrained gases, such as those from diluent, to be released from the crude oil[42] and emitted to the atmosphere during transit and idling in rail yards.[43]

As rail cars are not vapor tight, these vapors in the head space above the oil are emitted to the atmosphere during rail transport and at the unloading terminal. The vapor in the headspace can flash during transport, when temperature increases or pressure drops, causing valves to open, emitting ROG and TACs.

These losses are consistent with the well-known "crude shrinkage" issue associated with crude by rail. The crude delivered is significantly less than the crude loaded. The reported range in crude shrinkage is 0.5% to 3% of the loaded crude.[44] Some of this shrinkage is likely due to emissions from the rail car during transit. The emissions of ROG and TACs from rail cars has been confirmed by field measurements.[45] The SMR Rail Spur Project RDEIR did not include these ROG and TAC emissions in its emission calculations or the health risk assessment.

Tank cars have domes to allow space for the product to expand as temperatures rise. Each dome has a manhole through which the tank car can be loaded, unloaded, inspected, cleaned, and repaired. Dome covers may be hinged and bolted on or screwed on. Most domes

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[42] Anthony Andrews, Congressional Research Service, Crude Oil Properties Relevant to Rail Transport Safety: In Brief, February 18, 2014, pp. 8-9.

[43] A DOT 111 (or comparable) tank car generally has a capacity of 34,500 gallons or 263,000 lbs. gross weight on rail. Under some conditions, the maximum gross weight can be increased to 286,000 lbs. At an API gravity of 50°, a tank car can hold its maximum volume of 31,800 gallons and not exceed the 286,000 lb gross weight on rail limit. As the API gravity drops, the amount of oil that can be carried must also drop. Thus, a tank car of Bakken crude, at its highest density of 39.7° API, can only hold 30,488 gallons, a volume reduction of about 1,300 gallons. Further, as crude oil density (and thus API gravity) is temperature dependent, volume will increase as temperature increases. Thus, the shipper may have to reduce the shipped volume even further. This volume reduction creates a space above the crude oil where vapors accumulate.

[44] Alan Mazaud, Exergy Resources, Pennsylvania Rail Freight Seminar, May 23, 2013, p. 17. Available at: http://www.parailseminar.com/site/Portals/3/docs/Alan%20Mazaud%20Presentation%20-%20AM.pptx

[45] http://www.youtube.com/watch?v=35uC1gLctnw.

have vents and safety valves to let out vapors.[46] Thus, they are sources of ROG emissions that were omitted from the emission calculations. Further, when dome covers are left open, any residual vapors escape to atmosphere. Residual material clings to the bottom and sides of empty rail cars and emits ROG and TACs while the rail cars idle at the site, waiting for the entire unit train to be unloaded. Open covers are common in rail yards as they are opened for inspections and repairs. The ROG and TAC emissions from these sources were not included in the SMR Rail Spur Project RDEIR's emission inventory.

Further, each tank car has a bottom outlet which is used for loading and unloading that includes pumps, manifolds, and valves, all of which leak ROG and TACs. Finally, liquid leaks occur when unloading arms are disconnected, even with state-of-the-art no leak arms. These disconnect leaks evaporate, contributing to ROG and TAC emissions.

An estimate of these emissions can be based conservatively on the lower end of the range of crude shrinkage (0.5%) discussed above and the maximum freight weight per car of 106 tons from the TRN Spec Sheet-1. Assuming 80 cars/train and five unit trains per week (SMR Rail Spur Project RDEIR, p. ES-5), a total of 30 ton/day[47] of ROG can be emitted as the trains travels from Canada to the Santa Maria Refinery rail terminal. The distance travelled outside of California was not reported, but is estimated to be about 1500 miles. The distance within California, on the longest route, is estimated as 300 miles one way. SMR Rail Spur Project RDEIR, p. B-9. Thus, about 17% of the 30 ton/day of ROG would be emitted in California or about 5 ton/day of ROG (10,000 lb/day) can be emitted within California from rail car leakage.[48] Of the 300 miles within California, 67 miles are within the boundary of the SLOCAPCD via the northern route. SMR Rail Spur Project RDEIR, p. B-9. Thus, 1.1 ton/day (2,200 lb/day) of ROG emissions can be emitted within the SLOAPCD from rail car leakage.[49] These daily emissions greatly exceed the SLOCAPCD daily ROG+NOx CEQA significance threshold of 25 lb/day (RDEIR, Table 4.3-17), requiring additional mitigation not identified in the RDEIR. These ROG emissions could be reduced by modifying the rail cars before they are shipped to minimize or eliminate leakage.

These ROG emissions contain the same chemicals found in the crude oil, including benzene, toluene, ethylbenzene, and xylene (collectively "BTEX") and hexane. Some crudes can contain up to 7% benzene by weight. Thus, greater than 154 lb/day of benzene could be emitted in California from rail car leakage. This rail car leakage is much greater than the amount of benzene (and other TACs) included in the SMR Rail Spur Project RDEIR's health risk assessment.

[46] Chapter 11. Tank Car Operations, Available at: http://www.globalsecurity.org/military/library/policy/army/fm/10-67-1/CHAP11.HTML.

[47] ROG emissions from train transit = (106 ton/car)(80 car/train)(5 train/week)(0.005)/(7 days/week) = **30 ton/day.**

[48] ROG emitted within California = (30 ton/day)(300/1500+300) = **5 ton/day.**

[49] ROG emitted within SLOCAPCD = (30 ton/day)(67/1500+300) = **1.1 ton/day.**

IV. THE SMR RAIL SPUR PROJECT RDEIR DID NOT EVALUATE THE INCREASE IN RISK OF ACCIDENTS AT THE SANTA MARIA REFINERY

The SMR Rail Spur Project RDEIR includes a brief discussion of the impact of changes in crude slate on hazards at the Refinery, designated as Impact #HM.3. SMR Rail Spur Project RDEIR pp. 4.7-63 and 4.7-65. This discussion touches on naphthenic acid corrosion, pointing to various inspection programs and ultimately dismissing corrosion-related accidents because "... the expected range of sulfur and TAN would be within the range of the crudes that are currently being processed at the SMR. Therefore, the change in crude slate would not be expected to change the sulfur or TAN levels compared to the crude sources that are currently being processed at the SMR." SMR Rail Spur Project RDEIR, Table 4.7-14 and p. 4.7-66. This is an inadequate discussion and the conclusions are wrong for several reasons.

First, corrosion failures in refineries are of great concern because of the high likelihood of "blowout" or catastrophic failure of components. This can happen because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it bursts, rather than leaking at a pit or local thin area that could be found during visual inspections. The process fluids carried in these lines are often above their auto-ignition temperature, resulting in large fires. They also usually carry toxic and hazardous materials, such as sulfur compounds (hydrogen sulfide, mercaptans, benzene) that can lead to toxic clouds, which can have significant adverse effects on surrounding communities.

Second, as background, it is important to recognize that the Rail Spur Project is proposing to replace the **majority** of the current crude slate (38,100 bbl/day) with up to 100% tar sands crudes. The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. SMR Rail Spur Project RDEIR, p. 2-23. Thus, the Project would replace 97% of the baseline crude slate with up to 100% tar sands crude. The SMR Throughput Increase Project will increase the crude permit level to 48,950 bbl/day. SMR Throughput Increase Project FEIR, p. 1-1. Thus, at full buildout, up to 76% of the crude slate will be different crudes than in the baseline, potentially 100% tar sands crudes.

Third, tar sands crudes have high Total Acid Numbers (TAN),[50] which indicates high organic acid content, typically naphthenic acids. Naphthenic acid attack occurs primarily in crude units and vacuum units, such as those at the SMR. SMR Rail Spur Project RDEIR, Fig. 2-10. They also form sludge and gum which can block pipelines and pumps. However, some acids are relatively inert. Thus, the TAN number does not always represent the true corrosive properties of a crude oil. Further, different acids will react at different temperatures, making it difficult to determine which processing units may be affected. As a rule-of-thumb, crude oils with a TAN number greater than 0.5 mg KOH/g are considered to be potentially corrosive and indicates a level of concern. A TAN number greater than 1.0 mg KOH/g is considered to be very high.[51] Canadian tar sands crudes are very high TAN crudes. The DilBits,

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

[51] Margaret Sheridan, California Crude Oil Production and Imports, Staff Paper, California Energy Commission, April 2006, p. 6; Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF.

for example, range from 0.98 to 2.42 mg KOH/g.[52] The Project is proposing to import crudes at the upper end of this range (SMR Rail Spur Project RDEIR, Table 4.7.14), far above the level of concern and far above the "typical crude blend" refined at SMR in the baseline. SMR Rail Spur Project RDEIR, Table 4.7-14. Thus, the RDEIR should have included a detailed analysis of the corrosion potential of the proposed crude slate and imposed mitigation.

Further, while the industry benchmark for TAN corrosion is 0.5, crudes with lower TANs can still cause significant corrosion problems, depending upon the specific acids. Sweet low TAN crudes, such as those currently flooding the market, and which could be imported by the Rail Spur Project, are also known to cause TAN corrosion.[53] The SMR Rail Spur Project RDEIR is silent on corrosion issues related to these crudes.

Fourth, each crude has its own unique characteristic chemistry and thus effects on corrosion. Refineries that process a consistent diet of a particulate crude or crude blend can base future predictions of corrosion potential on past experience. However, when a major switch in crude slate occurs, as proposed here, predicting future corrosion based on historic operating ranges or "typical crude blends", as in the SMR Rail Spur Project RDEIR, is not reliable. A new slate, even when major lumper parameters are in the historic range, minimizes the accuracy, or even the feasibility of predictions based on historic data.[54]

The rationale that sulfur levels and TAN of the crude slate would stay within the reported range and thus corrosion is not an issue, ignores the possibility of gradual creep in both sulfur and TAN within the usual range that could still be significant. The SMR Rail Spur Project RDEIR, for example, concedes that the new crude slate would increase sulfur by 0.8%. SMR Rail Spur Project RDEIR, p. 4.3-46. From a corrosion standpoint, this is a significant increase. The SMR Rail Spur Project RDEIR did not discuss the impact of a 0.8% increase in sulfur on corrosion-induced accidents at the SMR.

The high proportion of tar sands crudes in the future crude slate renders the ranges in SMR Rail Spur Project RDEIR Table 4.7-14 as irrelevant for concluding that the new crudes fall within the range of historic crudes. For example, if 100% Peace River Heavy[55] were refined, both its average sulfur and TAN level would exceed the sulfur (5.0%>4.2%) and TAN (2.5>1.0 mg KOH/g) concentrations in the baseline "typical crude blend." In fact, even the lower end of the reported range of sulfur and TAN in Peace River Heavy would exceed the "typical crude blend." The fact that the sulfur and TAN of Peace River Heavy falls within the reported ranges (S: 2.1 to 5.2%; TAN: 0.4-4.0 mg KOH/g) is simply irrelevant, as the SMR did not operate, on average, at the upper end of the range. Because the sulfur and TAN data for

[52] www.crudemonitor.ca.

[53] M.J. Nugent, J.D. Dobis, Experience with Naphthenic Acid Corrosion in Low TAN Crudes, Corrosion 98, Paper No. 577

[54] See discussion in API Recommended Practice 939-C, Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failure in Oil Refineries, First Edition, May 2009.

[55] Access Western Blend (TAN: 1.69-1.85 mg KOH/g; S: 3.94-3.96%); http://www.crudemonitor.ca/crude.php?acr=AWB and Peace River Heavy (TAN: 2.42 to 2.58 mg KOH/g; S: 4.94 to 5.08%); http://www.crudemonitor.ca/crude.php?acr=PH.

these tar sands crudes exceed the "typical crude blend" by significant amounts, corrosion impacts are significant and should have been disclosed, analyzed, and mitigated.

Fifth, the SMR Rail Spur Project RDEIR did not discuss or even mention sulfidation corrosion, which is a concern for refineries such as SMR, built in 1955 before current American Petroleum Institute (API) standards were developed to control corrosion and before piping manufacturers began producing carbon steel in compliance with current metallurgical codes. Rather, it notes in passing that "[h]igh sulfur levels can lead to sulfide related corrosion." SMR Rail Spur Project RDEIR, p. 4.7-65.

The early construction date suggests the metallurgy used throughout much of the SMR may not be adequate to handle the unique chemical composition of tar sands crudes without significant upgrades. There is no assurance that required metallurgical upgrades would occur if tar sands crudes dominate the crude slate, as they are very expensive and are not required by any regulatory framework. Experience with changes in crude slate at the Chevron Refinery in Richmond in the San Francisco Bay Area suggest required metallurgical upgrades are ignored, leading to catastrophic accidents.[56]

Sulfidation corrosion generally occurs above about 500 F for carbon steel pipe and above about 600 F for 5 Cr low-alloy steel. Some sulfide species are more corrosive than others, including mercaptans, hydrogen sulfide, and disulfides, all of which occur at elevated levels in tar sands crudes. Sulfidation corrosion manifests as uniform thinning and thus cannot be detected from visual inspections. Low silicon carbon steel can corrode 2 to 10 times faster than higher silicon carbon steel.[57]

How much low silicon carbon steel piping is present at SMR? What impact will an admitted 0.8% increase in sulfur have on this piping? What sulfur compounds are present in the 0.8% increase in sulfur? The SMR Rail Spur Project RDEIR did not disclose either the specific suite of sulfur compounds in the proposed imports or the metallurgy and operating conditions in the units potentially susceptible to sulfidation corrosion. Thus, it fails as an informational document under CEQA.

A catastrophic blowout due to sulfur creep recently occurred at the Chevron Richmond Refinery near the Rodeo Refinery. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit.[58] This change increased corrosion rates in the 4-sidecut line, which led to a

[56] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013; Available at: http://www.csb.gov/chevron-refinery-fire/.

[57] E.H. Niccolls, J.M. Stankiewicz, J.E. McLaughlin, and K. Yamamoto, High Temperature Sulfidation Corrosion in Refining, September 2008, 17th International Corrosion Congress, Corrosion Control in the Service of Society, Vol. 1 of 5, as cited in: Interim Investigation Report, Chevron Richmond Refinery Fire, August 6, 2012; Available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf.

[58] US Chemical Safety and Hazard Investigation Board, Chevron Richmond Refinery Pipe Rupture and Fire, August 6, 2012, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of

catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This accident sent 15,000 people from the surrounding area for medical treatment due to the release and resulting fire that created huge black clouds of pollution billowing over the surrounding community and across the San Francisco Bay.[59]

The SMR has a similar crude unit, identified as the "crude tower" in SMR Rail Spur Project RDEIR Figure 2-10. These types of accidents can be reasonably expected to result from incorporating tar sands crudes into the Santa Maria Refinery crude slate, even if the range of sulfur and TAN of the crudes remain the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentrations of sulfur in the heavy components of the crude coupled with high total acid numbers (TAN) and high solids, which aggravate corrosion. A crude slate change could result in corrosion from, for example, the particular suite of sulfur compounds or naphthenic acid content, that leads to significant accidental releases, even if the crude slate is within the current design slate basis, due to compositional differences. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from refining 76% to 97% tar sands crudes, leading to catastrophic releases.[60]

Elevated levels of TAN and sulfur can cause accidents that result in catastrophic releases of air pollution. Such releases were not considered in the SMR Rail Spur Project RDEIR. Rather, the SMR Rail Spur Project RDEIR relies on the SMR's existing Process Safety Management program, including the Management of Change (MOC) and Mechanical Integrity (MI) programs, to prevent corrosion. SMR Rail Spur Project RDEIR, pp. 4.7-65/66. However, these programs were also in place at the Chevron Richmond Refinery (and many other similarly afflicted refineries) at the time of the August 2012 accident discussed above. They did not prevent a catastrophic accident caused by sulfur (or TAN) creep. The recent Chevron Refinery Modernization Project FEIR incorporated many additional mitigation measures to improve these programs,[61] which should be required for the Santa Maria Refinery to mitigate the increase in sulfur and TAN in crudes imported by the Rail Spur Project.

Refinery emissions released in upsets and malfunctions can, in some cases, be greater than total operational emissions recorded in formal inventories. For example, a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were

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the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").

[59] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013, Available at; http://www.csb.gov/chevron-refinery-fire/.

[60] See, for example, K. Turini, J. Turner, A. Chu, and S. Vaidyanathan, Processing Heavy Crudes in Existing Refineries. In: Proceedings of the AIChe Spring Meeting, Chicago, IL, American Institute of Chemical Engineers; New York, NY, Available at: http://www.aiche-fpd.org/listing/112.pdf.

[61] See, for example, Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1 and 2, p. 4-40, Mitigation Measure 4.13-7h, Available at: http://chevronmodernization.com/project-documents/.

frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.[62]

Catastrophic releases of air pollution from these types of corrosion-caused accidents were not considered in the SMR Rail Spur Project RDEIR and are significant. Mitigation should be imposed, including at least the following:

- All mitigation measures required in the Chevron Refinery Modernization Project FEIR;
- 100% component inspection of all carbon steel piping systems susceptible to sulfidation corrosion; and
- Modification of work processes for review of damage mechanisms for processes covered by the Process Safety Management standard to conform with the American Petroleum Institute Recommended Practice 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry. The revised work processes shall require consideration of damage mechanism reviews as part of the Process Hazard Analysis process.[63]

V. RAIL ACCIDENTS WERE UNDERESTIMATED AND ARE SIGNIFICANT

The RDEIR evaluated "potential public safety and hazardous materials impacts" from train derailments and unloading accidents that could lead to fires and explosions. RDEIR, Sec. 4.7. Elsewhere, the RDEIR evaluates the impacts of derailments on water resources and biological resources. RDEIR, Secs. 4.4 & 4.13. These analyses are fundamentally flawed and incomplete, as explained below.

First, the RDEIR only analyzed impacts from the Roseville and Colton Rail Yards to the Project site. It did not analyzed impacts from the California border to these rail yards, arguing that trains could enter California at five different locations and thus the specific route was "speculative". RDEIR, pp. 4.7-1, 4.13-7. Routes are not "speculative" when they are known, as here. The trains can take any of them, depending on conditions. As they are known and any of these known routes can be taken, they are not speculative. The RDEIR should have evaluated all of them. Further, the trains can take multiple routes from the rail yards to the Santa Maria Rail Yard. The RDEIR, inconsistently, did not conclude that this rendered these routes speculative.

This is a serious omission as the segments from the state line to the rail yards pass through some of the state's most sensitive ecological areas and parallel the water supply for most of the state. These route segments also contain many high hazard areas for derailments.

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

[63] Terms and Conditions of Probation, People v. Chevron U.S.A. Inc., Superior Court of the State of California, County of Contra Costa, Case No. 1-162745-4.

Emergency response teams have generally good coverage in the urban areas, but none are located near the high hazard areas in rural Northern California that the RDEIR did not analyze.[64]

Second, the RDEIR did not analyze a worst case derailment. The RDEIR assumed a worst-case spill of 180,000 gallons, or about six tanker cars. RDEIR, p. 4.7-47. No support was provided for this choice. Rail accident records should have been reviewed to select a worst-case spill. The July 2013 Lac-Mégantic derailment spilled about 1.6 million gallons of Bakken crude oil, or about 53 railcars, covering an area of 77 acres.[65] The RDEIR should have based its analysis on a spill of at least 1.6 million gallons.

Third, the RDEIR did not analyze the impacts of a derailment on the state's water supply, which originates in the northern portion of the state along the rail segments eliminated from its analysis as "speculative". The rail routes from the state line to the rail yards parallel major rivers, such as the Sacramento, Yuba, Feather and American Rivers, which supply most of the water used throughout the state, distributed by a complex system of reservoirs and pipelines operated by Central Valley Project and the State Water Project. A significant spill of crude oil into any of these rivers would potentially shutdown the water supply for a significant portion of the state. This would have catastrophic and far reaching consequences that the RDEIR does not acknowledge, let alone analyze.

Fourth, the RDEIR notes that when spilled, a DilBit will sink (RDEIR, 4.13-27), but the RDEIR fails to disclose the resulting consequences on water supply and biological resources. The RDEIR is also silent on the difficulty of cleaning up the spill. An oil pipeline burst near Marshall, Michigan in July 2010, spilling a million gallons of DilBit in the Kalamazoo River. This spill decimated Talmadge Creek, a tributary to the Kalamazoo River, and about 40 miles of the river, prompting a more than $1 billion cleanup that, four years later, is still under way.[66] While most conventional crudes float on water, most of the DilBit, the bitumen component, sinks and clings to bottom sediments. This submerged oil is significantly harder to cleanup. The Kalamazoo spill, which occurred in 2010, is still not cleaned up.[67] The RDEIR failed to disclose

[64] Interagency Rail Safety Working Group, State of California, Oil by Rail Safety in California. Preliminary Findings and Recommendations, June 10, 2014.

[65] NTSB, Safety Recommendation In reply refer to: R-14-4 through -6; January 21, 2014. Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

[66] Keith Matheny, Environmental Disasters Lurk in Energy Pipelines, Detroit Free Press, October 12, 2014, Available at: http://www.freep.com/story/money/business/michigan/2014/10/12/energy-environmental-threats/17046063/.

[67] A Dilbit Primer: How It's Different from Conventional Oil, Inside Climate News. Available at: http://insideclimatenews.org/news/20120626/dilbit-primer-diluted-bitumen-conventional-oil-tar-sands-Alberta-Kalamazoo-Keystone-XL-Enbridge?page=show; Lindsey Smith, 3 Years and Nearly $1 Billion Later, Cleanup of Kalamazoo River Oil Spill Continues, Michigan Radio, July 25, 2013, Available at: http://michiganradio.org/post/3-years-and-nearly-1-billion-later-cleanup-kalamazoo-river-oil-spill-continues; NOAA Office of Response and Restoration, As Oil Sands Production Rises, What Should We Expect at Diluted Bitumen (Dilbit) Spills?, Available at: http://response.restoration.noaa.gov/about/media/oil-sands-production-rises-what-should-we-expect-diluted-bitumen-dilbit-spills.html; Witt O'Brien, A Study of Fate and Behavior of Diluted Bitumen Oils on Marine Waters, November 2013, Available at: http://www.transmountain.com/uploads/papers/1391734754-astudyoffateandbehaviourofdilutedbitumenoilsonmarinewater.pdf

the difficulty of cleaning up a large spill in one of California's headwater rivers that supply California's municipal, industrial, and agricultural water.

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November 24, 2014

San Luis Obispo County
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Murry Wilson
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VIA EMAIL
p66-railspur-comments@co.slo.ca.us
cc: mwilson@co.slo.ca.us

RE: Comments on the Revised Draft Environmental Impact Report for the Phillips 66 Company Rail Spur Extension and Crude Unloading Project

Dear Mr. Wilson,

Phillips 66 now admits that this is a tar sands crude by rail project. Nevertheless, the Revised Draft Environmental Impact Report ("RDEIR") for the Phillips 66 Rail Spur Extension and Crude Unloading Project ("Project") still fails to correct several deficiencies of the prior draft report, and fails as an informational document under the California Environmental Quality Act ("CEQA") for the additional reasons explained herein.

The Project Description remains inadequate in not fully addressing the scope of the company's total shift to a different quality of crude oil feedstock, and the RDEIR still obscures the inextricable link between the projects at the Santa Maria and Rodeo facilities. This, among other deficiencies, hides the true scope of the Project and precludes any adequate analysis of significant impacts.

The Santa Maria facility is the "front end" of the Phillips 66 San Francisco Refinery ("SFR"). The facility performs severe processing of oil streams that are then piped to the SFR's Rodeo facility to make into profitable engine fuels. This Project switches the SFR to refining tar sands oil. This rail expansion allows the company to get tar sands "dilbit" oils by rail, which the throughput increase allows it to convert into engine fuel feedstocks for the Rodeo facility. At

Rodeo, a liquefied petroleum gas expansion requires this change in oil processing, and allows some resultant byproducts, otherwise uneconomic to dispose of, to be recovered and sold.[1] The RDEIR's environmental review is, however, unnecessarily limited to primarily rail transport activities, with a wholly inadequate assessment of impacts and mitigation in light of its unpersuasive assertions of federal preemption. Overall, the RDEIR hides serious local pollution, climate pollution and chemical safety hazards from the public and its own workers. Accordingly, on behalf of Communities for a Better Environment, the Sierra Club, the Center for Biological Diversity, and Forest Ethics, we respectfully submit this comment, supported by several community based organizations and groups, cities, the California Nurses Association and thousands of California residents, seeking adequate environmental review of the Project, which is not reflected in the RDEIR. In addition, to date, approximately 22,000 residents have actively voiced concern against this Project.

Communities for a Better Environment ("CBE") is a California nonprofit environmental health and justice organization with offices in Oakland and Huntington Park. CBE has extensive organizational experience in protecting and enhancing the environment and public health by reducing pollution and minimizing hazards from refinery operations.

Sierra Club is a national nonprofit organization of over one million members and supporters dedicated to exploring, enjoying and protecting the wild places of the earth; practicing and promoting responsible use of the earth's ecosystems and resources; educating and enlisting humanity to protect and restore the quality of the natural and human environment; and using all lawful means to carry out these objectives. Sierra Club's Beyond Oil Campaign works to stem our nation's dependence on oil and to secure protections for communities and ecosystems from the significant toxic and global warming pollution emitted by oil development, including prevention of oil spills and other catastrophic events and pollution emissions that result from transporting extreme forms of oil by rail. Sierra Club has more than 143,000 members in the State of California who want to ensure that California's treasured landscape and coastline through which oil would be transported by rail are protected into the future.

The Center for Biological Diversity ("Center") is a non-profit environmental organization dedicated to the protection of native species and their habitats through science, policy, and environmental law. The Center has over 800,000 members and online activists throughout California and the United States, including members that live and/or visit the vicinity of the proposed project. These comments are submitted on behalf of our board, staff and members.

ForestEthics is a U.S. nonprofit organization that demands that corporations and government protect community health, the climate, and our wild places. ForestEthics fights to stop dangerous extreme oil trains and pipelines and has secured the protection of 65 million acres of wilderness by pushing major companies to shift hundreds of millions of dollars to responsible purchasing. ForestEthics has over 14,000 supporters in California.

As set forth below and in Attachments A-F, which include the expert reports of Phyllis Fox, Ph.D., PE ("Fox Revised Santa Maria Report," Attachment C), and Greg Karras ("Karras Revised Santa Maria Report," Attachment B), the RDEIR suffers from numerous deficiencies

[1] The Phllips 66 Rail Spur Extension and Crude Unloading, Throughput Increase, and Propane Recovery Projects.

that render it inadequate under the California Environmental Quality Act[2] ("CEQA") and the CEQA Guidelines[3] ("CEQA Guidelines"). We respectfully request that the County reject the RDEIR as an environmental review document, and defer approval of the Project until such time as the RDEIR is revised to comply with CEQA, which includes following the procedures detailed in section I addressing lead agency review of piecemealed projects.

An EIR is "the heart of CEQA."[4] "The purpose of an environmental impact report is to provide public agencies and the public in general with detailed information about the effect which a proposed project is likely to have on the environment; to list ways in which the significant effects of such a project might be minimized; and to indicate alternatives to such a project."[5] The EIR "is an environmental 'alarm bell' whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return. The EIR is also intended 'to demonstrate to an apprehensive citizenry that the agency has, in fact, analyzed and considered the ecological implications of its action.' Because the EIR must be certified or rejected by public officials, it is a document of accountability."[6] The RDEIR for the proposed Project still fails entirely to live up to this mandate, therefore, it violates CEQA, and violates several principles of Environmental Justice.

I. ENVIRONMENTAL REVIEW SHOULD PROCEED UNDER A PROGRAM EIR.

"A program EIR is an EIR which may be prepared on a series of actions that can be characterized as one larger project."[7] Emphasized throughout this comment, the Project is piece-mealed and cannot achieve its objective independently, without either the Throughput Increase or Rodeo Propane Recovery projects.

As the Project is part of "one larger project," it would be more appropriate to analyze it under a Program EIR. This has several advantages: providing a more exhaustive consideration of effect and alternatives than would be practical in an EIR, ensuring adequate consideration of cumulative impacts that "might be slighted in a case-by-case analysis," allowing for an earlier and more practical consideration of mitigation measures, and saving considerable agency resources.[8]

Where there could be more than one lead agency, as in this case, the lead agency which acts first on the project shall be the lead agency.[9] On June 8, 2010, the County of San Luis Obispo Planning and Building Department issued the Notice of Preparation for the Refinery Throughput Increase Project. On July 24, 2012, the Contra Costa County Department of Conservation and Development issued a Notice of Preparation and Scoping Session for an EIR for the Phillips 66 Propane Recovery Project. On July 8, 2013, the County of San Luis Obispo

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[2] Pub. Res. Code § § 21000 *et seq.*
[3] 14 Cal. Code Regs. § § 15000 *et seq.*
[4] *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("*Laurel Heights I*").
[5] Pub. Res. Code § 21061
[6] *Laurel Heights I*, 47 Cal. 3d at 392 (citations omitted).
[7] CEQA Guidelines § 15168.
[8] *Id.*
[9] CEQA Guidelines § 15051.

Planning and Building Department issued the Notice of Preparation for the Rail Spur Project. The County of San Luis Obispo Planning and Building Department acted first with the first component of this project, the Throughput Increase project, and is therefore the appropriate lead agency for a program EIR.

Consequently, pursuant to the CEQA Guidelines, it would benefit the County to withdraw this RDEIR and move forward under a programmatic EIR approach. This would also yield a more accurate assessment of the significant and cumulative impacts and mitigation measures for all communities affected by the SFR's switch to refining tar sands.

II. THE EIR'S PROJECT DESCRIPTION IS INADEQUATE.

A. The Project Description Fails to Disclose an Industry Shift to a Different Quality Crude Feedstock

In order for an environmental document to adequately evaluate the environmental ramifications of a project, it must first provide a comprehensive description of the project itself. "An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient EIR."[10] As a result, courts have found that, even if an EIR is adequate in all other respects, the use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency did not proceed in a manner required by law.[11]

Furthermore, "[a]n accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity."[12] Thus, an inaccurate or incomplete project description renders the analysis of significant environmental impacts inherently unreliable. While extensive detail is not necessary, the law mandates that EIRs should describe proposed projects with sufficient detail and accuracy to permit informed decision-making.[13] The RDEIR's Project Description fails to meet this standard by minimizing the degree and scope of the switch in crude oil feedstock supply.

The RDEIR's Project Description is misleading. From the outset, the RDEIR limits its Project and Project-related impacts analyses solely on the Project's rail operations. However, this is not simply a transport infrastructure project. The RDEIR instead states that the primary objective of the project is to "allow the refinery to obtain…crude oil…from…North American sources that are served by rail…(by) install(ing) the necessary infrastructure."[14] The RDEIR's avoidance of this fact diminishes the true intent and scope of the Project, which is, in reality a project to receive tar sands. Indeed, this Project expressly enables and locks in refining of tar sands at the SFR: "tar sands oils would likely dominate the new crude source."[15]

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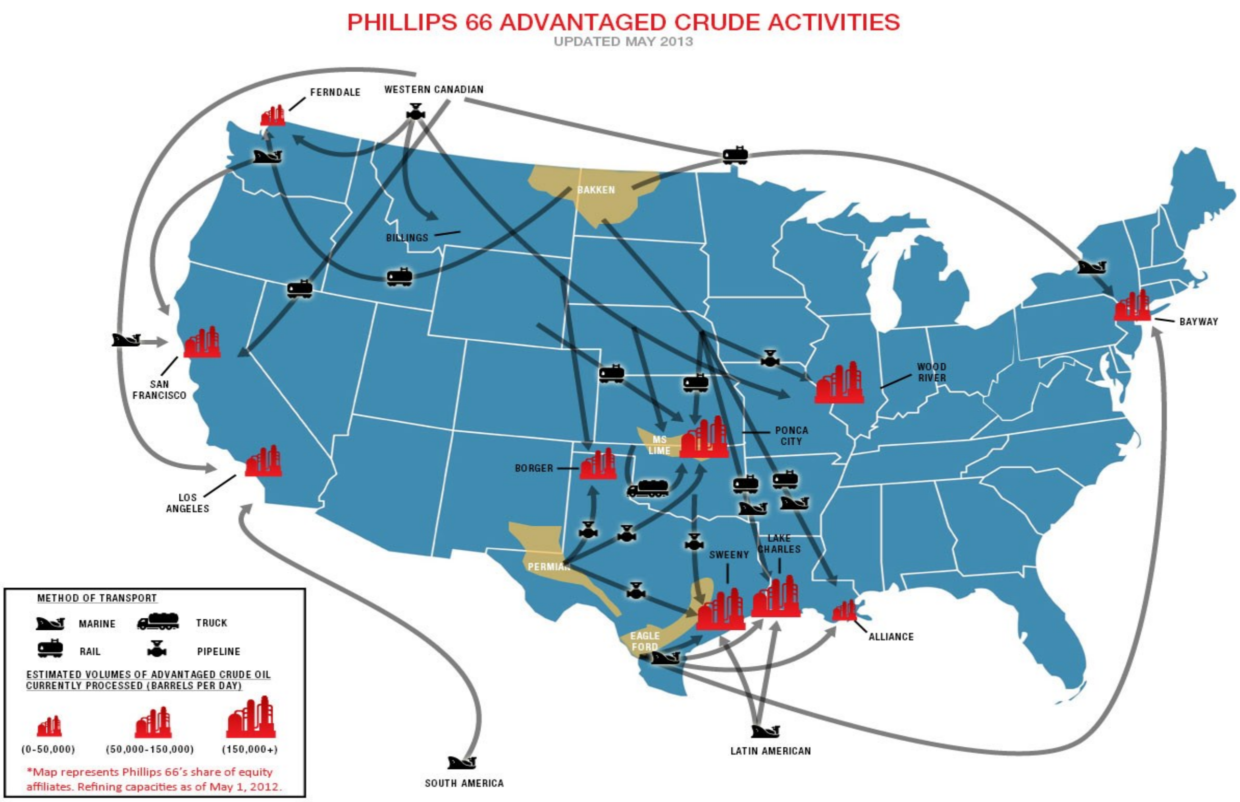
[10] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713, 730, quoting *County of Inyo v. City of Los Angeles* (1977) 71 Cal. App. 3d 185, 193.
[11] *Id.* at 730.
[12] *Id.* (citation omitted).
[13] *See* CEQA Guidelines, §15124 (requirements of an EIR).
[14] RDEIR at 2-1.
[15] Karras Revised Santa Maria Report, at 3.

Phillips 66 is currently in the process of implementing a series of projects to allow a switch to refining what its management, and now also the RDEIR, calls, “advantaged crude.” The company emphasizes: “(the) opportunity that we have…is to get…Canadian crudes down into California…We're looking at rail to barge to ship, down to the West Coast refineries...”[16] The map immediately below details this strategy.



Phillips 66 map indicating plans to transport Western Canadian crude oil to San Francisco Refinery.[17] Notice that the icon labeled “San Francisco” identifies the San Francisco Refinery, which includes the Santa Maria facility.

The company has no choice but to seek such an alternative supply of crude oil feedstock. As stated in the RDEIR:

> In the long-term, the need for the SMR rail project could be driven by declines in local production of crude oil that can be delivered by pipeline. Production from offshore Santa Barbara County (OCS crude) has been in decline for a number of years. Oil production in Santa Barbara County (both onshore and offshore) peaked at about 188,000 barrels in 1995 (County of Santa Barbara Energy Division website) and currently production is

[16] September 12, 2013 Transcript, pdf 7, available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/Barclays_091213_Final.pdf.

[17] Phillips 66 Advantaged Crude Activities: Updated May 2013, available at: http://www.phillips66.com/EN/Advantaged%20Crude/index.htm.

around 61,000 barrels per day for both onshore and offshore oil fields (BOEM Pacific Region and Drilling Edge websites).[18]

This decline in locally available crude stands in stark contrast to the Santa Maria facility's recent Throughput Expansion that enables the Santa Maria facility to process more crude oil. Certainly, the RDEIR makes a bold assertion: "Phillips 66 expects to continue to receive, blend and process a comparable range of crudes in the future."[19] At the same time, however, those diminishing local sources make up the "bulk" of the crude oil currently processed at the Santa Maria Refinery.[20]

As noted in one expert report, "built to tap local oil fields, the Santa Maria facility lacks infrastructure to receive crude via ship or rail. A pipeline system that connect the Santa Maria facility only to local oil fields "is currently the only way that the Phillips 66 refinery can receive crude oil.""[21] There is substantial evidence that declining local and regional crude production could greatly affect the operation of the Santa Maria facility.[22] If the facility's crude rate falls too far below the design specifications of its existing equipment, it cannot operate efficiently or profitably.[23] A more accurate project description must admit that the company is *replacing* one feedstock with another.

The distinction in crude oil feedstock matters. The chemical composition of raw materials that are processed by a refinery directly affect the amount and composition of the refinery's emissions.

> The amount and composition of sulfur in the crude slate, for example, ultimately determines the amount of [sulfur dioxide] that will be emitted from every fired source in the refinery and the amount of odiferous hydrogen sulfide and mercaptans that will be emitted from tanks, pumps, valves, and fittings. The composition of the crude slate establishes the CEQA baseline against which impacts must be measured.[24]

Other significant impacts, such as increased energy consumption, air emissions, toxic pollutant releases, flaring and catastrophic incident risks, are also entirely dependent on the quality of crude oil processed at the facility.[25] As detailed further below, a heavier crude oil feedstock has also been identified as a contributing factor to potentially catastrophic incidents at refineries, and a root cause of the August 6, 2012 fire at the Chevron Richmond Refinery.[26]

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[18] RDEIR at 2-36.
[19] *Id.* at 2-33.
[20] *Id.* at 2-35.
[21] Karras Revised Santa Maria Report at 4, citing RDEIR at 2-36.
[22] *Id.* at 5.
[23] *Id.*
[24] Fox Rodeo Report at 13.
[25] *See* Fox Rodeo Report, Fox Valero Report and Karras Rodeo Report at 11-13.
[26] *See* Chemical Safety Board, Chevron Richmond Refinery Interim Investigation Report, April 2013, available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf.

Any environmental review document for this Project must analyze the full scope of these impacts, and at least for the anticipated life of the project. A shift of this extent has far different consequences and impacts compared to the RDEIR's diminished purpose of merely "obtaining" these feedstocks or "continu[ing] to receive, blend and process a comparable range of crudes in the future."[27] The RDEIR insists, "it is speculative as to what if any local crude oil would be displaced." No such speculation is required:

> "…our plan promises…availability and supplies in North America…we're disappointed in the progress to permit our Santa Maria rail rack 40,000 a day, but we have – we're optimistic that we'll get that done. It just takes time in California to get these things permitted…we're making progress in terms of put advantaged crude to the front of our refineries in California."[28]

The company has expressed a clear priority to switch to refining tar sands at the SFR, a priority diminished by the RDEIR focus on merely transportation infrastructure. In fact, the Project is proposing to replace the **majority** of the current crude slate (2010-2012: 38,100 bbl/day) with up to 100% tar sands crudes.[29] Consequently, the DEIR's omission of this switch to a very different crude oil feedstock violates CEQA in leaving several significant impacts unanalyzed.[30] It is impossible to provide any intelligent evaluation of the potential environmental effects and risks to community and worker health and safety of partially refining Canadian tar sands in Santa Maria, unless the RDEIR *first* discloses the extent of the replacement of feedstock that the Project enables.[31] At a minimum, the RDEIR should have established how this Project would affect the scope and degree of the company's use of tar sands in Santa Maria and Rodeo and evaluate its resulting impacts.[32] The RDEIR should also states whether, and by at least an estimated degree how much, the current 2-7% of heavy Canadian crude oil suggested by the RDEIR to be tar sands and processed at the Santa Maria Refinery would increase. Indeed, the percentage lies at the other end of the spectrum, reflecting the "long-term replacement of declining local SMF crude supplies."[33] Until such adequate disclosure occurs, the Project Description is inaccurate, incomplete and renders the analysis of significant environmental impacts inherently unreliable.[34]

B. The Project Is Piecemealed.

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[27] RDEIR at 2-33.
[28] *See* Phillips 66 Presentation to Barclays CEO Energy
Power Conference, September 2014, *available a*t http://investor.phillips66.com/files/doc_presentations/2014/PSX-BarclaysCEOConfTransSept2014.pdf
[29] Fox Revised Santa Maria Report at 12.
[30] *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").
[31] *See Id*., see *also, Communities for a Better Environment v. City of Richmond* (2010) 184 Cal.App.4 70, 89 (holding that an EIR is insufficient where it obscures the project's enabling of a refinery to process heavier crude).
[32] *Id*.
[33] Karras Revised Santa Maria Report at 7.
[34] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 722 (the failure to include relevant information relating to a project's components precludes informed decision making, thwarting the goals of the EIR) and *see* Karras and Fox Revised Santa Maria Reports.

Phillips 66's Santa Maria and Rodeo refineries are interdependent. One cannot function without the other. If major reconfigurations occur at both facilities at the same time and those modifications require each other, then they must be part of the same project. CEQA requires that an EIR describe the entirety of a project, including reasonably foreseeable future actions that are part of it.[35] Illegally "chopping a large project into many little ones" creates a narrow view of a project and "fallacy of division…that is, overlooking a project's cumulative impact by separately focusing on isolated parts of the whole."[36] Certainly, any permit by permit review, where those permits constitute a larger project, forecloses this essential focus on cumulative impacts, and also, impacts to already overburdened and vulnerable populations.

In *Laurel Heights I*, the Supreme Court established the following test: while an EIR need not include speculation about future environmental consequences of a project, the "EIR must include an analysis of the environmental effects of future expansion or other action if: (1) it is a reasonably foreseeable consequence of the initial project; and (2) the future expansion or action will be significant in that it will likely change the scope or nature of the initial project or its environmental effect."[37] Under this standard, "the facts of each case will determine whether and to what extent an EIR must analyze future expansion or other action."[38] A project proponent must analyze future expansion and other such action in an EIR if there is "telling evidence" that the agency has either made decisions or formulated reasonably definite proposals as to such future activities.[39] Further, there must be discussion "in at least general terms" of the future activity, even if the project is contingent on uncertain occurrences.[40]

This rail spur expansion project wholly depends on both the throughput expansion project and the critical back end of the SFR, the Phillips 66 Rodeo Refinery. The SFR consists of two facilities linked by a 200-mile Phillips-owned pipeline. The Santa Maria facility is located in Arroyo Grande, in San Luis Obispo County, while the Rodeo facility is located in Rodeo, in Contra Costa County. As the Draft EIR noted, "the Santa Maria Refinery and the Rodeo Refinery, linked by the company's own pipeline, comprise the San Francisco Refinery…Semi-refined liquid products from the Santa Maria Refinery are sent by pipeline to the Rodeo Refinery for upgrading into finished petroleum products."[41] The refining processes at Phillips 66's Santa Maria and Rodeo facilities are integrated to a capacity that neither can achieve alone.[42] Further, Phillips 66 reports these two facilities as a single processing entity, the San Francisco Refinery, to industry and government monitors.[43]

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[35] CEQA Guidelines § 15378(a).
[36] *See* Bozung v. Local Agency Formation Commission , 13 Cal. 3d 263, 268 (1975) and McQueen v. Board of Directors of the Mid-Peninsula Regional Open Space District, 202 Cal. App. 3d 1136, 1143 (1988).
[37] *Laurel Heights I*, 47 Cal. 3d at 394-396.
[38] *Id.* at 396.
[39] Id. at 396-397.
[40] *Id.* at 398.
[41] DEIR at 2-3. Notably, the reference to the company ownership of the pipeline has been obscured in the RDEIR.
[42] *See* Karras Report on Phillips 66 Propane Recovery Project, September 2013, Exhibits 21 through 24. *Oil & Gas Journal*, 2012; and EIA Ref. Cap. 2013. See also orders R2-2011-0027 and R3- 2007-0002. Comparing the references shows "Rodeo" capacities reported to EIA include the Santa Maria facility, attached as part of Attachment A.
[43] *Id.*

The RDEIR's piecemealing of both ends of the same refinery is analogous to the facts of *Laurel Heights I*. In that case, the Supreme Court set aside an EIR for piecemealing the reasonably foreseeable second phase of a multi-phased project. The University of California, San Francisco, had proposed a project to expand into a new building, of which only about a third was initially available to the school. The EIR failed to analyze impacts related to occupying the remaining two thirds, even though it was wholly foreseeable that UCSF would occupy the entire building.[44] Here, Phillips 66 will obtain tar sands crude by rail, must eventually fully refine it for sale, and to do so requires the entire SFR, not only the Santa Maria or Rodeo facilities. Just as it was foreseeable for the University of California to occupy the whole building, it is at least equally foreseeable, if not a surety, that the Rodeo facility will fully refine tar sands imported to the Santa Maria facility.

In order for Phillips 66 to implement its "advantaged crude" strategy for the SFR, it requires three pieces: the Santa Maria Refinery Throughput Increase Project, the Rodeo Refinery Propane Fuel Recovery Project, and this Project. Imports of heavy Canadian tar sands are facilitated by the Throughput Increase project. Components of the Rodeo Propane Fuel Recovery Project lock the Rodeo Refinery into a change in oil feedstock processing tar sands anticipated by rail to the Santa Maria Refinery.[45] That lower quality feedstock, gas oils and naptha, is produced at Santa Maria and sent to Rodeo by pipeline, a pipeline owned by the same company.[46] These changes are inter-related, wholly anticipate each other, and together create significant impacts on the environment. This meets the two-part *Laurel Heights I* test and is far removed from court decisions that do not find a piecemealed project on account of an insufficient showing of this "necessity" element.[47]

The following analysis further highlights a larger project that is piecemealed and more appropriate for review under a programmatic level EIR.

(i) The Prior Throughput Expansion is Dependent on this Project.

In the *San Joaquin Raptor* case, the court held that the EIR for a residential development project was invalid because it failed to discuss expansion of the sewer system, even though the developer recognized the necessity for sewer expansion for the overall development project to

[44] *Laurel Heights I*, 47 Cal.3d at 393.
[45] *See* Karras and Fox Rodeo Reports and RDEIR at 2-32 (Fox Rodeo Report also attached as part of Attachment A).
[46] *Id.* and DEIR at 2-29.
[47] In *Communities for a Better Environment et al. v. City of Richmond et al.*, (184 Cal. App. 4th 70, 100-101 (2010)), the Court of Appeal addressed the piecemealing issue with respect to another refinery expansion project. In that case, the EIR for the expansion project identified the potentially significant cumulative impact of a hydrogen pipeline project, but did not provide a complete analysis of the pipeline project's impacts. The Court held that the pipeline project was not piecemealed, that it is a separate project from the overall expansion project. In so holding, the Court reasoned that the expansion and pipeline projects are independent – they perform *entirely different* functions. The Court focused on project objectives: the expansion project's objective was to access a wider range of crude oil and other feedstocks; the pipeline project's objective was to transport excess hydrogen, not required by the expansion project, to other hydrogen consumers in the Bay Area. Ultimately, the Court found that the expansion project did not "depend on" the pipeline project. Similarly, in *Berkeley Jets*, the Court rejected an argument that an airport development plan should have included "long-range plans for potential runway expansions." The Court held that these future expansion plans were neither a crucial element nor a foreseeable consequence of the development plan. (*Berkeley Keep Jets Over the Bay Comm. v. Board of Port Cmrs.*, 91 Cal. App. 4th 1344, 1361 (2010)).

proceed.[48] The RDEIR's assertions that the throughput expansion project is unrelated and not dependent on the Rail Spur Project are misleading and incorrect.[49] This Project wholly supports the throughput expansion. Just as in *San Joaquin Raptor*, the company has identified a necessity to respond to declining local crude supplies. This calls into question any initial need, without the ability to obtain crude by rail, to increase throughput capacity.

The Santa Maria throughput increase project increases, "…the volume of products leaving the Santa Maria facility for the Rodeo Refinery via pipeline."[50] Nevertheless, the RDEIR still maintains that, "the ability of the Santa Maria Refinery to operate at the maximum approved throughput level is based on the existing infrastructure and is not dependent on, or related to, the SMR Rail Project."[51] Yet, the RDEIR then admits that, "the bulk" of local crude oil sources is declining, and in the long term, could "drive" this rail spur project.[52] This begs the simple question: if local supply is declining, how can the Santa Maria Refinery operate at the maximum capacity, when it currently operates below capacity, independent of rail assisted imports? Trucking in crude is expensive. There is simply no way for the Santa Maria facility to obtain enough crude oil feedstock for its throughput expansion economically without any crude imports by rail, implicating this Project's rail spur extension. The need for this Rail Spur Project was, therefore, wholly foreseeable at the inception of the Throughput Increase Project.

Furthermore, the environmental review of this Project overlaps with the Throughput Expansion explicitly in two regards. First, the evaluation of several project impacts is based on not only the same analysis and data performed in the Throughput Increase Project EIR, but the actual conclusions of that EIR.[53]

Second, the inclusion of the Vertical Coastal Access component is particularly telling. In *Tuolumne County*, the Court found projects A and B piecemealed where project B's approval was a condition of approval of project A.[54] As a condition of approval of the Throughput Increase Project, Phillips 66 was required to provide a vertical public right of coastal access at the Santa Maria facility.[55] The RDEIR includes a programmatic environmental assessment of the Vertical Coastal Access requirement: approval of this rail spur extension project would also mean approval of the vertical coastal access condition. This echoes the facts of *Tuolumne County*. Evidently, the public must also be protected from the rail transport of hazardous materials, as well as the facility's partial refining and storage of those same hazardous materials. Not only was the need for the rail spur clearly foreseeable at the time of the throughput expansion, but the linked projects also implicate greater and significant environmental impacts of transporting and refining tar sands at the SFR. The two projects are piecemealed and integral to this greater design.

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[48] San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus, 27 Cal.App.4th 713, 729 (1994).
[49] *See eg.* DEIR at 2-29.
[50] S*ee* Fox Rodeo Report at 6, citing Throuput Project DEIR at ES-4, 2-25.
[51] RDEIR at 2-35.
[52] RDEIR at 2-32, 2-36.
[53] *See eg.* Tables 4.3.6, 4.3.7, 4.3.26.
[54] *Tuolumne County*, 155 Cal. App. 4th at 1214.
[55] *See* RDEIR at ES-17.

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(ii) The Phillips 66 Rodeo Refinery is Dependent on this Project.

> "Tar sands crudes are heavier and more viscous than the feedstock currently processed at either Rodeo or Santa Maria. These crudes are thus commonly blended with 25% to 30% diluent to facilitate transporting them by rail or pipeline. The blended crude is known as a "DilBit." The diluent is typically natural gas condensate, pentanes, or naphtha. The diluent can be readily separated and recovered as propane/butane at Rodeo."[56]

The Santa Maria Refinery Throughput Increase and Rail Spur Extension projects are intricately related to the propane/butane recovery project currently proposed at the company's Rodeo Refinery. The Rodeo project recovers propane and butane from the refining of crude oil at both Rodeo and Santa Maria.[57] The throughput increase at Santa Maria would necessarily be included in the streams from which propane and propane/butane would be recovered at the Rodeo Refinery and this increase would have been anticipated when the propane/butane project was being planned as the Land Use Application for the Santa Maria throughput increase project was filed in 2008, well in advance of the propane/butane project at Rodeo, the application for which was filed in 2012. An increased throughput of tar sands would arrive at the Santa Maria facility by rail, be converted into semi-refined products in the Santa Maria facility's distillation units and coker to yield gas oil and naptha, which would then be sent to the Rodeo facility, where propane and butane would be separated, contributing to the propane/butane slated for recovery by the Rodeo Propane Recovery Project.[58]

In addition, the Throughput Increase Project anticipates a 10% increase in throughput capacity, and therefore butane and propane feedstocks.[59] Even with the throughput increase, a discrepancy between the amount of propane and butane projected and currently recovered still exists, and is quite large, perhaps explained by the company's anticipated recovery and use of propane and butane-rich diluent in Canadian tar sands crude.

> In fact, most all of the cost-advantaged crudes flooding into the market will allow the Santa Maria facility to produce propane/butane rich, semi-refined products and the Rodeo Refinery to recover more propane and butane from them than available in their baseline crude slates.[60]

Moreover, this implicates direct transport of tar sands crude from the Santa Maria facility to the Rodeo facility by pipeline. This possibility is not precluded by the RDEIR's assertion that, "no crude oil or refined product would be transported out of the refinery by rail."[61] Further,

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[56] Fox Rodeo Report at 7.
[57] *See* Karras and Fox Rodeo Reports and Karras and Fox Revised Santa Maria Reports.
[58] *Id.*
[59] Fox Rodeo Report at 6, citing Throughput Increase Project EIR.
[60] Fox Revised Santa Maria Report at 6.
[61] RDEIR at ES-5.

some tar sands crudes are classified as a semi-refined product,[62] and therefore not relevant to that assertion.

Another link between the import of tar sands dilbit oils at Santa Maria for processing and the Rodeo project involves solving the problem of the disposition of the diluent used to transport the bitumen in these dilbits. Generally, plants that, like Santa Maria's, are not configured to process light crude in any quantity may need to consider disposing of the (very light) diluent, which may, for example, simply be returned for reuse as diluent in future dilbit imports. While such a solution may be economic for pipeline delivery systems it could be quite costly, and hazardous, if the diluent is returned by rail. However, this same diluent is LPG-rich, and presents an opportunity to increase the amount of propane and butane that could be recovered at Rodeo.[63] Furthermore, the refining of dilbits yields much greater amounts of naphtha, "the lighter component of the pressure distillate sent to Rodeo and one of the feedstocks for propane recovery."[64] The Rodeo project, by allowing Phillips to recover and sell that (LPG) portion of the diluent, could significantly improve the cost structure of the "Advantaged Crude" strategy to be implemented by the Project.

The RDEIR attempts to provide information to contradict the interdependence of the two parts of the SFR. The RDEIR alleges that, as vapor "pressure limits (of tanks that store naphtha and gas oil) restrict the amount of propane/butane that can be contained in naphtha and gas oils," and, "additional butane and or propane would cause the products to exceed the vapor pressure limits of the storage tanks," suggesting that there is no link between this Project and the Rodeo project.[65] The RDEIR attempts to bolster this claim by asserting that it historically and currently operates near these limits, prohibiting any potential increased propane/butane transport to Rodeo.[66] These assertions, however, are incorrect and wrong.[67] Rather, there are either no such vapor pressure limits on the subject tanks, or the materials stored in them have a vapor pressure far below their permitted levels.[68] In addition, the RDEIR fails to contain any support whatsoever for these propositions, which cannot meet CEQA's threshold requirement of substantial evidence.[69] "In sum, the claims made in the RDEIRs in an attempt to decouple the Santa Maria Rail Spur Project and the Rodeo Propane Recovery Project based on vapor pressure limits have no merit."[70]

Evidently, plenty of "telling evidence" exists regarding the intimate connection between the proposed Project, the Throughput Increase Project and the Propane Recovery Project. The facts are again analogous to *Laurel Heights I* and the *San Joaquin Raptor* case: the Rodeo Project depends on the projects at the Santa Maria Facility and vice versa. Consequently, these

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[62] Fox Rodeo Report at 6.
[63] Fox Revised Santa Maria Report at 7.
[64] *Id*. at 8, citing RDEIR for the Propane Recovery Project at 3-6.
[65] *Id.* at 2.
[66] *Id.*
[67] *Id.*
[68] *Id.*
[69] *Id.* at 3.
[70] *Id.* at 11.

are connected actions that must therefore be analyzed concurrently with the direct and cumulative impacts of the proposed Project itself under a programmatic EIR assessment.[71]

Finally, under CEQA, even assuming, arguendo, that the Rodeo Propane Recovery project is not an integral part of this proposed Project, the RDEIR still failed to adequately discuss the Rodeo project, and should at a minimum have discussed the need to recover propane or butane from sources facilitated by the rail spur expansion.[72] The company's ownership of the pipeline gives the company proprietary rights and ownership of all shipments. The impacts are cumulatively considerable and should have been assessed in the RDEIR.

(iii) Both the Rail Spur Extension Project and the Propane Recovery Project Lack any Independent Utility.

Under California law, where one part of an arguably larger project serves some "independent utility," the lead agency may focus solely on that smaller part of the project.[73] For the reasons detailed above, however, this Project, the rail spur extension, bears no independent utility. The project is piecemealed and the County should review the overall impacts, especially the cumulative impacts, of the larger project.

III. THE RDEIR'S PREEMPTION ASSERTIONS PRECLUDE A MEANINGFUL ANALYSIS OF PROJECT IMPACTS.

The DEIR erroneously purports that mitigation is preempted by federal law, thereby avoiding critical measures to abate the hazards and impacts of increased crude by rail transport through California Communities.

The RDEIR states that:

> The operation of unit and manifest trains to and from the Rail Spur Project Site would be performed by UPRR, on UPRR property, and on trains operated by UPRR employees. The movement of those trains within San Luis Obispo County to and from the Project Site … may be preempted from local and state environmental regulations by federal law under the Interstate Commerce Commission Termination Act of 1995 … the County as CEQA Lead Agency, and other state and local responsible agencies may be preempted from imposing mitigation measures, conditions or regulations to reduce or mitigate potential impacts of UPRR train movements on the mainline.[74]

Similar statements to this effect are repeated throughout the RDEIR.[75]

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[71] CEQA Guidelines, § 15378, subd. (a) agency must evaluate the environmental impacts of the whole of the action.
[72] *Laurel Heights I*, 47 Cal.3d at 398 (requiring discussion "in at least general terms" of future activity in connection with a project, even if the project is contingent on uncertain occurrences).
[73] Del Mar Terrace Conservancy, Inc. v. City Council of San Diego, 10 Cal. App. 4th 712 (1992).
[74] EIR at ES-22.
[75] *See, e.g.*, RDEIR at ES-6, 1-7, 1-8, 2-2, 4-1. The EIR correctly states that mitigation addressing impacts, including air emissions, within the SMR facility boundaries can be mitigated because Phillips 66 controls and operates the facility property. EIR at ES-9; 4.3-5. *See Town of Milford, MA – Petition for Declaratory Order*, STB F.C.C. No.

With little justification or analysis, the RDEIR concludes on several occasions that the impacts of the proposed project will be "significant and unavoidable" because mitigation required by the County as it applies to the mainline and UPRR locomotives may be preempted and therefore unenforceable. The RDEIR reaches the "significant and unavoidable" conclusion based on preemption for a range of impacts caused by the project. Specifically, the RDEIR states that the following mitigation measures could be preempted by federal law:

- Measures to improve emergency response and oil spill clean-up along the mainline to reduce impacts to adjacent agricultural crops, sensitive biological and cultural resources, and ground and surface water resources.[76]
- Mitigation measures imposed along the mainline tracks addressing emergency responder notification and training.[77]
- Mitigation measures to require the use of Tier 4 locomotives outside the SMR property to address emissions from locomotives, including cancer-causing toxic emissions, which will result in exceedances of air district thresholds along the mainline.[78]
- Mitigation measures that would reduce greenhouse gas emissions associated with locomotives outside the SMR property.[79]
- Mitigation addressing tank car design safety applied to the mainline and UPRR locomotives by the County.[80, 81]

For the following three reasons, the RDEIR's analysis is inadequate and too limited to provide any proper or suitable mitigation.

1. The Interstate Commerce Commission Termination Act Preemption is Not Unlimited.

34444, 2004 WL 1802301, at *2 (S.T.B., Aug. 11, 2004)(when railroads involvement in rail terminal transloading facility owned by a third party is incidental to terminal operations, STB has no authority, [therefore state has full authority over CEQA review of the proposed SMR project]); *High Tech Trans, LLC – Petition for Declaratory Order*, STB F.D. No. 34192, 2003 WL 21952136, at *1 (S.T.B., Aug. 14, 2003)(railroad delivered cars, but transloading facility owned and operated by a non-railroad third party).

[76] EIR at ES-8; ES-10; ES-14; 4.4-47, 48; 4.5-15; 4.7-63; 4.8-26; 4.13-28.

[77] EIR at ES-13; 4.4-47, 48; 4.11-29, 32.

[78] EIR at ES-9; 4.3-5, 48, 50, 56, 63, 67, 68, 75, 76; 5-44, 48.

[79] EIR at ES-9; 4.3-71, 77.

[80] EIR at ES-11; 4.4-47, 48; 4.13-28; 5-48; 51.

[81] The EIR cannot simply rely on the U.S. Department of Transportation's rulemaking to ensure safer tank car designs will serve the project and reduce the hazards of crude by rail transport. That rulemaking proposes several alternatives for new tank car designs, which reduce risks of crude by rail transport to varying degrees, and that rulemaking has not yet been finalized. Therefore, there is significant uncertainty about the degree of safety and risk reduction that will result from the final rule. Moreover, implementation of a final rule, including a phase out of the most dangerous tank cars including DOT111s and unjacketed CPC-1232s, may take as long as six years. As such, the safety benefits of the proposed rule will not materialize until long after the proposed SMR project would begin operation. In the meantime, the U.S. DOT estimates that under the current rail infrastructure network, 15 mainline accidents spilling crude will occur each year and at least one disastrous incident at least as large as Lac Megantic will occur every two years.

Simply concluding that mitigation may be unenforceable and the project's impacts are "significant and unavoidable" because mitigation may be preempted by federal law is a misinterpretation of the intersection between CEQA and ICCTA. As such, failing to require and enforce mitigation is an abdication of the County's responsibilities under CEQA.

The Interstate Commerce Commission Termination Act gives the Surface Transportation Board economic regulatory oversight over the railroad industry, including rates; service; the construction, acquisition and abandonment of rail lines, carrier mergers; and interchange of traffic among carriers.[82] Although the ICCTA provides exclusive authority by the Surface Transportation Board over many aspects of rail transport, the scope of that preemption authority is not limitless.[83] Citing decisions from federal appellate courts, the *Humboldt Baykeeper* court reiterated that ICCTA preemption applies only to state laws "with respect to regulation of rail transportation."[84]

Moreover, state and local entities can implement railroad safety regulations or measures if they are necessary to eliminate an "essentially local safety hazard," and are not incompatible with federal regulations, or unduly burden interstate commerce.[85] Importantly, a state or local requirement must not impact an activity that is integral to railroad operations and must not impose a significant burden on railroad operations.

Courts also have concluded that the ICCTA does not preempt CEQA.[86] Nor does CEQA, which is an informational statute, "unreasonably interfere with interstate commerce."[87] CEQA, which does not regulate rail transportation, is an environmental review law of general application that applies to projects in California that may have a significant effect on the environment. CEQA requires that significant impacts of a project be mitigated if reasonably feasible. A local

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[82] 49 U.S.C. § 10101 *et seq.*

[83] *Humboldt Baykeeper v. Union Pacific RR*, 2010 WL 2179900, *2(N.D. Cal. May 27, 2010).

[84] *Id.* ("ICCTA preemption only displaces "'regulation,' i.e., those state laws that may reasonably be said to have the effect of 'managing]' or 'governing]' rail transportation" and permits "the continued application of laws having a more remote or incidental effect on rail transportation."); s*ee e.g., Fla. E. Coast Ry. Co. v. City of West Palm Beach*, 266 F.3d 1324 (11th Cir. 2001)(application of local zoning and occupational license ordinances against a company leasing property from a railroad does not constitute "regulation of rail transportation" and is not preempted by the ICCTA); *Flynn v. Burlington Northern Santa Fe Corporation*, 98 F. Supp. 2d 1186, 1189-90 (E.D. Wash. 200)(noting that "ancillary railroad operations" such as "truck transfer facilities" are not subject to federal preemption); *Californians for Alternatives to Toxics v. N. Coast R.R. Auth. Et al*, 2012 WL 1610756 (N.D. Cal., May 8, 2012).

[85] 49 U.S.C. 20106(a). *See, e.g., Southern Pacific Transportation Company v. Public Utility Commission of the State of Oregon*, 9 F.3d 807, 812 (9th Cir. 1993); *State of Washington v. Chicago, Milwaukee, St. Paul and Pacific Railroad Company*, 79 Wn.2d 288 (Wash. 1971)(upholding local regulation forbidding the operation of engines without modern spark plug arrestors to prevent fires which are characterized as an essentially local safety hazard). *Flynn v. Burlington N. Santa Fe Corp. (BNSF),* 98 F. Supp. 2d 1186, 1189 (E.D. Wash. 2000) (local authorities can exercise their police powers to protect local community health and safety).

[86] *Humboldt Baykeeper v. Union Pacific RR*, 2010 WL 2179900, *2(N.D. Cal. May 27, 2010); *Town of Atherton v. California High-Speed Rail Auth.,* 228 Cal. App. 4th 314, 330-31, 175 Cal. Rptr. 3d 145, 159-60 (2014) (relying on market participant doctrine); and s*ee generally Ass'n of American Railroads v. South Coast Air Quality Management District*, 622 F.3d 1094, 1097 (9th Cir. 2010). *But see Friends of the Eel River v. N. Coast R.R. Auth.* (Sept. 29, 2014, !st Dist. Ct. App., Case No. A139235), *available at* http://www.courts.ca.gov/opinions/documents/A139222.PDF.

[87] *Id.*

government's environmental and health policy goals to achieve efficient and safe market participation are perfectly acceptable policies through which to enforce mitigation measures that abate the externalities of increased volatile and toxic crude by rail service through communities.[88]

Without analysis, the RDEIR erroneously concludes that mitigation along the mainline is infeasible because it may be preempted. However, a factual assessment of the Project's proposed mitigation, which is absent from the RDEIR, demonstrates that mitigation measures to abate serious local and regional air quality problems and to adequately prepare for local emergency response and spill planning do not "unreasonably interfere with railroad transportation" and therefore are not preempted.[89]

2. CEQA Mitigation is Necessary to Abate Serious Public Health and Safety Impacts Posed by the Project and is not Preempted by the ICCTA.

Proposed mitigation along the mainline directly addresses the local safety and environmental threats posed by the movement of hazardous crude by rail through communities. In particular, the burden of increased air pollution emissions from locomotives and tank cars—including volatile organic compounds and cancer-causing toxic air pollutants—on communities already adversely impacted by poor air quality present a significant local safety concern. Environmental justice communities along the mainline rail route including Richmond, Oakland, and Martinez, and cities throughout California's Central Valley already experience increased adverse health effects from poor local air quality, making mitigation of locomotive air emissions even more critical. Accordingly, the mitigation of air emissions proposed in the RDEIR and other measures not proposed but urgently needed to limit VOC and GHG releases from tank cars must be required and enforced to abate the heightened health and safety risks created by multiple mile-long crude trains traveling through highly impacted communities.[90] Notably, mitigation of tank cars, all of which are owned by Phillips 66,[91] to prevent release of VOCs and greenhouse gases can be implemented even before the cars are handed off to UPRR for operation during transport.

Indeed, requirements of locomotives and tank cars to reduce dangerous air pollution along the mainline do not "deny [the] railroad the ability to conduct some part of its operations", nor does such mitigation interfere with matters "directly regulated" by the Surface Transportation Board, such as "construction, operation, and abandonment of rail lines; railroad mergers, line acquisitions, and other forms of consolidation; and railroad rates and service."[92] Moreover, such mitigation "can be obeyed with reasonable certainty" and avoid "extended or open-ended delays."[93]

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88 *Town of Atherton v. California High-Speed Rail Auth.,* 228 Cal. App. 4th 314, 330-31, 175 Cal. Rptr. 3d 145, 159-60 (2014).
89 *Id.* at 164.
90 EIR at ES-9; 4.3-5, 48, 50, 56, 63, 67, 68, 75, 76; 5-44, 48.
91 EIR at ES-5.
92 *Town of Atherton v. California High-Speed Rail Auth.,* 228 Cal. App. 4th 314, 330-31, 175 Cal. Rptr. 3d 145, 159-60 (2014).
93 *Green Mountain R.R. Corp. v. Vermont* (2nd. Cir. 2005) 404 F.3d 638, 643.

Similarly, mitigation addressing emergency response—including notification and training of first responders and coordinated oil spill clean-up and incident response planning—are critical measures that must be taken to address serious safety risks. These risks include risk of derailments and spills that threaten contamination of entire drinking water sources and destruction of downtown urban areas, as well as agricultural, cultural, and sensitive biological resources.[94] Indeed, the warnings by the National Transportation Safety Board and the record evidence in the U.S. Department of Transportation crude rail safety rulemaking demonstrate that crude by rail transport in DOT111 and unjacketed CPC 1232 tank cars (proposed for use in this project) is high risk. Damages from derailments, resulting in fires, explosions and spills are extremely damaging and costly to clean up. The risks are especially exacerbated for communities along the rail lines that bear the burden of catastrophic damages from accidents. These mitigation measures do not deny UPRR from continuing to provide service, nor do such measures "discriminate" or "unduly burden" rail transport serving the SMR project. Accordingly, these measures must be required and enforced to abate heightened local safety problems.[95, 96]

3. ICCTA Preemption is Improper because it Undermines a Local Government's Ability to Comply with other Federal Statutes.

Further, preemption by the ICCTA is improper because mitigation within the SMR facility and along the mainline is necessary to ensure compliance with other federal statutes such as the Clean Air Act and Clean Water Act.[97] Specifically, air pollution mitigation to reduce toxic cancer-causing emissions must be required to ensure Clean Air Act pollution thresholds are not exceeded.[98] In addition, much of California is nonattainment for state and federal Clean Air Act ozone and PM2.5 standards. The cumulative impacts of locomotives supporting the many crude by rail projects proposed or in operation in the state would significantly interfere with compliance of Clean Air Act ozone and PM2.5 standards as well as meeting Regional Haze requirements.[99] As such, absent mitigation on locomotive emissions, the additional air pollution from trains serving the proposed project would impede compliance with these federal standards.

Further, oil spill response planning, including training and notification, is necessary to fulfill local governmental responsibilities under the Clean Water Act. The federal statute, amended in 1990 by the Oil Pollution Act, includes mandates that preserve the authority of state and local governments to impose additional oil spill prevention and clean-up requirements.[100] Accordingly, mitigation measures that advance the Clean Water Act's mandates of oil spill

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[94] EIR at 4.5-14; 4.7-63; 4.13-28.
[95] *Id.* at 160,162.
[96] The DEIR must not simply rely on California law AB861 for additional forms of emergency response mitigation as that law is under attack by the rail industry and the subject of a legal challenge. Moreover, that law does not address the particular safety needs of individual communities and water sources along the mainline. As such, additional mitigation measures addressing local emergency response and spill prevention must be required.
[97] *Flynn v. Burlington N. Santa Fe Corp. (BNSF),* 98 F. Supp. 2d 1186, 1189 (E.D. Wash. 2000).
[98] EIR at 4.3-50.
[99] *See* http://www.arb.ca.gov/desig/desig.htm. In addition, the California compliance plan for Regional Haze under the Clean Air Act includes phasing in new locomotive engines. *See* Table 1 of: Progress Report at: http://www.arb.ca.gov/planning/reghaze/progress/carhpr2014.pdf.
[100] 33 U.S.C. § 1321(o)(1)-(2).

prevention and effective response are necessary and enforceable in communities directly impacted by crude transport servicing the proposed project.

In sum, while the ICCTA may preempt some state laws and regulations, it is not a blanket preemption that applies to every state law or regulation that touches on railroads in any way. The RDEIR has unlawfully dismissed critical mitigation measures to protect the public health, safety and environment of California communities directly impacted by the proposed project. The RDEIR does not cite any authority that supports the position that CEQA mitigation is preempted by ICCTA. The RDEIR's statements of federal preemption are overly broad and simplistic, and fail to recognize the nuance in preemption questions, especially when state police power to protect the public health and safety are involved. Consequently, the RDEIR's analysis has not satisfied the legal requirements under CEQA for "significant and unavoidable" impacts. These flaws compound the many other inadequacies of the RDEIR's impacts analysis as detailed immediately below.

IV. THE DEIR'S ANALYSIS OF AND MITIGATION FOR THE IMPACTS OF THE PROPOSED PROJECT ARE INADEQUATE.

In order to effectuate the fundamental purpose of CEQA, it is critical that an EIR meaningfully inform the public and its responsible officials of the environmental consequences of their decisions *before* they are made."[101] Only with a genuine, good faith disclosure of a proposed project's components, can a lead Agency analyze the full range of potential impacts of the project, identify, and implement mitigation measures where necessary, prior to project approval.[102]

Nevertheless, because the RDEIR still fails to include integral project components and the SFR's overall switch to tar sands in its analyses, the RDEIR still asks the wrong questions, diminishing or even foreclosing an analysis of the Project's environmental impacts, even those it determines to be significant. In several of those instances, the RDEIR lacks the necessary detail to verify the validity of its analyses. Consequently, the RDEIR fails to include a sufficient analysis of the Project's impacts as required by CEQA.[103] These include significant and unmitigated impacts to: air quality, public and worker health and safety, water quality and supply, agriculture, biological resources and the local community in the Nipomo Mesa area.

A. The DEIR Fails to Adequately Analyze and Mitigate the Project's Air Quality Impacts.

The RDEIR's analysis of the Project's criteria pollutant impacts is riddled with errors.

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[101] *Laurel Heights Improvement Ass'n v. Regents of University of California* (1993) 6 Cal. 4th 1112, 1123; CEQA Guidelines § 15126.2(a) ("[a]n EIR *shall* identify and focus on the significant environmental effects of the proposed project") (emphasis added throughout).

[102] 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.

[103] *See*, *Laurel Heights Improvement Assn. v. Regents of Univ. of California, supra,* 47 Cal.3d, at 400 (*quoting* Pub. Resources Code § 21002.1(a); and Guidelines 15002(a)). *See also*, *Communities for a Better Environment v. Richmond, supra*, 184 Cal.App.4th, at 89 (an "EIR must include forseeable change in crude processed as part of environmental and impacts analysis.").

We highlight several: first, the EIR relies on an inadequate study area and therefore underestimates the Project's potential to result in a substantial increase in criteria pollutant emissions. Second, the RDEIR's analysis is predicated on a vague, faulty and illegal baseline. Third, the RDEIR's analysis ignores any increase in toxic or hazardous air pollutants from the increased refining of tar sands. Fourth, the RDEIR does not analyze all of the project's components. Fifth, the Project's climate change implications are completely underestimated. Sixth, the RDEIR's analysis relies on an illegal use of Emission Reduction Credits. Finally, the EIR fails to properly address emissions from construction activities. The end result is that the Project will result in significant air quality impacts that the EIR fails to identify or mitigate.

(i) The DEIR Incorporates an Inadequate Study Area.

The study area of an EIR must include "the area which will be affected by a proposed project."[104] There is no predefined geographic limit to where impacts can occur, and it is well established that "the area that will be affected by a proposed project may be greater than the area encompassed by the project itself."[105] This broad understanding of the geographic scope of an EIR's analysis is essential, and "the purpose of CEQA would be undermined if the appropriate governmental agencies went forward without an awareness of the effects a project will have on areas outside of the boundaries of the project area."[106]

The RDEIR still substantially underestimates the Project's increase in greenhouse gas ("GHG") and criteria air pollutant emissions because it relies on an artificially and unnecessarily constrained study area. The DEIR's air impact analysis is unnecessarily limited to the immediate vicinity of the Rail Spur.[107] Our prior comments[108] made this same observation. The RDEIR attempts to ameliorate the deficiency by employing significance criteria from the SLOCAPCD CEQA Air Quality Handbook.[109] The Handbook, however, emphasizes the necessity for a "complete and accurate project description," and full disclosure of potential air pollutants and toxic air contaminants."[110] The RDEIR cannot use the Handbook as any measuring stick until it adequately discloses the full scope and impacts of this Project.

Furthermore, as noted throughout this comment, the air quality impacts of the Project will regularly extend far beyond the county line. By artificially limiting the geographic scope of the analysis to air pollutants emitted within the boundaries of San Luis Obispo County, the RDEIR substantially underestimates the significant air quality impacts of refining tar sands at the SFR. The RDEIR should be revised to evaluate these Project emissions that occur in and outside of the County, and to discuss mitigation for those emissions.

(ii) The DEIR Uses an Inappropriate Baseline Environmental Setting, Rendering its Air Quality Analysis Unreliable.

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[104] *See* Cal. Pub. Res. Code § 21060.5 (defining "environment" as "the physical conditions that exist within the area which will be affected by a proposed project").
[105] *Save the Plastic Bag Coalition v. City of Manhattan Beach* (2011) 52 Cal.4th 155, 173.
[106] Muzzy Ranch Co. v. Solano Cnty. Airport Land Use Com. (2007) 41 Cal. 4th 372, 387.
[107] RDEIR at 4-2.
[108] *See* Attachment C.
[109] RDEIR at 4.3-33.
[110] *See* SLOCAPCD CEQA Air Quality Handbook at 1-3.

The RDEIR's baseline is vague. It is not clear what baseline the RDEIR uses, but to any degree, relies on permitted levels. This reliance on permit limitations instead of actual emissions to establish baseline air quality is a clear violation of CEQA. This precise discrepancy was at issue in *Communities for a Better Environment v. South Coast Air Quality Management District*, where the Supreme Court rejected the Air District's argument that permit levels should be used to establish the baseline.[111] The Air District argued that for a project employing existing equipment, the baseline should be the maximum permitted operating capacity of the equipment, even if the equipment is operating below those levels when the Notice of Preparation is issued.[112] The Supreme Court rejected the District's illegal permit based approach, and clarified the need for the proper assessment of baseline for review under CEQA.[113] The County should similarly reject the RDEIR's use of a vague and illegal baseline that also employs measurements from another piece of the same larger project, further corroborating that this Project is piecemealed.

(iii) The DEIR Fails to Identify or Mitigate Additional Impacts of Emissions Resulting from the Project's Change in Crude Slate.

The RDEIR fails to analyze the increase in Toxic Air Contaminants ("TACs") and Hazardous Air Pollutants ("HAPs") from refining tar sands. As mentioned throughout this comment, the expert reports, and the comments and expert reports to the DEIR, tar sands crudes are distinct from even the heaviest of crudes processed in the past at the SMR, for two principal reasons: (1) the unique chemical composition of the bitumen itself; and (2) the presence of large quantities of volatile diluent containing high levels of VOCs, TACs and HAPs. When released, these air pollutants cause significant public health and air quality impacts that are inadequately addressed in the RDEIR.[114]

TAC and HAP emissions in "DilBit"

Tar sands crudes alone are comprised of higher molecular weight chemicals than the current slate processed at the SMR, including large amounts of benzene, toluene, ethyl-benzene, xylenes,[115] and other heavy metals such as lead. These chemicals are found in both state and federal toxic emissions inventories, and are, therefore, of particular concern to both federal and state regulatory agencies.[116] As stated in CBE's Comments to the DEIR, the U.S. Geological Survey reports that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil.[117]

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[111] *Communities for a Better Env't v. S. Coast Air Quality Management District* (*CBE v. SCAQMD*) (2010) 48 Cal. 4th 310.
[112] *CBE v. SCAQMD*, 48 Cal. 4th at 320.
[113] *Id.*
[114] To the extent the RDEIR fails to cure errors regarding the Project's public health impacts, raised by CBE in its comment to the DEIR, the same comments are hereby incorporated by reference.
[115] Together referred to as "BTEX" compounds.
[116] *See, e.g.*, United States EPA, Clean Air Act 1990 List of Hazardous Air Pollutants, available at: http://www.epa.gov/ttn/atw/orig189.html, last accessed on Jan 26, 2014; *see also*, California Air Resources Board Toxic air Contaminant Identification List, available at: http://www.arb.ca.gov/toxics/cattable.htm#Note 1, last accessed on Jan 26, 2014.
[117] *See*, Fox Report to DEIR.

When blended with the diluents, tar sands "dilbit" crudes contain even higher concentrations of BTEX compounds, which have a significantly high potential to be released by way of transport and process related emissions that also remain underestimated in the RDEIR. These contaminants can cause severe impacts on the environment, and can lead to grave human health problems. Moreover, because diluents also have a notably low molecular weight, and a high vapor pressure, they are highly prone to cause fugitive, gaseous releases by increasing vapor pressure in various refinery operation components throughout the SFR, including rail cars and pipelines used for transport to and between the Santa Maria and Rodeo facilities.[118]

Potential and Known Public Health Impacts

Despite the known severe health effects of the HAPs including BTEX compounds present in "DilBit" crudes, the RDEIR incorporates a number of assumptions and flawed emissions estimates that lead to a faulty analysis of the range of significant impacts from their release into the environment, and as a result the RDEIR fails to state adequate mitigation.[119] While the RDEIR now acknowledges the shift in the overall crude slate that will be enabled by the Project, and discloses the fact that Phillips 66 currently processes only a small portion of Canadian tar sands crudes,[120] the document still fails to address potentially severe impacts from Project emissions including the range of potential health impacts from known carcinogens and other harmful pollutants; acid rain; bioaccumulation of the toxic contaminants contained in the Project's potential emissions; the formation of ground-level ozone and smog; visibility impairments; odor impacts affecting residents near the Refinery; accidental releases due to corrosion of refinery equipment; and depletion of soil nutrients.[121]

As discussed in CBE's comments on the DEIR, benzene alone has notably high cancer potency, and is known to cause severe reproductive, developmental and immune systems impacts at even low exposure levels.[122] Systemic benzene poisoning, a long term exposure risk, includes the potential for severe hemorrhages, and may at times result in fatality.[123] Concentrated, acute exposure levels have also been known to cause headaches, and nausea.[124] While less information is available relating to longer term systemic and acute exposure levels to ethylbenzene, toluene and xylene, in California, the toxicity and risk levels of the three are currently under CARB scientific review.[125]

Flaws in the RDEIR's Analysis of Impacts to Public Health

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[118] *See* Fox Report to DEIR, at 22 (explaining that these contaminants are present in highly dangerous concentrations in "DilBits" as a result of their composition of both undiluted tar sands bitumen crudes and diluent mixtures.).
[119] RDEIR 4.3-59.
[120] RDEIR 2-33.
[121] *Id*.
[122] Determination of Acute Reference Exposure Levels for Airborne Toxicants, March 1999, Acute Toxic Summary, BENZENE, available at: http://www.oehha.ca.gov/air/acute_rels/pdf/71432A.pdf, last accessed, November 24, 2014.
[123] *Id*.
[124] *Id*.
[125] California Air Resources Board, Toxic Air Contaminant Identification List, available at: http://www.arb.ca.gov/toxics/cattable.htm#Note 1, last accessed, November 24, 2014.

While the RDEIR incorporates the Health Risk Assessment (HRA) conducted in the Environmental Review process and its relative cancer risk assessments, it fails to identify, analyze or mitigate, the associated, **non**-cancer causing, potentially severe public health risks resulting from both construction and operation of the project, and from both the transport and refining activities enabled Project operations.

The RDEIR assumes an increase of BTEX compound emissions at the SMR from 0.81 to 1.25%, and it defines and analyzes the scope as well as the relative significance of this increase in terms of "the probability of developing cancer" as a result of "exposure to a given chemical, at a given concentration." [126] By referring exclusively to the HRA to analyze the Project's impacts resulting from increased BTEX emissions,[127] the RDEIR concludes that the increase in BTEX levels at the facility affect both acute and chronic cancer risk levels only *minimally*, with a 0.03 and 0.002 increase in each, respectively, with the highest risk occurring at the SMR parcel boundary immediately south and west of the rail spur location due to diesel emissions from the rail spur operations, which the RDEIR further concludes is "not a significant impact because no residential receptors are located there."[128] Indeed, the highest cancer risk reported in the RDEIR, and the in the HRA occurs north of the facility primarily due to the current trucking diesel emissions at residential receptors.[129]

The RDEIR cannot solely rely on the HRA's assessment of relative cancer risk to determine the level of significance of potential TAC and HAP emissions, and provide adequate mitigation and the fact that is does so, violates CEQA's requirement to include a sufficient analysis of local, direct, indirect and cumulative impacts.[130]

As explained above, BTEX compounds known to be present in high concentrations in "DilBit" both in combination and each separately, present serious, non-cancer risks that must be independently analyzed. Moreover the RDEIR's analysis is focused on the areas directly adjacent to the Project area, precluding the document's analysis of increased public health risks caused by transport along the rail lines, and by refining at the Rodeo facility. The RDEIR must analyze and mitigate these impacts, as they are not otherwise analyzed for the purpose of meeting CEQA's requirements in the HRA.

The RDEIR further fails to state other, specific information necessary to assess the potential human health impacts from the Project, such as information regarding the concentration of diluents that will be present in those crudes, resulting in the public's need to guess, based on outside information, what an approximate mix of diluents to tar-sands bitumen might be. Readers of an EIR should not be forced to rely on outside research and resources to find important components of a thorough environmental analysis.[131] Information regarding the

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[126] RDEIR 4.3-60.
[127] *Id*.
[128] RDEIR 4.3-61 (emphasis added).
[129] *Id*.
[130] *See*, *Laurel Heights Improvement Assn. v. Regents of Univ. of California, supra,* 47 Cal.3d, at 400 (*quoting* Pub. Resources Code § 21002.1(a); and Guidelines 15002(a)).
[131] *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.

concentration of heavy metals, chemicals and organic compounds contained in the crude is critical to assessing the scope and extent of impacts from potential emissions caused by these crudes, and impacting public health in the areas surrounding the San Francisco Refinery facilities. While we may conjure the amount of diluents and tar sands blend used at the Refinery, through piecing together other data, it is a grave problem that the precise amount of diluents used to transport, store or otherwise process tar sands crudes arriving at the Santa Maria facility by rail is entirely omitted from the RDEIR analysis.

Moreover, the RDEIR fully omits any impact analysis for other harmful, air pollutants such as lead, which the California Air Resources Board (CARB) and the Center For Disease Control have identified as a pollutant for which there is no safe level of exposure.[132] Indeed, the RDEIR fails to even state a baseline level for the current level of lead emissions, upon which any additional increase must be measured. In comments to the DEIR, CBE pointed out that based on CARB's findings the increase in lead from switching even a minimal percentage of the Refinery's current crude slate to tar sands alone is a significant impact.[133] Yet the RDEIR continues to omit any mention of the Project's potential to drastically increase lead emissions, by shifting the Refinery's overall crude slate. The potential health impacts from led are, moreover, deeply concerning, as they can include serious, permanent neurological damage, particularly in children. The RDEIR's failure to identify, much less analyze or mitigate this category of known potential impacts stemming from the change in crude slate enabled by the project, therefore, highlights one, crucial example of the failings of the RDEIR, which must be corrected, in a revised, and re-circulated document.[134]

The RDEIR Fails to Identify, Analyze and Mitigate the Cumulative Impacts Caused by TAC and HAP Emissions at the Rodeo Refinery

Finally, because the Project's crude slate change will increase TAC and HAP emissions from **all** fugitive components in the Refinery, including both the Santa Maria and Rodeo facilities; through compressors, pumps, valves, fittings, and tanks, in far greater amounts than from the current baseline feedstock,[135] the RDEIR must analyze the range of potential impacts from this shift, in relation to both the Santa Maria and Rodeo facilities, as they together comprise the San Francisco Refinery. This failure to adequately analyze increased TAC and HAP emissions that stem from the physical and chemical composition of the crude imported to the SMR by way of the Project, and processed at the SFR, results in a critical omission of significant, public health impacts, and violates CEQA.[136]

(iv) The DEIR Does Not Analyze Emissions from All of the Project's Components.

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132 *Id*.
133 *See* CBE Comment to DEIR.
134 *See*, *Laurel Heights Improvement Assn. v. Regents of Univ. of California, supra,* 47 Cal.3d, at 400 (*quoting* Pub. Resources Code § 21002.1(a); and Guidelines 15002(a)).
135 *See* Fox Comments.
136 *See*, *County of Inyo v. City of Los Angeles*, (1977) 71 Cal. App. 3d 185.

The RDEIR fails to analyze all of the Project's components in two respects. First, the RDEIR shirks the lead agency's responsibility to mitigate emissions due to unpersuasive assertions of federal preemption of regulating locomotives. Second, the RDEIR's analysis is limited to those locomotives.

First, the RDEIR improperly dismisses mitigation measures on account of unpersuasive assertions of federal preemption. Specifically, a lead agency should not shirk responsibility to identify adequate mitigation measures on the sole basis of such an assertion. Rather, lead agencies must identify suitable mitigation measures, and not end an analysis because of a legal roadblock to but one of a menu of options for mitigation.

Second, the RDEIR still fails to assess emissions from all integral components of the Project. The RDEIR identifies operational emissions from "the operation of locomotives (both onsite and offsite), fugitive emissions from components and from the vapor recovery carbon canisters, and from vehicles associated with employees and the transportation of materials."[137] Most blatantly, this fails to assess the air quality impacts of the SFR as a whole, and includes neither an analysis of the emissions that will be caused at the Rodeo component as a result of the rail spur extension, nor the increased emissions of refining increased quantities of tar sands at the Santa Maria component.

CEQA requires that an EIR consider the impacts of a whole project, not simply its constituent parts, when discussing the environmental effects of the project.[138] As discussed *supra* in Part II, an essential element of this Project is a shift to a different-quality crude slate, and the Santa Maria Throughput Expansion, Rodeo Propane Recovery Project and this Project are at least three integral components of this piecemealed project. Consequently, this DEIR should include an analysis of the full scope of air quality impacts resulting from this larger piecemealed project, not just the impacts from the Rail Spur Extension Project.

In addition, because the DEIR does not disclose the scope of tar sands that will be brought to the SFR as a result of the rail spur expansion, the RDEIR cannot analyze the severe air quality impacts that will result from processing those increased quantities first at the Santa Maria facility, and subsequently the Rodeo facility. The refining of this different quality crude slate can be reasonably expected to require an increase in frequency and magnitude of flaring at Santa Maria, since dirtier crude processing would likely increase "malfunction" and "emergency" flaring.[139] Moreover, a malfunction or emergency upset causes the whole contents of one or more major process vessels to depressurize suddenly, and each flaring event can cause acute exposures to emitted pollutants.[140] Each of these flaring episodes comes with associated and extremely high levels of additional pollution that the RDEIR's analysis ignores.

In addition, the daily operation and refining of a different quality crude slate will result in increased daily emissions of pollutants, including many toxic/PM precursor/smog-forming air

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[137] RDEIR at 4.3-32.
[138] *See* CEQA Guidelines, 14 Cal. Code Reg. § 15003(h); *Citizens Assoc. for Sensible Degvelopment of Bishop Area v. County of Inyo* (1985) 172 Cal.App.3d 151.
[139] *See* Karras Rodeo Report.
[140] *Id.*

pollutants from burning more fuel per barrel to process the likely denser/dirtier crude feeds.[141] An increase in fugitive emissions and heightened concentrations of toxic VOCs can also be anticipated as a result of the higher pressure processing of denser crudes.[142] The RDEIR does not analyze these effects, either at the Santa Maria or Rodeo ends of the SFR, and consequently, also fails to discuss mitigation measures for these impacts.

The environmental review of this Project presents a critical opportunity to engage in a genuine and thorough review of the full environmental impacts of this Project. By failing to analyze the emissions from all components of the larger project, the DEIR obfuscates the full extent of air quality impacts, and renders informed decision-making on this Project impossible.

(v) The RDEIR Fails to Adequately Analyze the Significant Climate Change Implications of this Project.

The RDEIR wholly underestimates the significant, and irreversible, effect that the project presents to climate change. Although the RDEIR makes references to the Intergovernmental Panel on Climate Change, it's references are outdated, and in fact contradicted by more updated reports. Specifically, the RDEIR fails to acknowledge the Intergovernmental Panel on Climate Change's recently voiced and serious concerns regarding the "irreversible" effects of climate change.[143] The report concluded that "continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts," calling for the need for dramatic cuts in pollution.[144]

In the face of that warning, the Project admits a climate change impact that is significant and unavoidable.[145] However, no intelligent weighing of whether to live with that impact is possible without first establishing the degree of that significant impact. The RDEIR underestimates even this significant impact. Not only does its analysis restrict the scope of impacts to generally locomotive and ancillary emissions, ignoring the climate change impacts of this larger tar sands project, but even that analysis is plagued with ambiguity and a failure to analyze alternative mitigation measures.

(a) The RDEIR Fails to Analyze All GHG Emissions from All Components of the Project.

As noted throughout this comment, the Project is piecemealed. In regards to climate change impacts, the RDEIR must disclose all of the SFR's GHG emissions that the Project will enable not only at the Santa Maria facility, but also at the Rodeo end of the facility. Moreover, as acknowledged by the RDEIR, the climate change impacts of refining are correlated to the

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141 *Id.*
142 *Id.*
143 *See eg.* "Effects of Climate Change "Irreversible"' available at http://www.washingtonpost.com/national/health-science/effects-of-climate-change-irreversible-un-panel-warns-in-report/2014/11/01/2d49aeec-6142-11e4-8b9e-2ccdac31a031_story.html?hpid=z1
144 Report attached as Attachment D.
145 RDEIR at 4.3-71.

quality of the feedstock refined.[146] Refining tar sands at the SFR, compared to refining the more traditional blend, creates far greater GHG emissions and therefore climate change implications. Until the RDEIR corrects its Project Description regarding the degree of shift to refining tar sands at the SFR, its analysis cannot provide any adequate analysis of the Project's, already determined as significant, impacts to climate change.

In addition, CEQA requires an EIR to consider both direct and indirect impacts of a proposed project.[147] Indirect impacts are those that are "caused by the project and are later in time or farther removed in distance, but are still reasonably foreseeable."[148] The scale of the Project's activities is large enough that off-site emissions could reasonably be affected. Moreover, the indirect nature of these wholly foreseeable off-site emissions cannot be ignored as "it is inaccurate and misleading to divide the project's air emissions analysis into on-site and secondary emissions for purposes of invoking the presumption the project will have no significant impact."[149] Thus, the RDEIR requires a sufficient analysis and discussion of these sources. For example, in *North Coast Alliance*, the lead agency's analysis of the identification of indirect sources of GHG emissions from electrical demand was found sufficient given that the agency conducted a thorough analysis of the project's demand on a utility's electricity generation and whether it would increase production at any fossil-fuel power plants.[150]

Similarly here, an inextricable link exists between the Santa Maria and Rodeo ends of the SFR. Just as it was foreseeable in *North Coast Alliance* that utility demand would be met, it is just as foreseeable, if not a certainty, that the Rodeo facility will exactly meet the demand of the Santa Maria facility's export by the pipeline, owned by Phillips 66, that connects the two facilities. The RDEIR fails to acknowledge the full scope of GHG emissions from the Project. By limiting the study of GHG emissions to largely locomotive and associated operations alone, but one component of the overall Project, the RDEIR omits entirely a significant portion of the emissions that will result from the Project, and thus vastly underestimates the Project's significant air quality impacts.

Emissions from the Rodeo facility include increased GHG emissions resulting from the processing of tar sands, as well as the off-site emissions from the propane and butane produced via the Propane Recovery Project and the off-site emissions associated with natural gas demand activities. The RDEIR must, at the least, identify these foreseeable activities and then adequately analyze and estimate how much the Project is likely to increase emissions from all of these sources, regardless of their location. At a minimum, the RDEIR must address these emissions as reasonably foreseeable cumulative impacts, as more fully addressed below.

(b) The RDEIR's Proposed Mitigation of Project GHG Emissions is Inadequate.

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[146] RDEIR at 4.3-70.
[147] CEQA Guidelines, 14 Cal. Code Reg. § 15358(a).
[148] CEQA Guidelines, 14 Cal. Code Reg. § 15358(a)(2).
[149] Kings County Farm Bureau v. City of Hanford (1990) 221 Cal. App. 3d 692, 717.
[150] North Coast Alliance v. Marin Mun. Water Dist. Bd. of Directors, 216 Cal.App.4th 614, 652 ("Based on this evidence, the EIR concluded the Project's energy demand would not result in an indirect increase in pollutant emissions.").

The RDEIR's proposal to mitigate all of the Project's increased GHG emissions is too vague, speculative, and a potentially illegal use of Emission Reduction Credits ("ERC's"). This is how the RDEIR proposes to mitigate the Project's potentially massive increase in GHG emissions:

> Mitigation Measure AQ-6: Prior to issuance of the Notice to Proceed, the Applicant shall provide GHG emission reduction credits for all of the project GHG emissions for the life of the project. Coordination with the San Luis Obispo Planning and Building Department should begin at least six (6) months prior to issuance of operational permits for the Project to allow time for refining calculations and for the San Luis Obispo Planning and Building to review and approve the emission reduction credits.

An ERC is a credit granted to a facility that voluntarily reduces emission beyond a certain required level of control; it then provides the authority to emit the regulated pollutant in an amount equal to that original reduction. One principle issue with ERCs is that these emission reductions may have been realized elsewhere from the project location. There may be no real emission reduction in the actual project area. Therefore, the cumulative impact of any emissions increases, addressed by such credit related mitigation measures, remains and goes wholly unanalyzed, along with the emission of any associated, and potentially also separately significant co-pollutants. This oversight of impacts to the most vulnerable sections of our population pervades the RDEIR. In addition, the RDEIR's proposed use of these ERCs is wholly vague. Its analysis hopes to avoid the use of additional ERC's to mitigate GHG emissions from locomotive operations, yet is unable to come to a conclusion of whether and how much would be necessary in order to do so.

In addition, the RDEIR lacks any attempt to quantify the amount of GHG reductions that could be achieved by ERCs. Is it as simple as a 1:1 ratio/offset? The SLOCAPCD recommends using the CAlEEMod for mobile sources and a partial characterizariton of area source impacts. In cerain cases, it will also suggest alternative methods.[151] What method applies in this case? Regardless, the RDEIR must provide sufficient detail for the decision making body to at least determine whether an exclusively ERC method of mitigation is even feasible.

Also, as more fully detailed below, in 2007, Phillips 66 entered into a settlement agreement with the Attorney General to resolve a conflict over the GHG emissions that would result from a proposed Clean Fuels Expansion Project at the Rodeo Refinery. In this Agreement, Phillips 66 agreed that the ERCs issued by SLOCAPCD for the shutdown of one of its sources cannot be sold or transferred, and could only be used for modifications or expansions at the Santa Maria Refinery.[152] If those ERCs are used at the Santa Maria Refinery, Phillips 66 committed to "offset all GHG emissions that result from the use of the ERCs,"[153] either by GHG reductions at other Phillips 66 refineries or by permanently retiring AB 32 GHG credits. The additional requirements that the use of the ERCs—namely, complete offsetting of GHG emissions resulting from the use of the ERCs—are highly relevant to the air quality analysis in

[151] SLOCAPCD CEQA Handbook, 2012, at 3-14.
[152] Attachment F, Amendment to Settlement Agreement Between ConocoPhillips Company and the Attorney General of California, May 25, 2010..
[153] Attachment F, para. 4.

this RDEIR, and the analysis is incomplete and potentially misleading without including any discussion of this Settlement Agreement. The RDEIR must be revised to provide some adequate quantification of the feasibility of the use of ERCs to mitigate the GHG impacts of this Project. Otherwise, certification of this document would create additional administrative confusion and burden. Although the Attorney General has the authority to enforce those provisions at a later date, the RDEIR must disclose that and at least analyze a scenario of non-compliance, which it fails to do.

Furthermore, the RDEIR's focus and dependence on an overbroad and vague use of ERCs seems wholly misplaced when compared to the GHG mitigation measures proposed by the SLOCAPCD. Certainly, the RDEIR avails itself to the jurisdiction and certain thresholds estabilished by the SLOCAPCD. Despite that, however, the RDEIR chooses to ignore the SLOCAPCD's recommendations on GHG mitigation measures, instead opting for a more unstable option of pursuing ERCs. The SLOCAPCD recommendations include mitigation measures targeting energy efficiency.[154] In particular, the SLOCAPCD recommends onsite renewable energy systems and other community based, more local, solutions.[155] These mitigation measures are not only recommended, but feasible, will create more jobs, and are not plagued by the same environmental justice concerns as the mitigation proposed by the RDEIR. Any environmental review of this proposed Project must address these alternative forms of mitigation that prove more beneficial to the communities immediately and disproportionately already affected by the SFR.

(vi) The DEIR Inappropriately Relies on Emission Reduction Credits to Mitigate the Project's Significant Air Quality Impacts.

The Proposed Project will result in significant increases in emissions of criteria air pollutants (CAPs). The RDEIR proposes to mitigate these impacts by securing ERCs to offset any emissions over the applicable significance thresholds, in order to ensure that emissions "do not exceed the Air District thresholds for the life of the project."[156] The RDEIR proposes to acquire ERCs for ROG + NOx and DPM, both within San Luis Obispo County and outside of the county along the UPR mainline.[157] The RDEIR also intends to reduce toxic emissions below applicable threshold via ERCs.[158] Finally, the RDEIR proposes to mitigate GHG emissions below SLOCAPCD thresholds with GHG ERCs. Mitigation Measure AQ-6 provides that "the Applicant shall provide GHG emission reduction credits for *all* of the project GHG emissions for the life of the project."[159]

(a) The RDEIR Provides Insufficient Information On Its ERC Mitigation Measure.

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154 SLOCAPCD CEQA Handbook, 2012, at 3-17 to 3-20, Table 3-5.
155 *Id.*
156 RDEIR at 4.3-53.
157 RDEIR at 4.3-47 (Mitigation Measure AQ-2a), -53 (Mitigation Measure AQ-3).
158 RDEIR at 4.3-63 (Mitigation Measure AQ-4), -67 (Mitigation Measure AQ-5).
159 RDEIR at 4.3-71 (emphasis added).

For ROG + NOx, DPM, and GHGs, the RDEIR's mitigation measures provide that Phillips 66 will be required to secure or provide emissions reduction credits sufficient to bring the Project's emissions below the applicable significant thresholds. However, this is all of the information that the RDEIR provides about the ERCs. The RDEIR does not provide any further information about what ERCs the facility already possess, the quantity of ERCs that may be required, or where ERCs might be acquired from.

The RDEIR does not provide any further information about the quantity of ERCs that might be required to fully mitigate each pollutant, the quantity of ERCs that Phillips 66 already has in the SLOCAPCD bank, or whether Phillips 66 would have to purchase banked ERCs from another certificate holder. The RDEIR does not discuss the offset ratio, in order to determine the number ERCs that would be required to offset each ton of CAP emissions. The RDEIR does not identify the specific ERCs that it plans to use, which makes it impossible to determine whether the ERCs have limitations on use.

Importantly, the RDEIR does not make any mention of the existing settlement agreement between Phillips 66 and the California Attorney General that limits the Refinery's use of ERCs. In 2007, Phillips 66 (then ConocoPhillips) entered into a settlement agreement with the Attorney General to resolve a conflict over the GHG emissions that would result from a proposed Clean Fuels Expansion Project at the Rodeo Refinery. In this Agreement, Phillips 66 committed to permanently surrender the operating permit for the calcining plant at the Santa Maria Refinery, in order to reduce Phillips 66's GHG emissions in California.[160] In a 2010 Amendment to the Agreement, Phillips 66 agreed that the ERCs issued by SLOCAPCD for the shutdown of the calclining plant (ERC Certificate No. 1318-Z1) cannot be sold or transferred, and could only be used for modifications or expansions at the Santa Maria Refinery.[161] If those ERCs are used at the Santa Maria Refinery, Phillips 66 committed to "offset all GHG emissions that result from the use of the ERCs,"[162] either by GHG reductions at other Phillips 66 refineries or by permanently retiring AB 32 GHG credits. Phillips 66 is also required by the terms of the Settlement Agreement to notify the Attorney General "when it submits an application for a project at the Santa Maria Refinery that *may* use all or a portion of the ERCs."[163] The RDEIR does not specify whether these credits will be used in this Project, nor does it specify whether the Attorney General has been notified of the potential use of these credits. The additional requirements that the use of the ERCs on Certificate No. 1318-A1 would trigger—namely, complete offsetting of GHG emissions resulting from the use of the ERCs—are highly relevant to the air quality analysis in this RDEIR, and the analysis is incomplete and potentially misleading without including any discussion of this Settlement Agreement.

Furthermore, the RDEIR makes no commitment to or mention of the permanent retirement of ERCs, and instead proposes to "acquire" or "provide" offsets. Without a commitment to the permanent retirement of ERCs, the mitigation achieved by ERCs would be illusory. The Refinery could simply hold on to the ERCs, and later sell or transfer them, thus allowing emissions levels to increase above this Project's baseline. Phillips 66 must commit to

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160 Attachment F, Exhibit A, para. 1.a.
161 Attachment F.
162 *Id.* at para. 4.
163 *Id.* at para. 7 (emphasis added).

permanently retiring any ERCs that it uses for mitigation in order to ensure that actual, on-the-ground emissions are reduced.

(b) Using Credits to Mitigate CAP Emissions Would In Fact Increase Emissions in San Luis Obispo County and Along the UPR Main Line.

ERC retirement fails to actually mitigate emissions. ERCs represent emission reductions that were made in the past. Thus, the retirement of an ERC today has no impact on actual emissions today. Instead, the retirement of an ERC represents the prevention of a future emissions increase, and a region-wide, "on paper" decrease in allowable emissions levels.

However, CEQA is not concerned with impacts "on paper," but instead with actual, on-the-ground impacts on human health and environmental quality.[164] While ERC retirement may reduce future allowable levels of pollution, thus complying in theory with CEQA's mandate that emissions be reduced below applicable significance thresholds, employing ERC retirement as mitigation for this Proposed Project will result in an increase in emissions in San Luis Obispo County and along the UPR main line above existing levels. This measure would not mitigate the Proposed Project's impacts, but would instead permit the impacts to occur unmitigated. The City should not approve a mitigation measure that would increase CAP, TAC/HAP, and GHG emissions above current levels, and should instead rely on mitigation measures that would result in actual emissions reductions in San Luis Obispo County and along the rail tracks leading to the Refinery.

B. The RDEIR Fails to Adequately Disclose, Analyze, and Mitigate Project-Related Hazards and Public Safety Risks.

An EIR must provide sufficient information to evaluate all potentially significant impacts of a project, including public safety risks due to accidents, and it must state sufficient information to determine "how adverse [an] adverse impact will be."[165] This information is critical to the public and agency decision makers as they evaluate the extent and severity of the Project's impacts, specifically as they relate public safety.

The RDEIR fails to meet this CEQA requirement in three respects: (1) while it mentions an overall change in crude slate as part of the Project, it fails to adequately analyze the implications of that shift as it concerns a realistic and genuine assessment of resultant safety impacts, including those that may stem from routine transport and handling, train car derailments and other accidents, and refining; (2) it applies flawed, underestimated assumptions regarding the increased risks of crude oil spills and resulting impacts, caused by the Project; and (3) it illegally defers mitigation by relying on safety precautions and anticipated plans that will not be implemented within a reasonable time.

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[164] *See, e.g.*, CEQA Guidelines § 15358(b) (limiting CEQA analysis to impacts "related to a *physical* change") (emphasis added); CEQA Guidelines § 15002(g) (defining "significant effect on the environment as a substantial adverse change in the physical conditions which exist in the area affected by the proposed project"); CEQA Guidelines § 15126.4(a) (identifying mitigation measures as those which could minimize significant effects on the environment).

[165] *Santiago County Water District v. County of Orange* (1981) 118 Cal. App. 818, 831.

(i) The RDEIR Does Not Adequately Consider the Specific Impacts of Transporting Tar Sands Crude by Rail.

Numerous accidents including fires, explosions, and spills have resulted from a rapid increase in crude transport across North America. Such incidents have been caused by accidents such as derailments, as well as non-accident releases from leaking valves or vents.[166]

The RDEIR acknowledges that the main hazards associated with the Project include potential fires and explosions that could occur as result of a spill or accident at the SMR, or along the UPRR mainline tracks.[167]

The RDEIR further acknowledges that the Project is one that will necessarily increase the transport and processing of distinctly dense and toxic diluted bitumen-based Canadian crude blends, which are disclosed in the document as "Access Western" and "Peace River Heavy" blends.[168] These crudes and the diluents with which they must be blended to enable their transport and processing pose particularly serious environmental and public health threats when accidentally released into the environment.[169]

In response to the spike in train car derailments and other accidents causing crude spills, the U.S. EPA recently noted that spills of diluted bitumen require different response action and equipment than conventional oil spills.[170] Indeed, three years after a major spill of DilBit into the Kalamazoo River in Michigan, heavy oil remains at the bottom of the river. Resource intensive cleanup is required to remedy the damage caused by the Kalamazoo oil spill, amounting to $1 billion in costs to public funds.[171]

Tar sands bitumen crudes and diluted blends not only pose unique problems regarding cleanup in the event of spills and other accidents, but they also pose serious concerns regarding equipment safety. Government agencies including the Federal Railroad Administration have expressed concern about an increasing number of severe corrosion incidents found in rail tank cars and service equipment.[172] Incidents of derailments and explosions of hazardous materials along California rail routes specifically have also been known to cause extensive environmental

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[166] Mike Soraghan, *Crude Mishaps on Trains Spike As Rail Carries More Oil*, E&E (July 17, 2013), *available at* http://www.eenews.net/stories/1059984505

[167] RDEIR at ES-11; 4.7-42.

[168] RDEIR at 2-33.

[169] Mike Soraghan, *Crude Mishaps on Trains Spike As Rail Carries More Oil*, E&E (July 17, 2013), *available at* http://www.eenews.net/stories/1059984505

[170] EPA, *Comment Letter to US Department of State Regarding the Supplemental Draft Environmental Impact Statement from TransCanada's Proposed Keystone XL project* (2013), *available at* http://www.epa.gov/Compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf.

[171] EPA, *Comment Letter to US Department of State Regarding the Supplemental Draft Environmental Impact Statement from TransCanada's Proposed Keystone XL project* (2013), *available at* http://www.epa.gov/Compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf.

[172] See http://www.fra.dot.gov/eLib/details/L04717.

damage in the past,[173] and recently, persistent and continued accidents involving crude transport by rail have garnered a significant amount of media attention.[174]

Yet, despite the unique characteristics of bitumen crudes and DilBit blends, including those characteristics which cause dramatic increases in corrosion in all refinery equipment components, the RDEIR avoids full analysis of the unique hazards accompanying rail transport, offloading, handling, storage, and processing of these crudes in its review of the Project's potential impacts.[175] As a result, the RDEIR's conclusions regarding the relative significance of the Project's impacts and its assessment of mitigation measures to address the same are inherently flawed.

a. The RDEIR Fails to Consider the Specific Hazard Risks Associated with the Transport of Tar Sands.

The RDEIR fails to consider the shift in crude slate when assessing the relative significance of the range of potential impacts caused by a crude oil spill. Rather than analyzing the simultaneous impacts from increased incidents of train car derailments and other accidental releases, and the corrosive effects of tar sand and DilBit blends as well as their unique challenges in cleanup, the RDEIR applies a quantitative estimation of train car accidents and derailments overall, and only mentions the potential risks associated with the Project's crude slate shift separately.

The RDEIR acknowledges throughout its analyses that implementation of the project "could result in spills at the Project Site due to mechanical failure, structural failure, corrosion, or human error during pipeline use and oil transportation to and from the rail spur." [176] Yet, it concludes that "given the low speed the trains would be moving at the site (3 mph) it is unlikely that a tank car could be impacted enough to result in a spill" and that "the most likely spill related event would [therefore] be a release during the unloading process due to a loading line failure." [177]

The segmentation of the categories of risk associated with potential train car derailments from the known significant risks caused by corrosive properties of tar sands and DilBit crudes, therefore, allows the RDEIR to conclude—erroneously and in contradiction of substantial evidence—that the hazards impacts are less than significant, and do not require mitigation. Because this conclusion and the methodology used to reach the conclusion are both inherently flawed, the RDEIR must be revised and re-circulated to address the errors in its significance findings for the Project's potential on-site hazards impacts.

[173] For example, there was a very major spill into Upper Sacramento River in 1991. *See*, http://www.dfg.ca.gov/ospr/NRDA/Cantara.aspx.
[174] *See*, *e.g.*, *Accidents Surge as Oil Industry Takes the Train,* New York Times, Jan. 25 2014, available at http://www.nytimes.com/2014/01/26/business/energy-environment/accidents-surge-as-oil-industry-takes-the-train.html?hp&_r=1.
[175] *See supra* Part II.A.
[176] See e.g., RDEIR at 4.7-42
[177] See e.g., *id.* at 4.7-42

The RDEIR further ignores the fact that the change in crude slate enabled by the Project involves serious potential emissions of high level VOCs and hazardous air pollutants (HAPs) implicating severe public health impacts. As explained in detail in the comments submitted to the DEIR, diluents are comprised of low molecular weight organic material with a high vapor pressure, and contain high levels of VOCs, sulfur compounds, and HAPs.[178] These would be emitted during unloading, and would be contained in emissions from the crude tank(s) as well as fugitive components used to facilitate crude movement from transport and storage units, and into refining and process units, including those at the Rodeo facility.[179] The presence of diluent would increase the vapor pressure of the crude, substantially increasing VOC and HAP emissions from tanks and fugitive component leaks—all of which are not addressed the RDEIR.[180]

Moreover, these emissions would be highly prominent in any accidental releases caused by fire, explosion or other forms of accident, exacerbating the impacts of these incidents when they occur. Because the RDEIR fails to acknowledge, much less analyze or attempt to mitigate the potential impact from these emissions, it fails to comply with CEQA and must be revised and recirculated.

(ii) The RDEIR Fails to Discuss the Public Safety Risks of Refining a Different or Lower Quality Crude Oil Feedstock.

As noted above, a switch to a heavier oil feedstock necessarily implicates a greater risk of corrosion of refinery components.[181] This greater risk of corrosion was identified as a root cause of the August 2012 fire at the Chevron Richmond Refinery that sent 15,000 residents to local hospitals.[182] The RDEIR states explicitly that the Project will involve transporting heavy, higher sulfur-content crude, including tar sands crudes, yet it fails to adequately discuss the significant impacts resulting from this shift to a lower quality oil feedstock. As a result, the document precludes any meaningful analysis of the significant risks posed by this shift, including any identification or mitigation of the potential risks of catastrophic failure on par with what occurred at the Chevron Richmond Refinery in 2012 and any additional significant impacts to public health.

Tar sands blended crudes can lead to significant increases of all criteria pollutant emissions, as well as TAC and HAP emissions as a result of the increase in energy, and energy intensity required for processing and refining, and the increased risks associated with corrosion and potential accidents.[183]

As discussed above, while the RDEIR makes mention of potential increases in "emissions of toxic materials from fugitive emissions sources," caused by the Project, it fails to adequately

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[178] *See* Attachment A, Fox Comment.
[179] See *id.*
[180] *See i.d.*
[181] *See supra* Part II.A; Fox Comments on Mitigated Negative Declaration of Valero Crude By Rail Project, Use Permit Application 12PLN-00063.
[182] *See* Chemical Safety Board, Chevron Richmond Refinery Interim Investigation Report, April 2013, available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf.
[183] *See* Fox Comments ("more energy will be required and more emissions produced to convert them into the same slate of semi-refined and refined products").

identify, analyze, and mitigate the full range of impacts caused by refining a significantly larger quantity of tar sands crudes at the SMR. The RDEIR improperly limits its analysis of the public health risks to the cancer risks analyzed in the HRA, and omits the public health hazards that would result from potential accidents, fires and other accidental releases caused by day-to-day project operations. Because the non-cancer risks are concerning and are potentially severe and the high sulfur and acid levels contained in these crudes and their semi-refined products dangerously accelerate corrosion of refinery components, contributing to equipment failure and causing more frequent accidental releases, these risks cannot remain undisclosed, without proper mitigation.

Moreover, because refining activities at the SMR are inherently linked to those which occur at the Rodeo facility and the Project has been improperly piecemealed from other related project, the RDEIR must account for increased emissions from refining tar sands crudes throughout the San Francisco Refinery.

Because the RDEIR fails to adequately analyze these impacts and state adequate mitigation to address them, it fails as an informational document and must be recirculated.

(iii) The RDEIR's Mitigation of Hazards is Inadequate.

The October 1, 2011 Department of Transportation (DOT) standards (also known as the "CPC-1232" standards) do not sufficiently minimize the risk of a hazardous material release involving Tar Sands crude:

> NTSB has long found that other features of DOT-111 tank cars, such as the bottom outlet valves, are inadequate and susceptible to breaches and has indicated that it is not convinced that the CPC-1232 modifications offer significant enough safety improvements. For its part, [Association of American Railroads] supports making additional modifications beyond the CPC-1232 standards by requiring that all tank cars carrying crude and ethanol have jackets, full-head shields, thermal protection and bottom outlet valve safeguards. BNSF officials have indicated that they would not have supported the consensus CPC-1232 standard in 2011 if they had known about crude oil at the time. They now believe the tank cars need to have a jacket and thermal protection in addition to the CPC-1232 upgrades, and have represented that these additional safeguards would increase tank car crashworthiness by another 50% over that afforded by the CPC-1232 standards.[184]

The RDEIR also relies on voluntary measures as assurance that derailments and accidents will be minimized, but there are no assurances of actual adherence to these measures. Moreover,

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[184] *See* Earthjustice Petition to the Secretary of Transportation to Issue an Emergency Order Prohibiting the Shipment of Bakken Crude Oil in Unsafe Tank Cars (July 15, 2014), p. 16, *available at* http://earthjustice.org/sites/default/files/files/PetitionforEmergencyOrderReBakkenCrudeRailCars.pdf; *see also* "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Fed. Reg. 45,016 (Aug. 1, 2014) [noting safer specifications for tank cars].

nothing in the RDEIR indicates whether any of these measures actually apply to the railroads servicing the Project.

The RDEIR must perform a proper study of the risks of transporting tar sands crudes in particular, and it must require actual, specific, and enforceable measures to mitigate those risks.

(iv) The RDEIR's Analysis Illegally Defers Mitigation of Public Safety Precautions.

Formulation of mitigation measures should not be deferred until some future time.[185] Numerous cases illustrate that reliance on tentative plans for future mitigation after completion of the CEQA process significantly undermines CEQA's goals of full disclosure and informed decisionmaking.[186]

The RDEIR here relies on the hope, or anticipation, that both federal and state agencies will implement stronger standards for tank car safety regulations and other safety precautions to ensure a lower accident risk, and emergency plans to minimize damage when accidents do occur. While the RDEIR goes so far as to cite to some of these new, developing efforts, including those being developed by the Pipeline and Materials Safety Administration (PHMSA), the DOT, and the American Association of Railroads (AAR), it fails to assure the public and agency decisionmakers that such efforts will lead to any legally enforceable standards, applicable to the Project.[187] Moreover, in the event that such efforts do in fact materialize into legally enforceable requirements and/or standards, they are not legally enforceable at this time. Thus, to the extent the RDEIR sets forth such efforts in the context of its required mitigation measures, they constitute deferred mitigation and as such, are prohibited under state law.[188]

Though the RDEIR identifies four mitigation measures for the significant increase in risk of crude oil train derailment associated with the Project, all of these mitigation measures are qualified with a statement that "[t]he County may be preempted by federal law from implementing these measures."[189] The RDEIR then makes a general reference to the Interstate Commerce Commission Termination Act (ICCTA), but fails to undertake any analysis of ICCTA as it applies to the specific mitigation measures proposed by the RDEIR. By failing to analyze the preemption question with any degree of particularity, and instead relying on broad assumptions of preemption, the RDEIR illegally defers mitigation of the significant risks to public safety.[190] These impacts must be fully mitigated before any project approvals, and the Final EIR must include revisions to address these impacts.

Moreover, the RDEIR's analysis of the risk of train derailment is misleading because it is conducted entirely within the context of the DOT's proposed crude by rail safety regulations

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185 CEQA Guidelines § 15126.4(a)(1)(b).
186 *See eg. Cmtys. for a Better Env't v. City of Richmond*, 184 Cal.App.4th at 92.
187 *See* RDEIR at 4.7-21 to -24.
188 *See* RDEIR at 4.7-62 to -63 (Mitigation Measures HM-2a through -2d).
189 RDEIR at 4.7-63.
190 See also *supra* Part III.A.iv.a ("The DEIR Erroneously Purports that Mitigation is Preempted, Thereby Avoiding Critical Measures to Abate the Hazards and Impacts of Increased Crude by Rail Transport through California Communities").

which are not yet finalized and which present various options for new tank car design that offer varied degrees of improved safety.[191] Importantly, the rule is not yet finalized, and implementation of it will likely not occur for several years after the proposed project begins operation. Further, if the proposed project, as it states, largely imports heavy crude such as tar sands, the proposed federal DOT rule provides the SMR Project with little if any accident risk reduction benefits. That is because the proposed DOT rule assumes that the aging fleet of DOT111 tank cars will largely be shifted to tar sands service. As such, the proposed Project will not benefit from the safety improvements of the proposed rule's new tank car designs. Further, the federal DOT proposed rule estimates that 15 mainline crude rail accidents will occur each year and at least one catastrophic incident at least as large as Lac Megantic will occur at least every two years under the existing rail infrastructure network. Given that the proposed federal rules will not be finalized and implemented for several years, and that the proposed Project likely will not see many of the safety improvements required by the rule, the RDEIR must evaluate the risk of accidents and spills based on the hazards associated with existing rail infrastructure.

(v) The RDEIR's Analysis of Risk of Oil Spill and Train Derailment is Inaccurate and Misleading.

In its analysis of potential risks of hazards, accidents, and spills of over 100 gallons of oil, the RDEIR makes reference to incidents like the Lac Megantic disaster in July 2013, and a handful of others. Despite listing three additional accidents occurring since the Lac Megantic incident occurred less than sixteen months ago, the RDEIR erroneously concludes that there is a low probability that any accident, incident, or occurrence causing any damage or significant impact will occur. Moreover, the RDEIR finds that only those incidents causing 100 gallons or more of crude to spill merit consideration in the hazards analysis for the Project, because spills under 100 gallons are less likely to extend beyond the railroad right of way and less likely to produce explosions.[192] No further support is given to justify the 100 gallon cut-off, beyond these broad statements that more serious accidents are "unlikely" below 100 gallons.

The RDEIR's Quantitative Risk Assessments estimates that spills or other accidents resulting in the release of over 100 gallons of crude oil are likely to occur between once every 46 years and once every 76 years, depending upon the rail route.[193] However, this estimate relies on historical derailment data from 2003-2012, and does not include any of the catastrophic derailments from 2013 and 2014. As such, the probability of catastrophic events is artificially low, and the risk assessment must be re-analyzed in order to include more recent and representative data on derailments.

(vi) The RDEIR's Accident and Spill Risk Analysis is Flawed in Omitting Critical Data Reflecting Recent Increases in Crude by Rail Accidents and Releases.

The RDEIR's analysis of accident risk and magnitude of spills is flawed. First, the analysis in section 4.7 and Appendix H.2 only evaluates rail accident rates from 2003 to 2012

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[191] RDEIR at Appendix H.2, 10-12.
[192] *See* RDEIR at 4.7-47.
[193] *Id*.

and touts that accident rates are declining.[194] However, those conclusions are misleading because they omit very relevant data. Accident rates in 2013 and 2014 specifically for crude by rail actually increased. In order to fully understand the risks of accidents for the proposed SMR crude by rail project the RDEIR must include this more accurate and up to date data in its analysis. The RDEIR should also look at similar data from Canada to obtain a more accurate assessment of crude accidents using existing rail infrastructure.

The RDEIR also evaluates spill release rates of all hazardous materials between 2005 and 2009.[195] This data is entirely unrepresentative of the current state of play for rail-based crude releases because it looks at all hazardous material spills and not crude specifically. It also omits recent data which is critical to analyzing the magnitude of potential spills. In 2013 alone more crude spilled from trains than spilled in the last four decades combined. The RDEIR cannot simply omit this data. Also, as stated in the U.S. Department of Transportation's proposed crude by rail safety rulemaking, the industry regularly underreports accident spill quantities. Thus, the RDEIR's conclusion that its analysis of accident and spill risk is "conservative" because, among other reasons, the railroad industry's overall accident rate is declining, completely misses the mark.[196] In fact, quite the opposite is true. If the RDEIR had included recent data specific to crude by rail accidents and spills, the results would likely show that the risk of an accident and spill quantities are much higher.

(viii) The RDEIR's Worst Case Scenario Spill Analysis is Flawed.

Finally, the RDEIR's worst case scenario spill analysis is also flawed. The RDEIR estimates a worst case spill of approximately 180,000 gallons, the capacity of approximately six tank cars.[197] This must be and error because we know that most crude trains are comprised of 80 to 100 or more tank cars each carrying approximately 30,000 gallons of crude. As such, a *worst case* scenario spill should evaluate the possibility of a spill that releases an entire unit train's crude capacity – an analysis on the order of at least 2.5 million gallons. The analysis of a worst case disaster should evaluate how such a spill would affect sensitive and critical ecosystems such as the San Francisco Bay watershed, drinking water sources for California residents, agricultural resources as well as urban downtowns. The worst case spill analysis also must look at the impacts of massive spills of different types of crudes that may be transported by the proposed project, including difficult to remediate tar sands crudes and highly volatile Bakken crudes. Indeed, this project cannot be approved without analyzing and mitigating its true impacts, including the true impacts of a worst-case disaster.

C. The DEIR Fails to Adequately Analyze the Project's Impacts on Local Agriculture and Water Quality and Supply.

(i) The RDEIR Underestimates Impacts to Agriculture.

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[194] RDEIR at 4.7-4-13.
[195] RDEIR at Appendix H.2, 12.
[196] *Id*.
[197] RDEIR at 4.2-38; 4.7-47.

The Project would result in significant impacts to agriculture. As detailed immediately below, the RDEIR overlooks several of these impacts. It nevertheless does conclude that there will be a significant and unavoidable impact in the event of derailment along the mainline.[198] However, even that significance is again underestimated.

(a) Inadequate Analysis of Impact to Agriculture.

The RDEIR mistakenly concludes that, with mitigation, there will be no significant impacts to agricultural uses due to the Project's increased water usage, generation of dust, weeds, and increased risk of fire or oil spills.[199] Two principle errors of the RDEIR pervade this analysis: first, the RDEIR's failure to adequately assess the full scope of this Project and the impact of refining and transporting tar sands; and second, the RDEIR's inadequate mitigation responses due to unpersuasive assertions of federal preemption. The RDEIR's analysis, limited in scope, evidently limits the assessed impacts. As illustrated throughout this comment, the local impact of refining tar sands has a very different and significant local impact than assessed in the RDEIR. Furthermore, the artificially low bar set by the RDEIR's analysis to account for a risk of spill is also underestimated, thereby underestimating any resulting impacts, including those to agriculture. The mitigation measures proposed (WR-1, WR-2, AQ-1f and BIO-9) are wholly insufficient to address an impact whose severity is even wholly underestimated. The RDEIR must be revised to address these oversights.

(b) Conversion of Agricultural Rangeland to Industrial Use.

Agricultural impacts are considered significant if they impair the agricultural use of other property.[200] Instead of adhering to this clear mandate, the RDEIR provides a brief and unpersuasive analysis that the Project's appropriation of agricultural grazing land for the industrial purposes of the Project would not prove a significant impact.[201] In so doing, the RDEIR both ignores the impact of such displacement of agriculture for at least the next several decades, and forecloses the opportunity to address whether any feasible mitigation measures exist to address such a significant impact. The RDEIR must be revised to correct this deficiency.

(c) Displacement of Goods Required by Rail for Agriculture.

The RDEIR does not adequately address how increased traffic and deliveries of crude oil to the SFR will affect or displace the supply of goods required for agriculture by rail. This "common carrier" issue has arisen recently in the media, and the RDEIR should address this potential and evidently foreseeable impact.

(ii) The RDEIR Underestimates Impact to Water Quality and Supply.

An overall Project shift to refining tar sands at the SFR, a more energy intensive process than current operations, will increase water demand at the Santa Maria facility. That impact is

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[198] *Id.* at 4.2-39.
[199] RDEIR at 4.2-35.
[200] RDDEIR at 4.2-19.
[201] RDEIR at 4.2-34.

unaddressed in the RDEIR. The RDEIR does address, however, the traditional problem of water availability in the Nipomo Mesa area.[202] The South County already suffers from low water levels. The Project's anticipated increase in water usage may jeopardize local water supply and the RDEIR should have addressed this potentially significant impact.

Similarly, as noted above, the water quality impacts and mitigation analysis in the RDEIR is based on an underestimated assessment of the frequency and severity of oil spill. This leaves unexplored and still significant impacts to surface water and groundwater quality. Moreover, the mitigation suggested to manage water quality impacts in the immediate vicinity of the Santa Maria facility is insufficient and would still result in a significant impact.

Mitigation measure WR-2 places the utmost confidence in the staff that implements the Santa Maria Refinery Spill Prevention Control and Countermeasure Plan ("SPCCP"). Essentially, the plan delivers a "first responder" approach that will reduce the impact of a spill in and around water sources that supply the Santa Maria facility to less than significant.[203] However, the RDEIR states elsewhere: "even with (first response) mitigation measures…impacts…could be significant."[204] Other unexplored variables include the volume and location of the spill and the amount of time before that first response.[205] The SPCCP is not laid out with sufficient specificity to provide any assurance that this water quality impact of the Project will be less than significant.

D. The RDEIR Fails to Adequately Analyze the Project's Impacts Related Biological Resources.

The RDEIR fails to adequately disclose, analyze, and mitigate many impacts to biological resources. Specifically, the RDEIR fails to adequately analyze and mitigate (i) impacts at the Project site from construction and operation of the Project; (ii) impacts outside of the Project site resulting from increased rail activity; and (iii) cumulative impacts from increased crude oil shipments.

(i) The RDEIR Fails To Adequately Analyze and Mitigate Impacts to Biological Resources at the Project Site from Construction and Operation.

The RDEIR fails to fully disclose, analyze, and mitigate many of the significant impacts to special-status species at the Project site resulting from construction and operation. Construction of the project would permanently destroy habitat and result in potential mortality for special-status species, including the highly imperiled Nipomo Mesa lupine. Project operation would result in significant new rail traffic at the Project site of up to 250 crude oil trains arriving each year, each carrying up to 80 oil cars, transporting a maximum of 53,532 barrels of crude oil per train.[206] This would result in a significant increase in the probability of oil spills at the Project site, in addition to increased impacts from train-related collisions, noise pollution, light pollution,

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[202] See RDEIR at 4.10-4.
[203] RDEIR at 4.13-25.
[204] RDEIR at 4.2-39.
[205] *See id.* at 4.13-25.
[206] RDEIR at ES-5

and barriers to movement. The RDEIR fails to adequately analyze or mitigate many of these impacts, as detailed below.

(a) The RDEIR Fails To Adequately Analyze and Mitigate Many Construction and Operation-Related Impacts to Special-Status Species in the Project Area.

Under CEQA Guidelines, a project would cause significant adverse impacts to biological resources if it would "have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species."[207] Many Project impacts meet this threshold but were not adequately analyzed or mitigated in the RDEIR.

(1) Nipomo Mesa Lupine.

The Nipomo Mesa lupine *Lupinus nipomensis* is a federally and state-listed endangered species that is limited to one population comprised of approximately six colonies isolated along a two-mile stretch.[208] The species' habitat consists of stabilized backdune supporting central coastal dune scrub. Almost all the habitat for the species is located on the Santa Maria Refinery Property.[209] The Project would destroy 27.5 acres of undeveloped habitat,[210] including 26.5 acres of coastal scrub habitat.[211] As a result, Project construction would directly degrade and destroy some of the last-remaining habitat for the Nipomo Mesa lupine, and potentially destroy plants and seeds in the Disturbance Area. Project operation also significantly increases the risk of an oil spill that could kill individuals, destroy habitat, and potentially result in the extinction of species as acknowledged by the RDEIR.[212]

Although pre-project surveys did not detect plants at the Project site, the RDEIR admits that the survey data were not adequate to detect Nipomo Mesa lupine: "[t]he current determination of presence/absence of Nipomo lupine within the Project Site cannot be adequately determined…."[213] The RDEIR further acknowledges that "a seed bank has the potential to persist within the project site without producing any individuals,"[214] as verified by local species experts, the USFWS, and comments by scientific organizations. Because ground disturbances can stimulate germination of lupine, the RDEIR also acknowledges that construction activities could lead to a flush of plants at the Project site: "there is a potential for this species to occur within the Project site as a result of grading and construction activities associated with the Rail Spur Project."[215]

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[207] CEQA Guidelines, Appendix G.
[208] http://ecos.fws.gov/docs/five_year_review/doc3219.pdf
[209] Id.
[210] RDEIR at 2-7.
[211] RDEIR at 4.4-32
[212] RDEIR at 4.4-44
[213] RDEIR at 4.4-27
[214] RDEIR at 4.4-27
[215] RDEIR at 4.4-27

Although the RDEIR claims that the proposed mitigation measure BIO-1 is adequate to reduce the Project impacts to this highly imperiled species to "less than significant," mitigation under the RDEIR is inadequate in several key regards:

(1) The RDEIR should be revised to consider alternative locations for construction activities in order to avoid disturbing and destroying Nipomo Mesa lupine populations and suitable habitat.

(2) The RDEIR must implement mitigation measures even if the pre-project survey does not detect lupine. BIO-1 irrationally fails to implement mitigation if the pre-project survey does not detect lupine within the Project site.[216] However, the lack of detection in one additional pre-project survey is not sufficient to determine that the site is not occupied by lupine. Lupine can persist as an underground seed bank without producing above-ground individuals.[217] The seeds of the Nipomo Mesa lupine often require scouring in order for germination to occur, so there is a possibility that even with a normal rainfall season, the seeds may not germinate and produce above-ground individuals unless the seeds are scoured.[218] In addition, California is currently in severe drought and it may be several years before California receives "a normal rainfall season" as specified by the mitigation measure. In short, another survey that simply searches for blooming specimens may not prove sufficient to detect this endangered plant. Further, regardless of whether plants are detected, the Project is degrading and destroying a significant portion of remaining habitat for the Nipomo Mesa lupine, and this loss must be mitigated. The Nipomo Mesa lupine, like many annual plants, moves around on the landscape to take advantage of preferred ecological conditions, and occupies different sites from year to year. Thus, the Project site, even if not occupied by plants at present, may have been previously occupied and may be occupied in the future. Consequently, regardless of survey results, the RDEIR should proceed under the assumption that the Project will destroy currently occupied habitat or impact habitat that the lupine would occupy in the near future.

(3) Mitigation measure BIO-1 states that Phillips 66 will coordinate with the County and California Department of Fish and Wildlife (CDFW) to acquire a 2081 Incidental Take Permit (ITP) if the survey determines that the lupine is present. Because surveys may fail to detect species' presence and because the Project will permanently destroy some of the last-remaining habitat for the imperiled Nipomo Mesa lupine, Phillips 66 must apply for and acquire an ITP regardless of whether the survey detects individuals. The ITP must be acquired before certification of the RDEIR because mitigation measures, analyses, or consultation with the CDFW performed *after* certification of this DEIR constitutes *illegally deferred mitigation*.[219]

(4) Under the California Endangered Species Act, the issuance of ITP must ensure that the Project will not jeopardize the continued existence of a State-listed species.[220] . However, the RDEIR acknowledges that the Project has the potential to cause the extinction of the species due

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[216] RDEIR at 4.4-28
[217] RDEIR at 4.4-27; USFWS letter at http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/NOPISCHECKLIST.pdf
[218] USFWS letter at http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/NOPISCHECKLIST.pdf
[219] *See Communities for a Better Environment* v. *City of Richmond* (2010) 184 Cal. App. 4th at 93.
[220] Cal. Code Reg. tit. 14, § 783.4(a)-(b).

to a major crude oil spill: **"**However, highly localized species such as Nipomo Mesa lupine, a federally endangered species, there is a potential that the entire population could be permanently lost or severely damaged in a catastrophic event."[221] Since the potential extinction of a species should be considered jeopardy and cannot be mitigated, the ITP, if issued, must include mitigation measures that will ensure that the Project will not jeopardize the Nipomo Mesa lupine. For example, measures could include the restoration and maintenance in perpetuity of multiple, sufficiently-large (i.e., with a range of microhabitats) suitable habitat areas with restored Nipomo Mesa populations at suitable distances from the Project and Refinery area to escape impacts from a worst-case-scenario oil spill.

(5) To compensate for the *permanent* impacts to Nipomo Mesa lupine and its habitat, the RDEIR should require Phillips 66 to restore and maintain high-quality habitat for the Nipomo Mesa lupine in perpetuity at a ratio *of a minimum* of 3:1, consistent with USFWS standards. Since 26.5 acres of dune scrub habitat would be damaged or destroyed by the Project, a minimum of 79.5 acres of habitat for the Nipomo Mesa lupine should be restored and maintained in perpetuity. This habitat must support restored Nipomo Mesa lupine populations and other native plant populations, and should be maintained in addition to, and not overlapping with, the 53 acres of restored scrub dune habitat specified under the Dune Habitat Restoration Plan. As discussed above, restored habitat areas should be protected from the effects of a worst-case-scenario oil spill from the Project and Refinery. Further, there must be dedicated, long-term funding for the maintenance of the habitat in perpetuity, including long-term monitoring and management of invasive species.

(6) Construction on the Project site may lead to the germination of Nipomo Mesa lupine in the construction zone. The RDEIR must include mitigation measures to identify occurrences of lupine at the construction site and have detailed protocols to protect these individuals.

(7) Because a lupine seed bank is likely present at the Project site, the RDEIR should require that topsoil be removed and stockpiled prior to construction to preserve the seed bank. Consultation should occur with USFWS, CDFW, and other experts to determine how to protect and utilize the seed bank.

(2) Silver Dune Lupine-Dune Heather Shrubland Alliance.

The RDEIR fails to evaluate Project impacts on the imperiled Silver Dune Lupine-Dune-Heather Shrubland Alliance, also called the Silver Dune Lupine-Mock Heather Scrub Alliance,[222] which is comprised of silver dune lupine (*Lupinus chamissonis*) and dune-heather (*Ericameria ericoides*). This plant alliance is listed as G3 S3 and is tracked by the CDFW. The RDEIR fails to disclose that two large areas inhabited by this rare alliance are located immediately adjacent to the Disturbed Area along a ~750 foot border.[223] Due to the proximity of this sensitive plant community to Project construction and operation-related activities, the RDEIR must evaluate the direct and indirect impacts to this alliance from the Project.

[221] RDEIR at 4.4-44.
[222] https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=24716&inline=1 at PDF page 50
[223] RDEIR at Figure 4.4-3

(3) Sensitive Ground-Dwelling Animal Species.

The American badger, coast horned lizard, and slivery legless lizard are among the special-status species which will suffer permanent habitat loss due to the Project and which will either be evicted (badger) or translocated (lizards) from the Project site. Translocation often leads to mortality, and the mitigation measures BIO-3 and BIO-4 do not require any standards for the quality of the relocation sites or monitoring of translocated individuals to determine if these individuals survive. To mitigate for the loss of habitat and potential mortality of these species, the RDEIR should require a minimum of 26.5 acres of suitable habitat be provided, restored, and maintained in perpetuity for these species before the Project is approved. The RDEIR should also require that relocation sites meet species-expert-approved standards to ensure maximum survival probability for translocated individuals.

(4) Burrowing Owl.

Mitigation measures BIO-8a and BIO-8b must follow the full recommendations of the 2012 CDFW Staff Report on Burrowing Owl Mitigation,[224] including survey protocols, buffer area distances for burrows, and vegetation management protocols for mitigation lands.

(b) The RDEIR Fails to Analyze and Mitigate Many Impacts From Increased Rail Traffic at the Project Site.

The RDEIR fails to analyze and mitigate many operational and construction-related impacts at the Project site to special-status species, including impacts from collisions, noise pollution, light pollution, and barriers to movement imposed by Project construction and increased rail activity. The RDEIR must evaluate and mitigate the full range of construction-related and operational impacts to special-status species in the Project area.

(c) The RDEIR Fails to Adequately Analyze and Mitigate Impacts From Oil Spills at the Project Site.

The RDEIR states that the impacts of an oil spill at the Project site are less than significant with mitigation. However, the analysis and mitigation of oil spill impacts at the Project site (BIO-7) are wholly inadequate in several key regards:

(1) The RDEIR does not contain sufficient analysis and mitigation for oil spills resulting from the pipeline. First, the RDEIR contains contradictory statements about the volume of a worst-case spill from the pipeline, which it estimates at 11,000 gallons of crude oil in Section 4.4[225] and at 90,800 gallons in Section 4.7,[226] which is an enormous discrepancy that must be corrected. Second, the RDEIR states that spills along the pipeline outside of the unloading rack "would be contained with an existing road."[227] However, the RDEIR appears to provide no explanation of how a spill would be contained by the road. The RDEIR must provide clear

[224] http://www.dfg.ca.gov/wildlife/nongame/docs/BUOWStaffReport.pdf
[225] RDEIR at 4.4-38
[226] RDEIR at 4.7-43
[227] RDEIR at 4.4-38

mitigation measures to contain a worst-case scenario from the pipeline, if these impacts are to be considered less than significant with mitigation.

(2) The RDEIR remains inadequate in not fully addressing the scope of the company's shift to a different quality of crude oil feedstock and its impacts to biological resources. The shift in feedstock to tar sands oil must be addressed to properly analyze and mitigate impacts to biological resources. It is well-documented that the probability, severity, and consequences of an oil spill depend directly on the chemicals in the crude. Some types of crudes are more challenging to contain and clean up in the event of spill. For example, tar sands crude is heavy, and sinks to the bottom of water bodies that it is spilled into, which is detrimental to aquatic species. Tar sands oil is not only dangerous for its inherent corrosive and acidic properties and for its tendency to sink in water bodies, but because it is generally only transported when blended with toxic "diluents" that are mixed with the viscous tar sands in order to make it more fluid. Spills of heavy, "sinking" crude, like tar sands oil, are notoriously difficult and expensive to clean up, and create lasting and perhaps irreversible impacts to water quality and aquatic ecosystems.[228] Accordingly, the RDEIR must require mitigation measures that address the containment, cleanup, and restoration of oil spills resulting from the crude oil types that the Project will transport and process, such as Canadian tar sands oil.[229]

(3) Mitigation Measure BIO-7 requires Phillips 66 to amend and submit for review and approval to the County Planning Department, its Santa Maria Refinery Spill Prevention, Control and Countermeasure Plan. This amendment and review has not yet occurred, and will not occur until after the close of the CEQA process. However, CEQA requires that formulation of mitigation measures not be deferred until some future time.[230] Numerous cases illustrate that reliance on tentative plans for future mitigation after completion of the CEQA process significantly undermines CEQA's goals of full disclosure and informed decision making.[231] As such, an EIR cannot rely on any management plans, studies, or reports developed after the EIR process.[232] Thus, this mitigation measure cannot comply with CEQA until the County has had an opportunity to review, approve and include that Countermeasure Plan in a revised document.

(ii) The RDEIR Fails To Properly Analyze and Mitigate Impacts to Biological Resources Outside of the Project Site.

The RDEIR's analysis of Project impacts to biological resources outside the Project site suffers from numerous fatal flaws: (1) the RDEIR arbitrarily limits the geographic scope of its off-site biological resources impacts analysis; (2) the RDEIR fails to require sufficient mitigation measures to reduce the impacts of oil spills along the UPRR mainline serving the Project; and (3) the RDEIR fails to analyze and mitigate the impacts from collisions, noise pollution, light pollution, and barriers to movement from increased rail traffic on the rail lines serving the Project.

[228] http://response.restoration.noaa.gov/about/media/oil-sands-production-rises-what-should-we-expect-diluted-bitumen-dilbit-spills.html
[229] RDEIR at Table 2.6
[230] CEQA Guidelines § 15126.4(a)(1)(b).
[231] *Communities for a Better Environment v. City of Richmond* (2010) 184 Cal. App. 4th 70, 92 .
[232] *Id.*

(a) The RDEIR Limits the Geographic Scope of its Off-Site Biological Resources Impacts Analysis.

The RDEIR limits its analysis of the impacts from a crude oil spill along the UPRR mainline to the section of track between the Roseville and Colton rail yards. However, CEQA requires an EIR to discuss the significant impacts that the proposed project will have in the relevant geographic area.[233] Agencies must "provide a reasonable explanation for the geographic limitation used,"[234] and the geographic scope "cannot be so narrowly defined that it necessarily eliminates a portion of the affected environmental setting."[235]

Although the RDEIR labels routes beyond the Roseville and Colton rail yards as speculative, very few branches of the Union Pacific railroad connect crude oil sources to the Project site within California and other Western states. For example, as illustrated in the map below, there are two main rail routes between the Project site and Canadian tar sands sources to the north. Because only a handful of rail lines would serve the Project, the analysis of the potential impacts to special-status species along the UPRR mainlines serving the Project is eminently feasible and foreseeable. As such, the RDEIR must analyze the impacts to special-status species along the mainline beyond the Roseville and Colton yards. This failure is arbitrary and violates CEQA.

Union Pacific Crude-By-Rail Lines.
Source: http://www.up.com/customers/chemical/crude/index.htm

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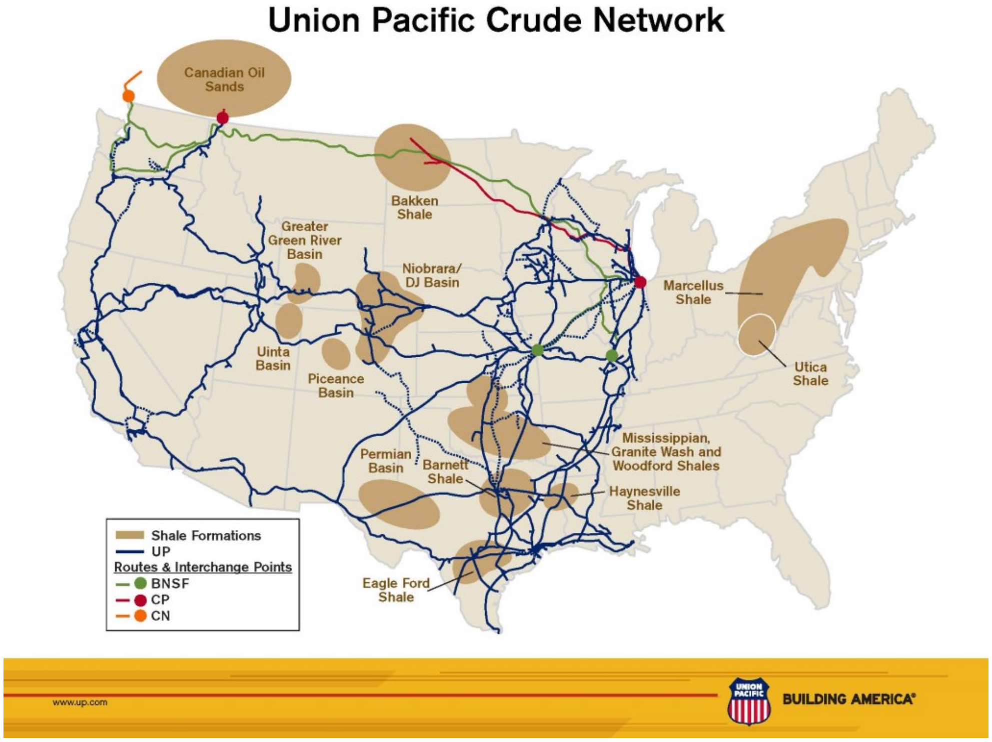
[233] CEQA Guidelines § 15126.2(a).
[234] *Id.* § 15130(b)(1)(B)(3).
[235] *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal. App. 4th 1184, 1216.



(b) The RDEIR's Mitigation Measures are Inadequate to Reduce the Significant Impacts of Oil Spills Along the UPRR Mainline Serving the Project.

The RDEIR classifies the impacts from crude oil spills along the mainline as significant and unavoidable. The tremendous potential for harm is illustrated by the fact that oil spills along the limited section of mainline track between the Roseville and Colton rail yards could impact an estimated 167 sensitive plant species, 219 sensitive animal species, 411 streams and wetlands, 26 waterbodies and 578 wetlands, and 20 sensitive habitats, just within 300 feet of the mainline.[236] As noted by the RDEIR, "depending on the location of an oil spill along the UPRR mainline tracks, there may be no oil spill containment or cleanup equipment immediately available, and it could take some time for emergency response teams to mobilize adequate spill response equipment."[237] This analysis highlights the high probability for significant damage from an oil spill along the UPRR mainline track serving the Project. However, the proposed mitigation measures are completely inadequate. BIO-11 is simply not adequate to lessen the impacts of an oil spill to biological resources. Further, as discussed above, the proposed mitigation measures for the significant increase in risk of crude oil train derailment and spills are also inadequate because the RDEIR (1) applies flawed, under-estimated assumptions regarding the increased risks of crude oil spill(s) and resulting impacts, caused by the Project; (2) fails to adequately analyze the implications of a shift in crude slate on impacts; and (3) illegally defers mitigation in

[236] RDEIR at 4.4-44 to -45.
[237] RDEIR at 4.4-46.

relying on safety precautions and anticipated plans that will not be implemented within a reasonable time.

(c) The RDEIR Fails to Analyze and Mitigate the Impacts From Collisions, Noise Pollution, Light Pollution, and Barriers to Movement Due to Increased Rail Traffic on the Rail Lines Serving the Project.

Although the Project will vastly increase rail activity by up to 250 oil trains trips per year, with the potential for 500 total train trips per year when departures from the refinery are considered (i.e., the same trains coming and leaving), the RDEIR fails to sufficiently analyze the full range of off-site impacts from increased rail traffic to wildlife species along the rail lines serving the Project. Scientific studies have documented that train activity negatively affects wildlife through (1) mortality from collisions with trains; (2) disturbance from noise and artificial light causing stress and behavioral changes; (3) impeding natural movements, thereby restricting the animal's range, making habitat less accessible, and potentially leading to population fragmentation and isolation; and (4) pollution of the physical, chemical, and biological environment, for example through the emissions of contaminants like heavy metals, which can degrade habitat suitability in a much wider zone than the width of the railroad itself.[238] Each of these impacts would be worsened by the significantly increased rail traffic resulting from the Project. The RDEIR must analyze and mitigate each of these impacts along the rail lines serving the Project both within and outside of California. The RDEIR's failure to address these important topics violates CEQA.

1. Mortality From Train Collisions.

Mortality resulting from animal-train collisions has been documented for a wide range of species, including moose,[239] grizzly bears,[240] black bears,[241] wolverines,[242] wolves,[243] deer,[244] pronghorn,[245] tortoises,[246] amphibians,[247] and birds.[248] The frequency of train trips was determined to be the most significant factor in the number of deer-train collisions across study sites.[249] Railroad fatalities can have detrimental impacts on animal populations. For example, train-moose fatalities in the lower Susitna Valley, Alaska, were a primary contributor to population reductions which ranged up to 35% per year.[250]

The BNSF railway in northwestern Montana has long been responsible for killing threatened grizzly bears from the Northern Continental Divide Ecosystem (NCDE) population.

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[238] Jackson 1999.
[239] Andreassen et al. 2005, Gundersen and Andreassen 1998, Gundersen et al. 1998.
[240] Benn and Herrero 2002, Waller and Servheen 2005, Pissot 2007, USFWS 2013.
[241] Pace et al. 2000, Van Why and Chamberlain 2003.
[242] Krebs et al. 2004.
[243] Morner et al. 2005.
[244] AP 2014, Kusta et al. 2011, Kusta et al.2014.
[245] AP 2011.
[246] Iosif 2012.
[247] Budzik and Budzik 2014.
[248] Spencer 1965.
[249] Kusta et al. 2014.
[250] Becker and Grauvogel 1991, Modafferi 1991.

According to recent data, 50 grizzly bears from the NCDE population were documented as killed by train collisions between 1984 and 2013.[251] In 2014 at least two grizzly bears from this threatened population were killed by train collisions.[252] Although BNSF has taken some steps to clean up grain spills attracting bears, grizzly bears continue to be killed along this section of railroad, which has been attributed in large part to the high volume of rail traffic on this line:[253]

> Historically, grizzly bears have been attracted to the railroad by grain that leaked from cars along the tracks or that accumulated at sites of repeated derailments, and grizzly bears have been struck and killed by trains at these sites. Since the mid 1990s, BNSF has been largely successful in cleaning up and reducing the occurrence of grain spills, however, grizzly bears continue to be killed along this section of railroad. Our GPS data did not show any concentrated relocations on the railroad tracks that suggested the presence of an attractant. This research suggests that the coincidence of high rail traffic volume, low highway traffic volume, and natural grizzly bear movement patterns may be partially responsible for the observed patterns of mortality.[254]

As a result, the average number of grizzly bear deaths from train collisions has not declined over time.[255]

2. Noise Pollution.

Noise from rail activity has been found to cause adverse impacts to species. Chronic noise pollution from road, rail, and other anthropogenic activity is an issue of increasing concern.[256] Birds are particularly vulnerable to noise because it can mask their vocal communication, with consequent effects on their health and survival. Schroeder et al. (2012) documented reduced reproductive fitness in birds exposed to chronic noise from generators. Intermittent noise, the expected pattern along a rail line, may also cause stronger effects and decrease the ability of birds to habituate to noise.[257] While some birds may utilize vocal adjustments in response to chronic noise pollution, those adjustments are likely to have direct and indirect fitness costs.[258]

3. Barriers to Movement.

Railways can act as barriers to movement that can result in population fragmentation and isolation. Increased train traffic can increase the impact of the barrier. For example, studies indicate that railways act as a barrier to movement for the federally threatened grizzly bear population in the Northern Continental Divide Ecosystem (NCDE) in northwest Montana.[259]

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[251] USFWS 2014.
[252] Daily Inter Lake 2014.
[253] Waller and Servheen 2005.
[254] Waller and Servheen 2005: 997.
[255] USFWS 2014.
[256] Morley et al. 2014.
[257] Blickley et al. 2012.
[258] Read et al. 2014.
[259] Waller and Servheen 2005, Kendall et al. 2009.

Kendall et al. (2009) found evidence for population fragmentation across the western side of the BNSF rail line and Highway 2 corridor between Glacier National Park and National Forest lands. Population differentiation across the corridor indicated that reduced genetic interchange was occurring. Waller and Servheen (2005) similarly found that train traffic posed a significant movement challenge for bears. Furthermore, their research indicated that the high rail traffic volume was particularly problematic for bear mortalities:

> While grizzly bears appeared to make behavioral adjustments to temporal patterns of highway traffic volume, they were faced with a different situation along the railroad. During hours of low highway traffic, when grizzly bears were choosing to cross US-2, railroad traffic was high. Trains were more frequent, longer, and faster at night than during daylight hours. Furthermore, rail traffic was greater during fall when bears were in hyperphagia. This situation arose for a number of reasons. First, most track maintenance work was accomplished during daylight hours; thus, freight traffic was often curtailed during the day to allow track work to proceed. Second, arrival times for freight trains depended partially on their departure time. Freight trains loaded on the Pacific coast (approx 800 km to the west) during the day left in the evening and arrived in our study area at night the next day, 24–36 hr later. The result was that grizzly bears had to contend with high railroad traffic when highway traffic was lowest. We observed greater grizzly bear mortality caused by trains than that caused by cars on the highway.[260]

Railroads have also been shown to inhibit movement of bumblebees[261] and pronghorn.[262] Fenced railroads in Arizona posed movement barriers that isolated pronghorn into different populations and shaped home ranges, resulting in population fragmentation.[263]

(iii) The RDEIR Fails to Adequately Analyze and Mitigate Cumulative Impacts of Increased Crude Oil Shipments on Biological Resources.

The RDEIR acknowledges that the cumulative impact of an oil spill from the Project and the other crude oil shipment projects listed in Table 3-1 would be significant and unavoidable.[264] The RDEIR should have similarly analyzed the cumulative impacts from recent, current, and proposed projects on the risk of collisions, noise pollution, light pollution, barriers to movement, and other impacts resulting from increased rail activity along the mainline track serving the Project.

E. The Project is Inconsistent with State and Local Plans.

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[260] Waller and Servheen 2005: 997.
[261] Bhattacharya et al. 2003.
[262] Ockenfels et al. 1997.
[263] *Id.*
[264] RDEIR at 4.4-49

An EIR must discuss any inconsistencies between the proposed project and applicable general plans, specific plans, and regional plans.[265] This necessarily includes the County of San Luis Obispo's General Plan and other applicable state and federal regulations.

The RDEIR fails to adequately discuss potential inconsistencies with applicable plans, policies, and regulations, including (1) the San Luis Obispo County General Plan, (2) Contra Costa County's Industrial Safety Ordinance, (3) the United States Chemical Safety Board, OSHA regulations, and other federal guidance regarding risk analysis and hazards prevention, and (4) the California Global Warming Solutions Act (AB 32).

The San Luis Obispo County General Plan sets forth goals to improve the environment, based on public, community-based input from County Residents. The Plan sets forth goals relating to the community's expressed needs to see a decrease in air pollution, decrease in traffic and traffic related noise, and decreased industrial development.[266] The Project, however, will increase all of those issues, wholly conflicting with the General Plan's over-arching environmental goals. Indeed, the RDEIR notes in the Appendix G that the Project is potentially inconsistent with ten of the General Plan's policy goals, including reducing air pollution, minimizing toxic exposures, limiting risks to public safety, promoting development of renewable energy resources, and preventing exposures to hazardous substances.[267] In addition to being inconsistent with the County's General Plan, the Project is also incompatible with surrounding land uses—most importantly, with surrounding residential land uses, where the Project would significantly increase cancer health risks, even with mitigation measures in place.[268]

Additionally, because this Project is integrally related to the Propane Fuel Recovery Project at the Refinery's Rodeo facility, and because the two facilities are connected by pipeline, what takes place at the Santa Maria facility impacts the Rodeo facility, triggering Rodeo and Contra Costa County Local Plans and Ordinances. By increasing regional and state processing of and reliance on fossil fuels, the Project conflicts with Contra Costa County's General Plan, to the extent that plan sets goals to increase the usage of renewable energy such as wind and solar.[269] The Project's switch to denser, higher sulfur crude also conflicts with the Contra Costa County Industrial Safety Ordinance's Inherently Safer Systems requirement.[270]

Further, in order to provide such an adequate investigation and discussion of potential impacts of refining a lower quality oil feedstock as required by CEQA,[271] it would be reasonable for decisionmakers to determine consistency with federal recommendations addressing the same shift in industry practice. The Project as proposed in the RDEIR fails to meet such federal

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[265] CEQA Guidelines § 15125(d).
[266] SLO County General Plan, Adopted: August 1994, Revised: June, 2010, Chapter 1, Land Use, available at: http://www.slocity.org/communitydevelopment/download/unifiedgeneralplan/Chapter1-Land%20Use%20June2010.pdf.
[267] *See* RDEIR App. G, Table G-1.
[268] *See* RDEIR at 4.3-65, Figure 4.3-7.
[269] *See generally*, Contra Costa County General Plan, 2005-2020, Adopted January 18, 2005, Reprinted July, 2010, available at: http://contra.napanet.net/depart/cd/current/advance/GeneralPlan/General%20Plan.pdf.
[270] *See* Contra Costa County Ordinance Chapter 450-8, available at http://cchealth.org/hazmat/pdf/iso/2006_iso_official_code_complete.pdf.
[271] CEQA Guidelines § 15125(c).

guidance. In addition, the Project as proposed also fails to meet the requirements of the State's GHG reduction goals.

As noted above, the U.S. Chemical Safety Board (CSB) has explicitly addressed the increased risks of corrosion in refineries due to refining a heavier oil feedstock. In particular, the CSB has identified the risk of catastrophic and hazardous failure from running higher sulfur crude in existing refineries built before 1985.[272] The CSB also found that such sulfur corrosion is not a new phenomenon, and that the petroleum industry is well aware of its potential to cause serious impacts on refinery equipment.[273] The RDEIR fails to recognize the CSB's analysis and fails to address the proposed recommendations made by the CSB. The RDEIR should be revised to properly address similar and foreseeable issues of corrosion as identified at the Chevron Richmond Refinery, which lead to the catastrophic August 2012 Chevron Richmond Refinery fire.[274]

Moreover, because there will be an increase in the presence of harmful chemicals, raising serious safety and hazards concerns, the Project has the potential to conflict with the Occupational Health and Safety Act (OSHA) employee protection standards, as well as the President's August 2013 Executive Order (EO) to improve chemical safety and security.

Finally, the Legislature has established that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California."[275] With AB 32, California has set its objective to meet 1990 emission levels of GHGs by 2020. The RDEIR's analysis does not provide enough information regarding whether the Project will meet such a state priority. The RDEIR's analysis does not provide enough information regarding whether the Project will meet such a state priority. In particular, "the increase in emissions of criteria pollutants and greenhouse gases from most fired sources due to tar sands bitumen derived semi-refined products refined at Rodeo should have been included in the emission inventory for the Rail Spur Project."[276] Absent this data, it is impossible for the RDEIR to describe whether the Project will meet, or even hinder, California's GHG reduction goals. Although the RDEIR includes a thorough discussion of California's regulatory framework to combat climate change,[277] without a sufficient GHG analysis, no decisionmaker can come to any sensible conclusion regarding how the impacts of this Project affect those goals.

The RDEIR fails to address the above examples of the Project's conflicts with local, State and Federal plans. Given this fundamental failure, the RDEIR should be redrafted and recirculated with a complete discussion of Project inconsistencies with applicable plans, policies, and regulations.

V. THE RDEIR FAILS TO ADEQUATELY ANALYZE THE PROJECT'S CUMULATIVE ENVIRONMENTAL IMPACTS.

[272] *See* Chemical Safety Board, Chevron Richmond Refinery Interim Investigation Report, April 2013, available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf
[273] *Id*., at 15.
[274] *See* Chemical Safety Board, Chevron Richmond Refinery Interim Investigation Report, April 2013, *supra*.
[275] Assembly Bill (AB) 32, California Global Warming Solutions Act, Cal. Health & Safety Code § 38501(a).
[276] Fox Revised Santa Maria Report at 13.
[277] RDEIR at 4.3-29 to -32.

Once again, the RDEIR hides behind an unpersuasive assertion of federal preemption in order to avoid an analysis and possible future application of more realistic, feasible and beneficial mitigation measures. It does this by again focusing simply on cumulatively relevant locomotive operations.[278]

However, CEQA requires an EIR to discuss all of a Project's significant cumulative impacts.[279] A legally adequate cumulative impacts analysis views a particular project over time and in conjunction with other related past, present, and reasonably foreseeable future projects whose impacts might compound or interrelate with those of the project at hand. "Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time."[280] These projects do not have to be from the same class of project.

A project has a significant cumulative effect if it has an impact that is individually limited but "cumulatively considerable."[281] "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."[282] 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."[283] The RDEIR fails to meet this requirement by unnecessarily limiting its analysis of potential sources of cumulative impacts. Just like the overall analysis underlying the RDEIR, this is not simply a transport infrastructure project. The other crude by rail projects listed in the RDEIR are also not simply transport infrastructure projects. All of these projects reflect the industry intention to switch to a lower quality of crude oil feedstock. Those create different and greater degrees of pollution that any environmental document must analyze cumulatively. The RDEIR's analysis focuses solely on cumulative impacts associated with that narrower transport element, or, the locomotive and associated emissions, for instance, increased traffic on the railway mainline. Foreseeable emissions include increased operational emissions from the inevitable refining of that lower quality oil feedstock transported.

In addition, even the list of reasonably foreseeable future projects, including other crude by rail projects considered in the RDEIR is under inclusive, especially in light of the potential geographic scope of certain potentially significant impacts. Although the RDEIR mentions some of the current crude by rail projects and proposals, and purports to analyze the cumulative environmental impacts from them, it does not come close to disclosing the full scope of the staggering environmental impacts they will have on California.[284] The RDEIR's Table 3.1 purports to disclose cumulative projects to a sufficient degree.[285] It does not.

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[278] RDEIR at 4.3-76.
[279] CEQA Guidelines § 15130(a).
[280] CEQA Guidelines § 15355(b).
[281] *Id*. §§ 15065(a)(3), 15130(a).
[282] *Id*. § 15065(a)(3).
[283] *Communities for a Better Env't v. Cal. Res. Agency* (2002) 103 Cal.App.4th 98, 114.
[284] *See* RDEIR Table 3.1.
[285] RDEIR at 3-3.

Five other projects omitted from adequate consideration in the RDEIR's analysis of cumulative environmental impacts include[286]:

(i) **Phillips 66 Ferndale, Washington Crude Unloading Facility Project.**

Phillips 66 was recently issued a permit to construct a new crude rail unloading facility at its Ferndale Refinery in Washington. The RDEIR must state whether this Project anticipates, depends on, or is in any other way related to the Washington project.

(ii) **Phillips 66 Rodeo Propane Fuel Recovery Project.**

In particular, despite the clear relationship between the Santa Maria projects and the Rodeo Refinery project described above, the RDEIR fails to evaluate the Project's cumulative impacts of Santa Maria semi-refined products in Rodeo. These include a cumulatively considerable increase in criteria and toxic air contaminant air emissions and greenhouse gas emissions, and the cumulative environmental impacts of refining increased volumes of tar sands at the SFR.

(iii) WesPac Pittsburg Energy Infrastructure Project.

WesPac Energy–Pittsburg LLC (WesPac) proposes to modernize and reactivate the existing oil storage and transfer facilities located at the NRG Energy, Inc.(NRG, formerly GenOn Delta, LLC) Pittsburg Generating Station. The proposed WesPac Energy– Pittsburg Terminal (Terminal) would be designed to receive crude oil and partially refined crude oil from trains, marine vessels, and pipelines, store oil in existing or new storage tanks, and then transfer oil to nearby refineries, including the Phillips 66 San Francisco Refinery's Rodeo facility.[287]

The Terminal Project consists of the modernization and reactivation of the following components at the NRG facility: (1) marine terminal; (2) onshore storage terminal, including both East and South Tank Farms; and (3) the existing San Pablo Bay Pipeline. In addition, the project consists of the construction and operation of new facilities, including: (1) Rail Transload Facility; (2) Rail Pipeline; (3) KLM Pipeline connection; and (4) new ancillary facilities, including an office and control building, warehouse, electrical substation, and others as described below.[288]

For the delivery of crude oil and partially refined crude oil by train, a new Rail Transload Operations Facility would be constructed on a 9.8-acre vacant rail yard, to be leased from BNSF Railway Company. All products handled at the facility would be transported by rail, ship, barge, or pipeline; no products would be transported by truck as part of the proposed project.[289] The Terminal would operate with an average throughput of 242,000 barrels (BBLs)1 of crude oil or partially refined crude oil per day, and would have a maximum capacity throughput of 375,000

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[286] This list does not include the nearby oilfield expansion project proposed by Freeport McMoran, which is under construction and discussed in the Fox Santa Maria Report.
[287] WesPac RDEIR at 2.0-1.
[288] *Id*. at 2.0-4.
[289] *Id*. at 2.0-1.

BBLs per day.[290] The total annual throughput for the entire Terminal would be approximately 88,300,000 BBLs of crude oil and/or partially refined crude oil per year.[291]

As mentioned above, the SFR is one of the refineries that may receive crude oil and/or deliver-crude oil to the Terminal.[292] Although the RDEIR *lists* this project in Table 3.1, it still fails to include any adequate *analysis* of the WesPac project in the cumulative impact analysis (outside of anticipated rail traffic). Nevertheless, the physical construction and *operation* of this facility will contribute to cumulative environmental impacts and because it could facilitate greater amounts of not just crude delivered to or from the SFR, but a lower quality crude with associated increased emissions and hazards delivered to or from the SFR. The RDEIR must be revised to take into account each of the cumulative projects that has the potential to result in cumulatively considerable environmental impacts. Furthermore, the RDEIR must identify feasible mitigation measures capable of reducing all of the Project's associated and foreseeable environmental impacts.

(iv) Kinder Morgan Richmond Terminal.

The RDEIR omits any mention of the Kinder Morgan terminal in Richmond, California. The RDEIR also omits any discussion of the possibility of ship to rail deliveries of crude oil feedstock, which would directly implicate deliveries to the Port of Richmond and then to the SFR via the Kinder Morgan facility. The cumulative impact of this terminal would be utterly foreseeable, and the RDEIR should have analyzed this possibility, and at a minimum, the additional cumulative impact the Project would add to the emissions of toxic air contaminants, GHGs, or other pollutants, or increase in hazards in conjunction with operation of the Kinder Morgan terminal's existing transport of crude by rail.

(v) Phillips 66 Pipeline Project.

Table 3.1 also discloses the Phillips 66 Pipeline Project. The proposed project would transport crude oil from the Arroyo Grande oil field to the Santa Maria Facility.[293] The RDEIR's cumulative impacts analysis must analyze whether this Project would displace the need for this other source of crude oil feedstock for the SFR.

A. Climate Change Implications.

Furthermore, it is important to acknowledge that climate change is the classic example of a cumulative effects problem; emissions from numerous sources combine to create the most pressing environmental and societal problem of our time.[294] As one appellate court recently held, "the greater the existing environmental problems are, the lower the threshold for treating a project's contribution to cumulative impacts as significant."[295]

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[290] *Id*. at 2.0-2.
[291] *Id*.
[292] *Id*.
[293] RDEIR at 3-4.
[294] *Kings County Farm* ("Perhaps the best example [of a cumulative impact] is air pollution, where thousands of relatively small sources of pollution cause serious a serious environmental health problem.").
[295] *Communities for Better Env't v. Cal. Res. Agency* (2002) 103 Cal. App. 4th 98, 120.

Canadian tar sands crude is considered to be the dirtiest, most carbon-intensive fuels on the planet. NASA climatologist Jim Hansen explains:

> With today's technology there are roughly 170 billion barrels of oil to be recovered in the tar sands, and an additional 1.63 trillion barrels of worth underground if every last bit of bitumen could be separated from sand. "The amount of CO2 locked up in Alberta tar sands is enormous," notes mechanical engineer John Abraham of the University of Saint Thomas in Minnesota, another signer of the Keystone protest letter from scientists. "If we burn all the tar sand oil, the temperature rise, just from burning that tar sand, will be half of what we've already seen"—an estimated additional nearly 0.4 degree Celsius from Alberta alone.

Notwithstanding the clear evidence documenting the effect that petroleum-refining has on GHG emissions, and enormous increase that would result from the transport, processing and refining of tar sands crudes. The RDEIR should have acknowledged the complete degree of the company's switch to this different quality crude oil feedstock and provided a suitable cumulative impacts analysis.

B. Environmental Justice Implications – A Tremendous Cumulative Impact on an Already Over-Burdened Community

Finally, it is important to note the cumulative impact of pollution on the local community. As illustrated throughout this comment, this Project as proposed will increase pollution locally, essentially relying on ERCs to mitigate a majority of pollution that occurs locally. Increased emissions in the impacted Project area will inevitably result in greater cumulative impacts especially for the communities surrounding the refinery. Santa Maria, its surrounding communities including the cities of Nipomo and Guadalupe, as well as Rodeo, and its surrounding communities, have all been identified by the Office of Environmental Health and Hazards Assessment (OEHHA) as bearing a concentrated burden of health hazards resulting from various pollution sources, including the Santa Maria and Rodeo Refinery facilities.[296] This means that impacts, which may appear insignificant by themselves, are indeed significant when considered in the context of and in combination with existing sources of environmental impacts, which often tend to be more concentrated in some areas, such as those where these two facilities are located.

With regard to the Santa Maria facility, Santa Maria, Nipomo and Guadalupe score high on the OEHHA's indicators used to highlight environmental justice, or highly burdened

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[296] OEHHA Cal Enviro Screen 1.1 (amended), Statewide Zip code Results, Nipomo, Guadalupe, Santa Maria, available at:
http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56, and Zip code Results, Rodeo, available at:
http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56,

communities.[297] Some of these indicators or factors include: number of pollution sources, including active and inactive waste cleanup sites; heavy industrial facilities, such as refineries; and hazardous waste, groundwater waste, presence of ozone and ozone precursors in the ambient environment, among others. The public health indicators examined further include, *inter alia*, asthma and low birth weight rates.

Nipomo has a high concentration of solid waste sites, including both active and in-active clean-up sites.[298] This means that the residents of the Nipomo already bear the burden of existing concentrated mal-odors, methane and carbon dioxide emissions from those facilities alone.[299] Nipomo also scores within the top 3% of the state's highest Toxic Release Inventory chemical burdens and within the top 1% of the state's burden from pollution caused by pesticide use.[300] Guadalupe is identified as a linguistically isolated city, and similar to Nipomo has a high concentration of hazardous waste facilities.[301] It also bears the impacts of a high concentration of emissions from other concentrated pollution stationary sources, such as the Santa Maria Refinery.[302] The combined impacts of these factors renders that city and the surrounding area, a particularly vulnerable community that suffers a high health burden from existing contaminating sources. [303]

Much like Nipomo and Guadalupe, Rodeo also ranks in the top 8% of the state's highest concentration of hazardous waste facilities, has a high concentration of contamination from Toxic Release Inventory chemicals, ranking in the top 3% for that factor.[304] Moreover, Rodeo also suffers from a high rate of low birth weights and asthma, ranking in the top 1 and 16% for each, respectively.[305]

The particular vulnerabilities of these communities, and the existing pollution burdens that exist in each, even without the added impacts of refining tar sands at the SFR, in combination with its related components in both the Throughput Increase and Propane Fuel Recovery Projects, demand a full analysis of the additional burden that will result from this Project. Only then can any decision making body properly ascertain the degree of significance of the cumulate impact of this Project, and the cumulative local impact is especially important. This analysis is an integral component of CEQA, one that the RDEIR illegally omitted.[306]

VI. THE RDEIR FAILS TO ANALYZE A REASONABLE RANGE OF PROJECT

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[297] *See*, OEHHA Cal Enviro Screen 1.1, Statewide Zip code Results, Nipomo, Guadalupe, Santa Maria, *supra*, at: http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56.
[298] OEHHA Cal Enviro Screen 1.1 (amended), Statewide Zip code Results, available at: http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56.
[299] OEHHA, California *Communities Environmental Health Screening Tool, Version 1.1 Guidance and Screening Tool*, September 2013 Update, Matthew Rodriguez, Cal EPA, and George V. Alexeeff, Ph.D., Director of OEHHA, available at: http://oehha.ca.gov/ej/pdf/CalEnviroscreenVer11report.pdf.
[300] *See* OEHHA Cal Enviro Screen 1.1, *supra*, and *see, Id.*
[301] *Id*.
[302] *Id*.
[303] *Id*.
[304] OEHHA, Cal Enviro Screen 1.1 (amended), Statewide Zip code Results, Rodeo, at: http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56.
[305] *Id*.
[306] CEQA Guidelines §§ 15064(d), 15125(c); *see also, Kings County Farm Bureau*, 221 Cal. App. 3d 692, 729.

ALTERNATIVES.

An EIR is not considered complete unless it has considered a "reasonable range of potentially feasible alternatives" to a proposed project.[307] The feasibility of an alternative is determined if it is "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."[308] An EIR's alternatives analysis is considered satisfactory as long as it contains "sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project."[309] "The degree of specificity required in an EIR 'will correspond to the degree of specificity involved in the underlying activity which is described in the EIR.'"[310] Therefore, an EIR must contain more details for a specific project than an EIR for an approval of a general plan.[311]

The RDEIR fails to evaluate a reasonable range of alternatives and consider the alternatives in sufficient detail to allow a meaningful analysis and evaluation.[312] The RDEIR analyzed only two alternatives—a no project alternative, a loop rail unloading configuration alternative, and a reduced rail delivery alternative.[313] The RDEIR also identified three other alternatives that were considered, but rejected because they were either not technically feasible, failed to attain the basic objectives of the project, or would result in greater impacts than the proposed project. These rejected alternatives include two crude transportation alternatives (trucking and marine transport) and an alternative rail unloading sites alternative.[314]

CEQA does not have an established legal standard for the scope of the alternatives considered, but courts have held the scope of the alternative "must be evaluated on its facts," on a case-by-case basis.[315] The rule of reason judges the scope of the alternatives.[316]

Parties objecting to the EIR are not responsible for formulating alternatives for consideration—the lead agency bears this burden.[317] Objecting parties will rarely have access to the same information that the lead agency does, and thus will be limited in their ability to suggest sufficiently detailed and specific alternatives.[318] The lead agency is in a better position to make these suggestions since they probably have greater access to information than the objecting parties.[319] However, the following discussion illustrates the inadequacy of the alternatives analysis contained in the RDEIR.

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[307] CEQA Guidelines § 15126.6(a).
[308] Cal. Pub. Res. Code § 21061.1.
[309] CEQA Guidelines § 15126.6(d).
[310] *Al Larson Boat Shop, Inc. v. Bd. of Harbor Commrs.* (2d Dist. 1993) 18 Cal.App.4th 729, 746 (quoting CEQA Guidelines § 15146).
[311] *See id.*
[312] *See* CEQA Guidelines § 15126.6(d).
[313] See RDEIR Table 5.10, p. 5-53.
[314] *See* RDEIR at 5-2.
[315] *Citizens of Goleta Valley v. Bd. of Supervisors* (1990) 52 Cal.3d 553, 566.
[316] CEQA Guidelines § 15126.6(a).
[317] *See Laurel Heights I*, 47 Cal.3d at 406.
[318] *Id.*
[319] *See id.*

The RDEIR fails to consider an alternative that would avoid putting people in unnecessary danger during the transport of the volatile crude. The Project as proposed involves locomotives travelling through highly densely populated areas of central California, including Sacramento. This route exposes a large population to air emissions associated with locomotive operation, and greatly increases the human health and safety risks of potential accidents or spills. Along the route is the Sacramento-San Joaquin Delta. The delta is home to a number of native Californian species, used for major agricultural purposes in the state, and is a major water source for much of the state. A spill or train derailment in this area, of any magnitude, risks the health and safety of not only those in the surrounding area, but all over the state as well.

Alternative modes of transporting crude oil from across North America should also be analyzed more thoroughly. Though two options were preliminarily considered, these alternatives were not fully analyzed in the RDEIR. Finally, given the dwindling local supply of crude oil feedstock for the Santa Maria facility and the potentially massive overhaul to a different quality feedstock on account of this and other connected Phillips 66 projects, the point must be made that the existing facility will soon outlive its purpose. Thus, Phillips' proposal presents a choice: should it be allowed to extend this refining operation for several decades by re-purposing the Santa Maria facility to process tar sands oil that is imported by rail? The RDEIR should have evaluated, instead of obscuring, this choice and its environmental implications. The RDEIR failed to include this and other reasonable alternatives in its analysis, and the document should be revised and recirculated to correct these deficiencies.

VII. CONCLUSION

For the reasons stated above, the RDEIR remains inadequate under CEQA. The County must substantially revise and recirculate the document in order to correct its numerous defects.

It is important to note that the RDEIR does not provide a sufficient basis for the County to make a statement of overriding considerations. In order to approve an EIR with significant and unavoidable impacts, the lead agency must also make a statement of overriding considerations explaining why the benefits of the project would outweigh the significant environment impacts.[320] This statement must be supported by substantial evidence in the record.[321] This RDEIR identifies a number of impacts that it has found to be significant and unavoidable, including significant deterioration of air quality in San Luis Obispo County and along the UPRR mainline, increased risk of catastrophic train derailments and explosions, and degradation of sensitive biological resources. In order to approve the RDEIR with these significant impacts unmitigated, the County must make a finding that the benefits of the project outweigh those impacts.[322]

There is no basis for a finding that the benefits of the Project would outweigh its significant costs to the environment and to the health and safety of the thousands of people living in San Luis Obispo County and along the UPRR main line. The RDEIR offers an obscured project objective in an apparent attempt to suggest that the County develop a statement of

[320] CEQA Guidelines §§ 15092, 15093.
[321] *Id.* § 15093(b).
[322] *Id.*

overriding considerations, include allowing the refinery to obtain a range of competitively priced crude oils, and "[m]aximiz[ing] the use of existing infrastructure and resources to support the economic vitality of the County and State."[323] However, the RDEIR later notes that "[g]iven the limited increase in local expenditures associated with the Rail Spur Project, the economic growth associated with future development at the proposed project site would not be significant," and "minimal new operational employment would be associated with the Rail Spur Project."[324]

Finally, the County is not presented with a complete picture of this Project. The RDEIR restricts the Project in scope, diminishing its impacts, and making any weighing or calculation of the costs and benefits of the Project impossible. Any determination to the contrary is not supported by substantial evidence, violates CEQA, and would display a total disregard for public and worker health and safety. For these, and the reasons listed above and detailed in the accompanying attachments, the County must reject this RDEIR, revise its flawed analyses and recirculate it for public comment under the procedures for a programmatic level EIR.

Sincerely,

Roger Lin
Yana Garcia
Heather Lewis
on behalf of Communities for a Better Environment

Devorah Ancel
on behalf of Sierra Club

Shaye Wolf
on behalf of the Center for Biological Diversity

Ethan Buckner
on behalf of ForestEthics

Comment supported by:

The California Nurses Association
The City of Berkeley
West Oakland Environmental Indicators Project
Crockett Rodeo United to Defend the Environment (C.R.U.D.E.)
West Oakland Environmental Indicators Project
Energy-Climate Committee, Sierra Club California
South Asian Americans for Climate Justice
The SunFlower Alliance
Wellstone Democratic Club
Citizens Against Hazardous Oil Trains (Fremont)
Idle No More SF Bay Area
350 Bay Area
350 Silicon Valley
GreenAction for Health and Environmental Justice
San Francisco Baykeeper
Pittsburg Defense Council

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[323] RDEIR at 2-1 to -3.
[324] RDEIR at 6-2.

Martinez Environmental Group
Bay Area Refinery Corridor Coalition
Benicians for a Safe and Healthy Community
East Yard Communities for Environmental Justice
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Phillips 66 Los Angeles Refinery

BEFORE THE GOVERNING BOARD OF THE

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

In the Matter of **The South Coast Air Quality Management District's December 12, 2014 Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project**	**PROJECT PROPONENT PHILLIPS 66 COMPANY's OPPOSITION TO APPEAL OF APPROVAL AND CERTIFICATION OF THE FINAL NEGATIVE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT FILED BY COMMUNITIES FOR A BETTER ENVIRONMENT**

Project proponent Phillips 66 Company (Phillips 66) opposes Communities for a Better Environment's (CBE) Appeal to the South Coast Air Quality Management District (District) Governing Board of Approval and Certification of the Final Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant Crude Oil Storage Capacity Project (Project). The Executive Officer, the final decisionmaking authority for permit issuance, properly reviewed and adopted the Negative Declaration and approved the project in full compliance with the California Environmental Quality Act (CEQA). The appeal is not proper and there is no legal basis for the request.

I.
INTRODUCTION

On November 21, 2012, Phillips 66 filed an application with the District to construct a new crude storage tank at its Los Angeles Refinery (Refinery) Carson Plant to enable the Refinery to offload a ship with a capacity larger than 400,000 barrels (e.g., Aframax at 720,00-barrel capacity and Suezmax at 1,000,000-barrel capacity) (referred to in this document as a "large tanker") in one visit to Berth 121 in the Port of Long Beach (marine terminal).[1,2] The large tankers are typically used for longer ocean voyages, and the Refinery receives crude in these tankers from South America, the Middle East and Alaska. Currently, because the Refinery's Carson Plant does not have a tank large enough to hold a fully-loaded large tanker, fully-loaded large tankers must visit Berth 121 twice to unload their contents. Part of the crude cargo is offloaded during the first visit but the large tanker must then go out to anchor in the harbor and wait until a sufficient amount of crude has been used in the Refinery so that there is enough space in the Carson Plant crude storage tanks to finish offloading the remaining crude on the large tanker. This process can take several days. As a result, Phillips 66 incurs demurrage costs that must be paid while the large tanker is at anchor, during which the large tanker continues to emit NOx, SOx, particulate matter and other pollutants into the Southern California air basin as it waits to offload the remaining cargo. Last year alone the Refinery paid nearly $4 million in demurrage costs.

The Project would allow the large tankers to unload crude in one visit, thus cutting demurrage costs and reducing port emissions. The large tankers were designed to reduce transportation costs of crude by taking advantage of "economies of scale"; the more crude that can be transported at once on a longer voyage, the lower the cost per barrel of transporting the crude.

The District circulated a draft Negative Declaration for the Project on September 10, 2013 for a 30-day review period. The draft Negative Declaration concluded that the proposed Project would not result in any significant impacts to the environment.

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[1] Phillips 66 receives crude oil transported via marine waters and for utilization at the Refinery's Carson Plant at Berth 121 in the Port of Long Beach.

[2] Phillips 66 submitted a revised application on March 11, 2013.

CBE filed comments on October 9, 2013. These comments asserted that the Negative Declaration failed to fully and accurately describe the whole of the project and therefore did not properly evaluate potential impacts of the project. CBE provided corporate quarterly and annual investor statements and other financial documentation that, in general, describe a corporate strategy to process increasing amounts of what the company calls "advantaged crudes" at its eleven United States refineries. When Phillips 66 corporate documents utilize the term "advantaged crudes," they mean crude oil that costs less than the cost of the benchmark Brent crude. In order to use these documents to support its arguments, however, CBE had to create an entirely new and incorrect definition for the term "advantaged crudes" – CBE's comments asserted that advantaged crude means Bakken and Canadian tar sands crudes. Applying its own definition to Phillips 66's corporate statements, CBE asserted that Phillips 66 intended to use the Project intended to increase the amount of these crudes refined at the Los Angeles Refinery. CBE also alleged that the use of Bakken and Canadian tar sands crudes would cause more emissions of criteria and toxic air pollutants.

The District reviewed the comments by CBE and fully responded to each comment.[3] The District's Executive Officer is the decision-making authority for permits issued by the District and, thus, the accompanying CEQA document, in accordance with the California Health and Safety Code, CEQA and District rules and regulations. The Executive Officer determined that the none of the information provided by CBE constituted substantial evidence "that the proposed project may have one or more significant effects."[4] In particular the Executive Officer found that, while the Project reduced costs of transporting some crudes, it was not particular to any specific type of crude, that the Refinery must run a blend of crudes in order to meet the particular specifications and equipment limitations of the Refinery, that the Refinery was already processing heavy Canadian crudes including tar sands within the blend of crude that it runs, that in order to run Bakken crude or Canadian tar sands crudes in amounts that changed the blend Phillips 66 would

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[3] Contrary to CBE's contentions, this lengthy and detailed review was not "rubber-stamping."

[4] *See*, Response to Comment 3-1, page F-94 of the final Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant Crude Oil Storage Capacity Project.

need to make modifications to Refinery processing units, and that no such modifications were contemplated. Therefore, the Executive Officer approved the Negative Declaration on December 12, 2014 and issued the permit.

On January 2, 2015, CBE wrote a letter to the Executive Officer requesting that the Executive Officer withdraw the Negative Declaration. The request did not contain any new evidence of a significant impact. The District declined to withdraw the Negative Declaration on January 9, 2015.

On January 9, 2015 CBE filed its petition to the Governing Board to review the Executive Officer's determination, "deny certification, withdraw and re-consider" the approval, and included additional information not previously submitted to the decisionmaking authority, the Executive Officer.

II.
REASONS FOR DENIAL OF THE APPEAL

A. The Request for Appeal by CBE is Improper and Should be Denied.

In accordance with Section 42300 of the California Health and Safety Code, and District Rules 201 and 203, the Executive Officer is the final decisionmaking authority for the issuance of permits. CEQA requires that the decisionmaking authority for the project, in this case the permit, must be the same authority who reviews and approves the Negative Declaration. CEQA Guidelines Section 15074(b). Therefore, a request to have the Governing Board review the CEQA determination on a permit that has been approved by the Executive Officer is improper and would not comply with the requirements of CEQA.

1. CEQA Requires that the Decisionmaking Authority for the Project Also Make the CEQA Determination for the Project.

The CEQA Guidelines specify that the "decisionmaking body" of a public agency must review and consider a final EIR or approve a negative declaration prior to approving a project. CEQA Guidelines Section 15025(b). CEQA Guidelines Section 15356 defines the "decisionmaking body" as "any person or group of people within a public agency permitted by law to approve or disapprove the project at issue," and Section 15378(a)(3) defines the project as "an activity involving the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies." In this instance, the Project is the construction by Phillips 66 of the tank that requires the issuance of a permit by the District.

2. The Executive Officer is the Final Decisionmaking Authority for the Issuance of a Permit to Operate.

The Executive Officer is the person "permitted by law" to approve or disapprove the air permit application for the Project, and is therefore the "decisionmaking body" who must make CEQA determinations associated with air permit applications.

California Health and Safety Code §42300(a) states:

> "Every district board may establish by regulation, a permit system that requires, except as otherwise provided in Section 42310, that before any person builds, erects, alters, replaces, operates, or uses any article, machine, equipment, or other contrivance which may cause the issuance of air contaminants, the person obtain a permit to do so from the air pollution control officer of the district."

Pursuant with this authority, in 1976 the District Governing Board adopted a series of rules in Regulation II providing for the issuance of permits by the Executive Officer. District Rule 201 currently states, in pertinent part:

> "A person shall not build, erect, install, alter or replace any equipment or agricultural permit unit, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer."

And Rule 203(a) currently provides:

> "A person shall not operate or use any equipment or agricultural permit unit, the use of which may cause the issuance of air contaminants, or the use of which may reduce or control the issuance of air contaminants, without first obtaining a written permit to operate from the Executive Officer or except as provided in Rule 202."

Therefore, in accordance with the Health and Safety Code and District Rules, the Executive Officer is the final authority for the issuance of permits, and thus the decisionmaking authority for permitting project approvals.[5] This determination was previously upheld in Los Angeles Superior Court in 1994, when the court found that the Executive Officer was the proper decisionmaking authority for a permit approval and thus for the CEQA determination.[6]

3. There Is No Avenue of Appeal to the District Governing Board through CEQA Guidelines Section 15074(f).

CBE's appeal petition asserts that the District's Governing Board is the highest-elected decisionmaking authority for the agency and therefore the Board must hear an appeal of the Executive Officer's CEQA determination. However, CEQA Guidelines Section 15074(f), relied upon by CBE, does not apply to the Governing Board.

Section 15074(f) provides:

> "When a non-elected official or decisionmaking body of a local lead agency adopts a negative declaration or mitigated negative declaration, that adoption may be appealed to the agency's elected decisionmaking body, if one exists. For example, adoption of a negative declaration for a project by a city's planning commission may be appealed to the city council."

This provision does not create an avenue to appeal to the Governing Board. As demonstrated above, the Governing Board is not the decisionmaking body of the District with respect to permit decisions. In addition, the Governing Board is not an elected body. The composition of the District Governing Board is described in Health and Safety Code Section 40420. This section directs that the District "shall be governed by a district board consisting of 13 members ***appointed as follows...*"** The following eight paragraphs itemize the entities who have the power to appoint Governing Board members. In some but not all cases, the appointees must be elected officials in a different capacity (e.g., elected to a city council or county board of supervisors), but all members of the Governing Board obtained that position through appointment, not election.

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[5] Note that the District's Regulation XII allows any person to petition the Governing Board to hold a hearing on a permit application. The decision to hold such a hearing on an application is entirely discretionary on the part of the Governing Board; there is no right on the part of a petitioner to have such a hearing. However, in this case the permit has already been granted and there is no open application. Thus, the time to petition the Governing Board to hold such a hearing has passed.

[6] See, *Atwood v. South Coast Air Quality Management District* (1994), Case No. BC093076: The "decision-making body" is the person permitted by law to approve or disapprove the project. CEQA Guidelines Section 15356. By District Rule, this person is Dr. Lentz[sic], the Executive Officer. As such, it would appear that Dr. Lentz[sic] would be the person to review and consider the final EIR. (Tentative Ruling, Section III entitled "Consideration and Certification of the EIR"). Attached hereto as Exhibit 4.

B. The Executive Officer Properly Determined That a Negative Declaration Should be Prepared for the Project.

CBE alleges that the Executive Officer violated CEQA by failing to prepare an Environmental Impact Report (EIR) for the Project. However, based on all of the evidence presented in the whole of the record a Negative Declaration was the proper CEQA documentation to be prepared.

CEQA requires that if a lead agency determines that a proposed project would not have a significant effect on the environment than the agency <u>shall</u> adopt a negative declaration.[7] The District conducted a thorough and conservative analysis of the potential impacts of the project and found that there would not be any significant impacts. Furthermore, notwithstanding the reduction in waiting time during which ships are anchored and emitting just offshore, the District did not consider any reduction in ship emissions that would result from the Project, adding yet another conservative factor.

While CBE provided many pages of comments and opined that the project may have a significant impact on the environment, the District properly concluded that none of CBE's information amounted to substantial evidence of a significant impact. Preparation of an EIR is required whenever <u>substantial evidence</u> in the record supports a fair argument that significant impacts may occur. There is no such substantial evidence here.

CEQA defines "substantial evidence" as "fact, a reasonable assumption predicated upon fact, or expert opinion supported by fact. Substantial evidence is not argument, speculation, unsubstantiated opinion or narrative, evidence that is clearly inaccurate or erroneous, or evidence of social or economic impacts that do not contribute to, or are not caused by, physical impacts on the environment."[8] As explained in the Responses to Comments in the Final Negative Declaration, much of the information provided by CBE is not relevant to the Project It consists of general statements regarding refining operations that are not applicable to the Project, is predicated upon

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[7] California Public Resources Code §21080(c).

[8] California Public Resources Code §21080(e).

incorrect assumptions, or constitutes unsupported opinion. Hence, these comments did not provide substantial evidence of a significant impact, and the Executive Officer correctly approved the Negative Declaration.

C. CBE has not Provided Any Basis for Reconsideration of the Negative Declaration Approval Either by the Executive Officer or the Governing Board

In addition to alleging that the Executive Officer was not the final decisionmaking authority for the District, addressed above, CBE further alleges that Negative Declaration for the Project should immediately be withdrawn because the information provided by the Executive Officer in the Responses to Comments in the Final Negative Declaration was new and in itself required additional public review. Also, CBE provides additional information, not previously submitted to the District, to support its contention that the Project description was inadequate and that the Project will have a significant impact on the environment. Contrary to CBE's contentions, neither the information provided by the Executive Officer in the Responses to Comments nor the additional information submitted by CBE to the Governing Board provide substantial evidence of a new avoidable significant impact.

1. The information provided in the Responses to Comments did not Require Recirculation Before Adoption.

CEQA Guidelines Section 15073.5 requires a lead agency to recirculate a negative declaration, "when the document must be substantially revised after public notice of its availability has been previously been given pursuant to Section 15072, but prior to its adoption." Under this section, "substantial revision" means "a new, avoidable significant effect is identified and mitigation measures or project revisions must be added in order to reduce the effect to insignificance." This section also states that, "recirculation is not required when new information is added to the negative declaration which merely clarifies, amplifies, or makes insignificant modification to the negative declaration."

The Executive Officer provided information in the Responses to Comments that clarified the scope of the Project, explained why certain information provided by CBE was not relevant to the Project or was inaccurate, and corrected many of the misunderstandings CBE appear to have regarding Project impacts. None of the new information identified a "new, avoidable significant impact" and therefore it did not constitute a substantial revision requiring recirculation. Hence, the approval of the Negative Declaration was proper.

2. CBE's Appeal to the Governing Board Does not provide substantial evidence of any significant impacts.

Attached to the Petition for Appeal, CBE included several documents in an attempt to bolster its argument that the approved Negative Declaration did not accurately and completely describe the Project or analyze the impacts of the Project, in particular, alleged changes in crude quality. However, the information attached to the appeal is not new, is not relevant to this project, and more importantly, does not provide substantial evidence of a new significant impact from the Project that would require reconsideration of the Negative Declaration approval.

Under CEQA, only three conditions require additional review after a Negative Declaration has been approved[9]: (1) where substantial changes are proposed to the Project that will require major revisions to the document to address a new significant impact or a substantial increase in an already significant impact; (2) where substantial changes to the circumstances of the project will require major revisions to address a new significant impact or a substantial increase in an already significant impact: or (3) where new information of substantial importance, which could not have been known with reasonable diligence at the time of adoption, demonstrates the project will have new significant effects not discussed, or more severe than previously determined.[10] None of these circumstances exist here. There have been no changes to the Project. The information provided by CBE does not demonstrate a change in the project, its circumstances or impact, and there is no "new information of substantial importance" that CBE has provided demonstrating new impacts. In fact, the "new" evidence is merely a rehashing of its previous comments.

As in the comments submitted during the public review period for the Negative Declaration, CBE again alleges that corporate statements support the conclusion that the project scope is inadequate. As "evidence" of this conclusion, CBE references a Phillips 66 investor

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[9] This occurs only where an additional discretionary action is pending. However, in this case, there is none.

[10] CEQA Guidelines§ 15162(a)

statement entitled "2014 Fact Book,"[11] that contains, among much additional information, a statement that: "[w]e are adding additional tankage at our Los Angeles Refinery to increase access to advantaged waterborne crudes." CBE also includes a statement from the transcript of an investor conference call from the third quarter of 2014[12], where the Phillips 66 Chairman and CEO is quoted as stating that the company will "get to 100% advantaged crude in the next year." Finally, CBE references a map in a Phillips 66 slide presentation entitled *Investing, Building, Growing – Phillips 66 Investor Update, Third Quarter 2014,* ("Investor Update Presentation")[13]. These three sentences, each taken out of context, are stitched together to purportedly support the conclusion that Phillips 66 intends to increase the use of Bakken and Canadian tar sands crude oil as feed to the Refinery, and this, in turn, will have a significant impact on the environment.

These three sentences do not constitute "new" evidence for several reasons. CBE made exactly the same argument and proffered nearly identical "evidence" in its comments on the Negative Declaration during the public comment period. *See*, for example, Comments 2-3 and 2-15 in the final Negative Declaration.[14] As part of those earlier comments, CBE included nearly identical statements taken from Phillips 66 investor documents telling investors that the company plans to increase the use of "advantaged crudes" in the coming years. CBE incorrectly concludes, both in the Negative Declaration comment period and now, that the company's statements regarding "advantaged crudes" means that the Los Angeles Refinery will increase the use of two particular types of crude, Bakken and Canadian tar sands crude.

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[11] Exhibit L to CBE's petition for Appeal

[12] Exhibit I was withdrawn from the Exhibits submitted by CBE with the Appeal

[13] Exhibit J to CBE's petition for Appeal

[14] Comment 2-3 states: "Additionally, Phillips 66's Project description is incomplete, filing to identify that the proposed changes to the refinery inputs to the crude unit, including expanded use of the brine stripper and the added heat exchangers, which are exactly the increased desalting and temperature controls needed to enable processing of cheaper "Advantaged Crude" which Phillips 66 has publically announced it is bringing by rail and ship to California, including to the Los Angeles refinery."
And see Comment 2-15:"Phillips 66 showed in its Annual Report business plans emphasizing new use of 'Advantaged Crudes', in other words, cheaper unconventional crude oils including Canadian tar sands crude, and Bakken Crude (from the Dakotas) and to bring them to West Coast refineries, including the Los Angeles refinery by rail, as well as by marine vessel, as explained by the accompanying legal comments, and as shown in the report's map and statements below." (Reference to Phillips 66, 2012 Summary Annual Report.)

While some Phillips 66 United States refineries may increase the use of these crudes in the future, the Project does not cause or facilitate doing so at the Los Angeles Refinery. "Advantaged crude," as used by Phillips 66, generally means economically advantaged and does not refer to a particular type of crude. *See*, Declaration of Darin Fields attached hereto as Exhibit 1 at 7: "[a]s this term is used by Phillips 66, this term simply means that the cost of the crude is less than the cost of the benchmark Brent crude." Additionally, the Los Angeles Refinery is already operating at essentially 100% advantaged crudes. Declaration of Darin Fields at 17. Therefore, the Project will not increase the use of advantaged crude at the Los Angeles Refinery.

In addition, as in its comments on the Negative Declaration, CBE misinterprets Phillips 66 statements regarding advantaged crude. Advantaged crudes are selected from among the crudes that are otherwise appropriate for and available to a particular refinery. Phillips 66 considers a number of factors in selecting crude oil for the Refinery. The factors include whether a particular crude is compatible with the design of the refinery, either alone or when blended with other crudes, and whether it can be refined to yield the product slate desired for that refinery's market, while adhering to Phillips 66's mission of operating safely, reliably, and in compliance with environmental laws. Declaration of Darin Fields at 8. As explained in the Responses to Comments in the final Negative Declaration, heavy Canadian crudes, including tar sands crudes, are currently being blended and run at the Refinery. In fact, they have been run at the Los Angeles Refinery for nearly 15 years.

CBE references a graphic in the Phillips 66 "Investor Update Presentation" broadly depicting transportation routes in the United States. Without the narrative that accompanied the presentation, this slide cannot be interpreted accurately. It is an over-simplified depiction of possible options for moving crude by rail to the various Phillips 66 refineries. It was not meant to depict actual or planned movement of Bakken crude to the Los Angeles Refinery by marine vessel. *See*, Declaration of Ryan Caillier, attached hereto as Exhibit 2.

Additionally, Bakken crude, while currently advantaged for other refineries in the Phillips 66 refinery network, is not advantaged for the Los Angeles Refinery when delivered by marine vessel. See, Declaration of Maureen McCabe, attached hereto as Exhibit 3, at 12. And significant technical difficulties and restrictions associated with transporting Bakken by marine vessel, make it infeasible to deliver it the Los Angeles Refinery via marine vessel. Declaration of Maureen McCabe at 10-11. Thus, the processing of Bakken is not a foreseeable consequence of the installation of this Project. Declaration of Maureen McCabe at 14.

Further, the Project will not have an effect on the delivery of Canadian heavy crudes to the Los Angeles Refinery. Currently, the Refinery receives the heavy Canadian crudes in partially loaded Aframax tankers. The tankers are partially loaded due to water depth and other constraints at the facility where the crude is loaded. The tankers that deliver the heavy Canadian crudes can be offloaded in one vessel call. Therefore, the addition to the Refinery of a larger tank will not impact the delivery of the heavy Canadian crudes, including tar sands crudes.

The final Negative Declaration repeatedly, consistently and correctly states that the Project is not about bringing Bakken crude oil and Canadian heavy crude oil to the Los Angeles Refinery. In the Appeal Petition, CBE tries again to drown the District in extraneous information to create the impression that it is. If there was any remaining ambiguity on this point, it is dispelled by the Fields, Caillier and McCabe declarations, which further corroborate the facts upon which the Executive Officer approved the Negative Declaration and issued the permits.

CBE's Appeal Petition conveys additional exhibits that are not relevant to the Project. For instance, reports and comments on other projects around the state do not provide relevant information regarding the Project at hand. Reports on the accidents at other facilities, on rail safety and general overviews of general impacts of refining, and comments on other Refinery projects do not provide facts specific to the Project that could be considered evidence of significant impacts as a result of the Project.

Finally, even if the information submitted with CBE's petition was "new," the majority of the information could easily have been submitted to the District before the Negative Declaration was approved. Nearly all was available <u>months</u> before the document was approved. However, CBE made no attempt to submit the information into the record. Note that in its January 2, 2015 letter to District staff requesting the Executive Officer withdraw the Negative Declaration (attached to the CBE petition as Exhibit R) CBE states that it contacted staff periodically to request updates on the review and approval of the document on several occasions in 2014 after the close of comment period, including on February 4, March 20, July18, August 8, September 11, October 7 and November 5.

Therefore, CBE knew that it had ample opportunity to submit the information to the District for consideration prior to approval of the Negative Declaration.

III.
CONCLUSION

Because the Executive Officer, as the final decisionmaking authority for the issuance of permits, properly reviewed and considered all of the evidence in the whole of the record, determined that there was no substantial evidence of a significant effect on the environment and approved the Negative Declaration in accordance with CEQA, and review of the decision would in this instance be improper, the appeal by CBE should be denied.

Dated: January 29, 2015

Respectfully submitted,

By: ______________________

Frances L. Keeler
Jocelyn D. Thompson
Attorneys for Project Proponent and Respondent
Phillips 66 Los Angeles Refinery

EXHIBIT 1

DECLARATION OF DARIN L. FIELDS

I, Darin L. Fields, declare:

1. I am the Refinery Manager for the Phillips 66 Company ("Phillips 66") Los Angeles Refinery. I make this declaration in support of Phillips 66's opposition to the *Appeal of Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project* filed by Communities for a Better Environment ("CBE Appeal"). I have personal knowledge of the facts set forth in this declaration and if called as a witness, I could and would testify competently to them.

2. I have been the Refinery Manager for the Phillips 66 Los Angeles Refinery since February 1, 2014. Prior to becoming Refinery Manager of the Los Angeles Refinery, I was the Operations Manager of the Phillips 66 Sweeny Refinery in Old Ocean, Texas.

3. Altogether, I have been employed by Phillips 66 and its predecessors (including ConocoPhillips Company and Phillips Petroleum Company) for 26 years. Fifteen of these years, I have held management positions.

4. The Los Angeles Refinery includes the Wilmington Plant, the Carson Plant, and a marine products terminal at Berths 148-151 in the Port of Los Angeles.

5. As Refinery Manager of the Los Angeles Refinery, my responsibilities include the profit/loss performance of the Los Angeles Refinery, along with all aspects of refinery operations. I am familiar with the equipment and operations of the Los Angeles Refinery, including the crude oil and other raw materials and intermediate products procured for the refinery, and the products and co-products produced by the refinery. Crude oil selection has a substantial influence on the performance of the refinery.

6. As a member of the Refinery management team, I participate in management decisions relating to the Los Angeles Refinery. I am familiar with the business objectives established by the company. I am responsible for implementation of corporate objectives that are relevant to the operation of the Los Angeles Refinery.

7. Currently, one of the objectives set by corporate management is to use what the company refers to as "advantaged crude." As this term is used by Phillips 66, this term simply

means that the cost of the crude is less than the cost of the benchmark Brent crude. For example, in presenting the company's progress in shifting to advantaged crude in 2012, Phillips 66 management explained, "[w]e're trying to displace Brent price crudes out of our systems ... and ultimately get to 90% of our total crude based on something other than Brent price." (Phillips 66 First Annual Analyst Meeting, December 13, 2012, edited transcript, p. 13, found at Final Negative Declaration, Appendix F, Exhibit R; see also Exhibit U.)

8. The objective of running advantaged crude oil is only one of many factors to be considered in selecting the crude oils for a particular refinery. The paramount considerations in selecting crude oils are whether they are compatible with the design of the refinery, either alone or when blended with other crudes, and whether they can be refined to yield the product slate desired for that refinery's market, while adhering to our mission of operating safely, reliably, and in compliance with environmental laws. For a particular refinery, advantaged crudes are selected from among the range of crudes compatible with the design and desired product slate for that refinery, and that can feasibly be delivered to that refinery.

9. Depending upon the circumstances, cost-advantaged crude oils for any particular refinery in the United States may include, among others, heavy crude oil from Canada and South America, light crude oil produced from shale formations such as the Bakken in North Dakota and the Eagle Ford in Texas (see 2012 Summary Annual Report, Final Negative Declaration, Appendix F, Exhibit D, p.8); crude from the Mississippian Lime formation in Kansas and Oklahoma (see 2012 Summary Annual Report, p. 24, found at Final Negative Declaration, Appendix F, Exhibit D); and Heavy Louisiana Sweet, Louisiana Light Sour, and Alaska North Slope (see Q4 2013 Phillips 66 Earnings Conference Call, January 29, 2014, edited transcript, p.4, excerpts from which are attached as Exhibit 1 to my declaration). Whether a particular crude is considered advantaged varies by refinery and can change from time to time.

10. As further described in the Declaration of Maureen McCabe, crude oil can also be presented at an advantaged price because of unexpected events. We call these "distressed crudes," and they are also considered advantaged crudes.

11. The cost comparison for determining whether a crude is advantaged is based

on the "landed" price at a particular location. As management has stated: "[W]e define advantaged as crudes that land at our refineries at a discount to landed Brent." (See Phillips 66 Analyst Meeting, April 10, 2014, edited transcript, p. 12, excerpts from which are attached as Exhibit 2 to my declaration.) The landed price includes the per barrel purchase price of the crude oil as well as transportation costs and other costs.

12. Transportation costs vary significantly depending upon the mode of transportation, e.g., truck, pipeline, train, marine vessel, barge or some combination of these. Within a given mode of transportation, the transportation cost may be affected by distance, by equipment availability, or potentially by constraints along the route. For example, it generally costs more per barrel to transport crude oil by rail from the Midwest to California than it does to transport the same crude oil to the East Coast.

13. Phillips 66 operates 11 refineries located in the United States. Because the cost comparison for determining an advantaged crude is based on the landed price for a refinery, there is wide variation among the refineries as to which crudes are considered advantaged.

14. For example, when I was the Operations Manager at the Sweeny Refinery, we considered crude oil from the Eagle Ford shale in Texas to be advantaged, among others. As described further in the Declaration of Maureen McCabe, Bakken crude oil may be considered an advantaged crude for some Phillips 66 refineries; however, Bakken crude oil delivered by marine vessel is not considered an advantaged crude for the Los Angeles Refinery due to substantial logistical obstacles.

15. Across the company, the Phillips 66 refineries operated at approximately 95% advantaged crude oil in the third quarter of 2014. (See Phillips 66 Investor Update, Third Quarter 2014, p. 24, found at CBE Appeal Petition, Exhibit J.)

16. The Crude Oil Storage Capacity Project at the Los Angeles Refinery will allow larger marine vessels (e.g., Suezmax) to unload their entire cargo in one ship call. This will improve the efficiency of our unloading process and avoid demurrage incurred while a ship waits for us to move enough crude oil out of our tanks to be able to receive the remainder of the vessel's cargo. In 2014 alone, the company incurred nearly $4 million in demurrage costs associated with the

need for larger vessels to unload in two ship calls, and the delay between the unloading events.

17. The Crude Oil Storage Capacity Project will not cause the Los Angeles Refinery to refine more advantaged crude because the refinery already runs nearly 100% advantaged crudes. However, by improving the efficiency of vessel unloading and avoiding demurrage, the Project will allow the Los Angeles Refinery's landed crude costs to compare even more favorably to benchmark Brent crude oil. For this reason, the Project can be said to increase the refinery's access to advantaged waterborne crudes.

18. In the appeal petition to the South Coast Air Quality Management District Governing Board, Communities for a Better Environment ("CBE") asserts that the Project will cause an increase in the amount of Canadian tar sands crude oil and Bakken crude oil refined at the Los Angeles Refinery. CBE's assertions rely on a misreading of corporate statements. CBE interprets the Phillips 66 term "advantaged crude" to mean Canadian tar sands crude and Bakken crude. As demonstrated in paragraphs 7 through 14, above, this is not correct.

19. Using the company's definition, Bakken crude may be considered advantaged at some Phillips 66 refineries in the United States, but Bakken crude delivered by marine vessel is not considered advantaged for the Los Angeles Refinery due to substantial logistical obstacles and the high cost of transportation, and the Project will not change this.

20. Canadian heavy crudes, including what CBE calls "tar sands" crude, are currently considered moderately advantaged at the Los Angeles Refinery, but they will not be affected by the Project because they are not transported to the refinery using the Suezmax and larger vessels that currently must unload in two ship calls, as described further in the Declaration of Maureen McCabe.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 29 day of January, 2015, in Los Angeles, California.

Darin L. Fields

DARIN L. FIELDS

EXHIBIT 1

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

PSX - Q4 2013 Phillips 66 Earnings Conference Call

EVENT DATE/TIME: JANUARY 29, 2014 / 05:00PM GMT

CORPORATE PARTICIPANTS

Clayton Reasor *Phillips 66 - SVP-IR, Strategy and Corp Affairs*

Greg Garland *Phillips 66 - Chairman and CEO*

Greg Maxwell *Phillips 66 - CFO*

Tim Taylor *Phillips 66 - EVP*

CONFERENCE CALL PARTICIPANTS

Douglas Terreson *ISI Group - Analyst*

Evan Calio *Morgan Stanley - Analyst*

Jeff Dietert *Simmons & Company International - Analyst*

Edward Westlake *Credit Suisse - Analyst*

Paul Cheng *Barclays Capital - Analyst*

Doug Leggate *BofA Merrill Lynch - Analyst*

Roger Read *Wells Fargo Securities, LLC - Analyst*

PRESENTATION

Operator

Welcome to the fourth quarter 2013 Phillips 66 earnings conference call. My name is Shannon, and I will be your operator for today's call.

(Operator Instructions)

Please note that this conference is being recorded. I will now turn the call over to Mr. Clayton Reasor, Senior Vice President, Investor Relations, Strategy and Corporate Affairs. Mr. Reasor, you may begin.

Clayton Reasor *- **Phillips 66 - SVP-IR, Strategy and Corp Affairs***

Thank you. Good morning. Welcome to Phillips 66 fourth quarter earnings conference call. With me this morning are Greg Garland, our Chairman and CEO; our CFO, Greg Maxwell and EVP, Tim Taylor. The presentation material we will be using can be found on the IR section of the Phillips 66 website, along with the supplemental, financial and operating information.

Slide 2 contains our Safe Harbor statement. It is a reminder that we will be making forward-looking comments during the presentation, and our Q&A session. Actual results may differ materially from today's comments, and factors that could cause these results to differ are included here on the second page of the presentation, as well as in our filings with the SEC.

So that said, I will turn the call over to Greg Garland for some opening remarks. Greg?

Greg Garland *- **Phillips 66 - Chairman and CEO***

Thanks, Clayton. Good morning, everyone. Thanks for being with us today.

We ended 2013 with a solid quarter. We operated well. It allowed us to capitalize on favorable crude differentials, while exporting record volumes of refined products. Our adjusted earnings for the quarter were $800 million, and our cash flow from operations excluding working capital was $1.3 billion.

Slide 5 provides a comparison of our fourth quarter adjusted earnings with the third quarter, looking at it on a segment basis. Compared to last quarter, our earnings increase were largely driven by improved results in refining. Partially offsetting this, are lower earnings from marketing and specialties, as well as midstream. I will cover each of these segments in more detail later on.

The Midstream segment posted lower earnings this quarter, as higher earnings from NGL Operations were more than offset by lower earnings from DCP. The 2013 adjusted return on capital employed from midstream was 15%, and this is based on an average capital employed of $3.2 billion.

Slide 7 shows Midstream's fourth quarter earnings of $121 million, a decrease of $27 million from last quarter. Transportation made $50 million this quarter, which is pretty much in line with last quarter. However, compared to last year this business line is up significantly, as results now reflect market rates.

DCP Midstream's earnings decreased by $50 million, primarily due to lower equity gains resulting from DPM unit issuances to the public, and along with lower volumes mainly due to adverse weather impacts. NGL operations and other were up, primarily due to inventory and higher propane margins and sales. On the next slide, we will cover -- we will move onto a discussion of our chemical segment.

In Chemicals, olefins and polyolefins ran well, with a global capacity utilization of 95% for the quarter. In addition, the SA&S business successfully completed a planned major turnaround of its benzene unit located in Pascagoula, Mississippi. The 2013 return on capital employed from our Chemicals segment was 26%, and this is based on an average capital employed of $3.8 billion.

As shown on slide 9, fourth quarter earnings for chemicals were relatively flat, compared to last quarter coming in at $261 million. In olefins and polyolefins, earnings were up mainly due to higher volumes, and increased equity earnings from its Saudi Polymers Company joint venture. Lower earnings from specialties, aromatic's and styrenic's more than offset this improvement, as a result of lower production and the cost impacts associated with the planned benzene turnaround in the fourth quarter.

Moving on to Refining. Our realized margin was $10.75 per barrel, with a market capture rate of 112%. The global crude utilization rate was 92%, and our clean product yield was 84%.

During the quarter, 94% of the Company's US crude slate was advantaged, and this compares with 66% last quarter. The increase was largely driven by additional domestic crude's consistently trading at a discount to Brent. We will cover this in more detail on slide 13. The 2013 adjusted return on capital employed for refining was 13%, and the average capital employed for this segment was $14.3 billion.

Slide 11 provides more detail on Refining earnings improvements in the fourth quarter. The Refining segment had earnings of $450 million, and this is up from a loss of $2 million last quarter. This increase is mainly due to higher realized margins, in spite of market cracks dropping an average of 28% worldwide.

In the Gulf Coast, margins improved largely due to product differentials, as exports and blending activities helped us realize better clean product prices. We also benefited from the fact that the distillate crack increased nearly 30% in the fourth quarter. The increase in the central corridor was largely driven by the widening of Canadian differentials, as well as improvements due to butane blending into the gasoline pool.

Western Pacific's improvement is mainly due to improved clean product yields, product differentials, and also secondary product values. For the Atlantic Basin, this region was down due to the impact of lower market cracks, as well as Bayway having a major scheduled turnaround during the fourth quarter. Other refining was down this quarter due to scheduled maintenance on the Keystone pipeline. All available pipeline capacity was used to deliver crude to our refineries, however, a lack of surplus capacity prevented us from capturing additional gains.

Next let's look at our market capture on slide 12. Compared to the market, our realized margin improved mainly from feedstock opportunities, most notably in the central corridor. In addition, secondary products were less of a negative impact this quarter, reducing the margin by $5.54 a barrel, compared with $6.35 last quarter.

As captured in the other bar, we also benefited from clean product differentials. During the quarter, we realized better prices on average for clean products, compared with the benchmark prices. In addition, as RIN prices moderated, the benefit of resulting lower expenses is reflected in this bar.

Slide 13 shows the comparison of advantage crude runs at our US refineries by quarter, for 2013 on the left, and for the past three years, as shown on the graph on the right. During the quarter, 94% of the Company's US crude slate was considered advantaged, and this compares with 66% last quarter. The 28 percentage point increase reflects the inclusion of other light and medium crude's which have been trading consistently at a discount to Brent. Some examples include HLS, LLS, and ANS.

On an annual basis, our advantaged crude slate has increased from 62% in 2012, to 74% in 2013. And this is due to processing an additional 118,000 barrels per day of tight oil, additional domestic crude's that consistently trade at a discount to Brent, as well as higher volumes of heavy Canadian crudes. The decrease in other heavy crude category from 27% in 2012, to 24% in 2013 is attributable mainly to downtime at our Lake Charles and Sweeny refineries this year.

Operator

Our next question comes from Doug Leggate from Bank of America Merrill Lynch.

Doug Leggate - ***BofA Merrill Lynch - Analyst***

Thanks, good morning, or good afternoon, everybody. In your presentation, you obviously talked about the change in definition, I guess of how you see advantaged crudes. What was -- I just want to get a little more detail on that. Are you saying basically that you are -- you have changed the definition, which means you are no longer pursuing a more aggressive change in the slate? Or are you still expecting to have some substitution within that newly-defined 94%? And I have got a couple follow-ups, please?

Tim Taylor - ***Phillips 66 - EVP***

Okay. Doug, the definition really -- it is not definitional. It is just the fact that these -- particularly the Gulf Coast crudes and ANS have consistently traded in the fourth quarter at a significant discount to Brent. And I think that is a part of our crude slate -- we have always said that we expected those crudes to discount, and when they did, they would turn to advantaged.

That said, we continue to work on logistic solutions, particularly to the East and the West Coast and to the Gulf Coast. And we are very active in finding ways to substitute one advantaged crude for another, particularly with options that we see in the Permian and Mid-Con for crudes that deliver more value to our refining operations. So it is a very active area for us, both in terms of light, medium and heavy crudes, and the logistics and the operating optimization that we go through.

Doug Leggate - ***BofA Merrill Lynch - Analyst***

I guess what I am trying to understand is that, was it a proactive -- there wasn't a proactive change in the slate? It was really more to what the market gave you that pushed you up to 94%? Is that the right way of thinking about it?

Clayton Reasor - ***Phillips 66 - SVP-IR, Strategy and Corp Affairs***

I think that, generally, that is probably right. I think that, we, in the past we had not included LLS or HLS, or ANS for that matter, in advantaged crudes because it was trading at Brent or better. And what we are saying is, given that we -- products are priced off of Brent, and we think that will continue, that if the crudes are pricing at -- consistently at a discount to Brent, then we should consider those considered -- or consider those advantaged. Now I don't think it says that we are any less aggressive about substituting higher discounted crudes. But your point is correct, in that the market is the primary reason why we are considering LLS or HLS or ANS advantaged at this point.

Doug Leggate - ***BofA Merrill Lynch - Analyst***

Thanks Clayton. That is very clear. If I could just get two quick follow-ups, please? I don't hold a lot of hope in this one, but any chance you can give us a breakdown between Bayway and Europe, in terms of the split of earnings in the quarter, or the loss in the quarter?

Clayton Reasor - ***Phillips 66 - SVP-IR, Strategy and Corp Affairs***

There -- you are right. There is no chance on that one. (Laughter).

Doug Leggate - ***BofA Merrill Lynch - Analyst***

Okay. And the last one for me is really more of a kind of big picture issue. And I guess, Greg, you have been quite vocal about your support for crude exports, in contrast to some of your refining peers. I wonder if you can just give us a quick kind of summary as to why you are taking that view? And I will leave it there, thanks.

EXHIBIT 2

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

PSX - Phillips 66 Analyst Meeting

EVENT DATE/TIME: APRIL 10, 2014 / 06:30PM GMT

CORPORATE PARTICIPANTS

Clayton Reasor *Phillips 66 - SVP of IR, Strategy & Corporate Affairs*

Greg Garland *Phillips 66 - Chairman and CEO*

Tim Taylor *Phillips 66 - EVP of Commercial, Marketing, Transportation & Business Development*

Greg Maxwell *Phillips 66 - EVP of Finance and CFO*

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Doug Leggate *BofA Merrill Lynch - Analyst*

Ed Westlake *Credit Suisse - Analyst*

Paul Cheng *Barclays - Analyst*

Blake Fernandez *Howard Weil Incorporated - Analyst*

Paul Sankey *Wolfe Research - Analyst*

Evan Calio *Morgan Stanley - Analyst*

Faisel Khan *Citigroup - Analyst*

Roger Read *Wells Fargo Securities - Analyst*

Jeremy Tonet *JPMorgan - Analyst*

PRESENTATION

Clayton Reasor - ***Phillips 66 - SVP of IR, Strategy & Corporate Affairs***

Good afternoon, and welcome to the Phillips 66 2014 analyst meeting. And on behalf of the entire management team of Phillips 66, let me express our thanks to those of you here in the room and those listening on the webcast. We appreciate your interest in our Company and hope you find the next couple hours of interest. My name is Clayton Reasor; I have responsibility for investor relations at Phillips 66.

In 2012, a new Company was formed. A Company with leading midstream; a global chemicals and integrated refining, marketing and transportation business. A Company that was constructed in a way to allow it to capitalize on the remarkable growth in domestically produced oil, natural gas, and shale NGLs. And over the last two years, Phillips 66 has been able to translate this production growth into strong earnings and cash flows.

We operated well; we increased our financial flexibility; created a great place to work for our employees, while being a good neighbor in the communities we operate in. And our share price reflects this performance.

But we are not here today to talk about our past or tell you what a good job we have done. Rather, we want to talk about our future. We plan to use the next two hours to share our plans for creating sustainable shareholder value with new specifics on growth, returns, distributions, and capital allocation.

We will have three speakers today, with our Chairman and CEO leading off. Greg Garland will discuss how the realization of our vision and execution of our strategy will create differentiated returns for our shareholders. Next up will be Phillips 66 Executive Vice President Tim Taylor, and Tim will provide new information about our exciting midstream growth plans and what is driving capital efficiency in refining. Greg Maxwell, our CFO, will provide an update on financial plans, an important topic given the value of maintaining a strong balance sheet in a business as cyclical as ours. Immediately following our CEO, Greg Garland, we'll come back to the podium and lead a Q&A session.

As part of our presentation and in response to your questions, we will be making forward-looking statements. Actual results may differ materially from the comments we make today, and factors that could cause those results to differ can be found on page 3 of this presentation, as well as in our filings with the SEC.

So this is what we told you in December of 2012 that we wanted to accomplish in 2013. We checked the boxes. We are delivering on both the financial and the operating results. We IPO'd our MLP, Phillips 66 Partners. Chevron Phillips Chemical Company is advancing the first world-scale petrochemical complex we built on the US Gulf Coast in more than a decade.

When you think about our returns in refining, we've improved those by putting advantaged crudes to the front of the refineries. We exited last year at about a 90% advantaged crude rate. This reflects not only a market shift in crudes versus Brent but also our ability to put advantaged crudes to the front of the refineries.

We told you were going to acquire 2,000 railcars. We have done that. They are in service. Tim is going to tell you later today, we are in the process of acquiring another 1,200 cars.

We signed significant third-party agreements to load and unload advantaged crude. We will be able to extend our capabilities in advantaged crude, and we will highlight some of those today. We returned over $6 billion of capital to shareholders since May of 2012. At the same time, we've reshaped and reinvested in our portfolio.

We've increased dividends from $0.80 annually to $1.56. And as I said, we took in about 10% of the shares of the Company.

We also said that in 2012 and 2013 we were going to repay $2 billion of debt. We have done that, so we strengthened our balance sheet capability and our flexibility.

So as we think about the strategic drivers for our strategy, the underlying businesses of our Company have been around for more than 100 years. As you know, external environment has undergone significant recent change. Growing natural gas, natural gas liquids, crude oil production is reshaping our industry. We've gone from a period of extended resource constraint to volume production -- one of abundance and growing production.

We think US refining has a structural price advantage and energy cost advantage. It's going to allow us as an industry to effectively meet domestic demand and also compete for growing share of export markets. We think that global demand that's spurred by growth in developing countries like China, India, Brazil will grow more than 1 million barrels a day annually.

We think that investors will continue to place a higher multiple on businesses that have stable cash flows and significant growth potential. So refining is a significant source of cash for us, but it was, it is, and always will be a very volatile business. So part of our rationale for shifting the portfolio to more midstream and chemicals is the expectation for more stable cash flow and higher valuations. We also believe that the uplift from natural gas to natural gas liquids to petrochemicals is more durable and more sustaining than the value uplift from crude to refined products.

Move on and talk just a couple macro slides if I can. Here's midstream. These are our expectations for midstream growth. 2010, over 2 million barrels a day. We think by the end of the decade, between 3 million and 5 million barrels a day of natural gas liquids production. This is creating tremendous investment opportunities in the industry for gathering, processing NGL fractionation; LPG export. We think the industry will invest between $100 billion and $150 billion in new infrastructure.

We continue to think that expanding in US petrochemicals makes sense. By the end of the decade, we see between 600,000 and 1 million barrels a day of new ethane in the US. We think the US is going to be a competitively advantaged place to make petrochemicals. In fact, we think it's the best place in the world to make petrochemical investments today.

Fundamentally, we believe that our olefins and polyolefins chain, because of this global leading technology position and global leading market position and the fact that we have concentration of assets in the Middle East and North America, this asset will continue to be the highest-returning asset in our portfolio, and it's one we want to grow.

Moving on to the refining macro environment. You can see significant growth in crude coming from Canada, Texas, and North Dakota. This production is going to displace crudes that have historically been imported in the US. By the end of this decade, we expect to have displaced most of the light and medium sweet crudes and a majority of the other crudes. We think this translates into advantages for US refining and good margins for the industry.

So we understand the risks that are inherent in our business; we are experienced at managing these risks. We have proven ourselves capable of managing complex mega-projects in our industry. For example, our Wood River Coker refinery expansion, we call it the CORE project -- $4 billion, on time, on budget, flawless start-up, well-executed project.

DCP is a very experienced project manager. Two big pipes: Sand Hills, Southern Hills. About $1 billion each. On time; on budget; well-executed project. CPChem, very capable project manager. The past 12 to 14 years, five mega-projects in the Middle East. As you think about that environment, very complex, very competitive environment; not unlike the environment we're going to face on the US Gulf Coast in the next five to seven years. Well-executed projects.

Speaking about the dock itself, we have the -- this dock will have the capability to load eight VLGC carriers -- or cargoes of propane and butane each month. That's about 150,000 barrels a day.

We have the capability to expand that by an additional four cargoes to make that a much more significant asset, and we are currently in conceptual development to expand the concept now to include condensate splitting in the area and to include other NGL fractionators.

So we are laying the groundwork for a much larger and involved and more purposeful NGL business that's based on the asset footprint that we have at Sweeny. So we are excited about that, and it's a major step in our growth program for the Midstream business at Phillips 66.

I want to talk about our transportation business in some detail. We get quite a bit of questions about that, and I think this lays the groundwork for its size and scale and opportunity it has, particularly as it ties back to PSXP, our MLP.

So, when you talk about transportation, again, we are talking about crude oil logistics, we're talking about our rail assets, we're talking about Jones Act ships that we move to get crudes to our markets, and then, we're talking about increasing export capability.

Overall, this segment generated about $400 million of EBITDA in 2013. We project that would be about $500 million in 2014. You can see that we are ramping up the capital spending as we capture these opportunities, talking about doubling it to about $400 million of opportunity space there as we look at ways to continue to increase our connectivity, expand our pipeline system, and add services to our terminals to capture the opportunities that we see in the marketplace.

I got four maps here to talk about our main operating regions and talk about the assets that we have and the opportunity set that we have. A really critical area for us where we have a significant amount of transportation infrastructure is in the Midcon region, right in the heart of the [century]. We've got three Phillips 66 operating refineries in this region. It's a very significant part of our operation, and the pipeline system plays a very important role both in delivering crudes to the refineries, as well as moving products to markets, and we're a long way from some of the markets, so it's a critical piece getting value in this particular system.

The Gold pipeline we will talk about a bit later, but that was recently acquired by PSXP to show you how that begins to fit with our overall Midstream strategy.

I think the interesting thing about the Midcon for us, even though we've got 3,700 miles of pipeline here, is that it's coincident with what's happening in the oil and gas development in the area, and given our asset footprint, because of our history here, we've got a lot of right-of-way, a lot of pipelines that allow us to look at options to bring new crudes into our system, but also provide market access for other producers and opportunities to do that. So it's a very active area for development that we are currently working on many projects to expand our presence and the opportunity set there.

The second point I'd make is that in this system, we also include Explorer Pipeline, which runs from the Gulf Coast. It's a product pipeline that runs from the Gulf Coast to Chicago, and we recently increased our ownership interest in the last quarter by 6% to 19.5% in that pipeline system. It is one of the major product pipelines in the US.

The story and the transportation system in the Rockies is very similar to the Midcon. We've got a great asset base in terms of pipelines, but a relatively small refining presence with our 60,000-barrel a day Billings Refinery. But we deliver crudes, primarily Canadian crudes, into Billings via the Glacier Pipeline that we jointly owned with Plains.

And then we distribute the products east -- or excuse me, west and south out of Billings into markets in the upper Rockies, eastern Washington, and now increasingly -- increasing connection to the south to markets in Salt Lake, and even having access now with the UNEV Pipeline to Las Vegas.

So it's an area that is fairly small, but taken together, our transportation system, our refining business, and the marketing opportunities that we have in this area, this is one of our most profitable regions and it's one that we continue to find ways to invest and grow because it is a very valuable piece of our portfolio.

As I look at the west coast, we have a relatively small footprint in the west coast in terms of pipelines, about 600 miles of pipe. Most of that is really directed toward crude that we access in central California and then move to Los Angeles or Rodeo refineries or Santa Maria Refinery there.

We have about 100 miles of product pipe in that system, as well. We also have some very high-volume terminals. But I think the real story in the transportation section on the west coast, it's really about our rail connectivity, so we are currently in the process of completing a 30,000-barrel a day rail rack to unload crudes at our Ferndale, Washington, refinery and we're in the permitting process for a 20,000-barrel a day rack at Santa Maria, and we hope to see that one advance soon.

We expect Ferndale to be operational later this year, and on top of that, we are continuing to find ways to do third-party unloading to increase crude supply to the west as well, and we just recently signed a deal with Plains in Bakersfield, California, to put Canadian crudes into that pipeline system for delivery to our refining system.

So we are continuing to find ways to get new crude sources, particularly inland crudes, into the west coast and improve its competitive position, but that is a key function and key driver and focus for us on the west coast in transportation.

The final region that I wanted to show in some detail is the Gulf Coast, and again, it's not a huge system in terms of our own pipelines, but it's a very active area, a number of large systems there that connect to that, and the dynamics of this region are changing rapidly. You've got a lot of new crude sources pushing in from the Permian, from Cushing, coming into the Gulf Coast, and there have been a number of bottlenecks now developed to getting that crude to the refining system on the Gulf Coast or to other parts of the refining system in the US.

And so, we've been very active, increasing our connections and our capability to get those crudes into our refining system and to provide access to docks and other ways to get the crude into the system. In fact, in this area, we do run MR tankers across from Corpus to our refining system in Louisiana and occasionally to Bayway to capture that, and I think you'll continue to see those solutions develop and you'll continue to see opportunities for new pipelines, particularly on the crude oil/natural gas liquids side, to keep those products moving to markets and the refining centers on the Gulf Coast.

So I have touched on this a little bit, but I don't think any discussion on transportation today in the US when you think about the crude side of our business would be complete without a discussion around rail and marine. And this map shows a more comprehensive view of how we are servicing the needs for our refineries and supplementing that from what's traditionally been either marine oceangoing supply or pipeline supply.

So, we have a very active program to move south Texas crudes along the Gulf Coast with two MR-class tankers. We have 14 barges that are currently in crude service. We have 42 others in different services, and we have the ability to flex that barge capacity between crude and other services, so we have an opportunity to continue increase our delivery with that.

We are also now going to be able to load crude out of our Freeport dock, where we used to receive it by barge out of south Texas, so it's freeing up some capacity and opportunities for that.

We have been very active in the rail space. To do this, we talked about the rail rack at Bayway that comes up later this year. We've got a 70,000-barrel a day rail rack that will be coming up this quarter at our Bayway refinery, so taken together, we've put 100,000 barrels a day of additional rail and loading capacity for us on the east and the west coast, and to supplement that, we are continuing to grow our third-party connections to bring even more crude into the system, and we talked about Bakersfield in terms of unloading in California. Though also on the sourcing side, we developed new agreements recently in the past several months at Hardisty, Alberta, which lets us access heavy Canadian crudes, Berthold, North Dakota, for Bakken, and then at Casper, Wyoming, we've also got capacity there, which would allow us to bring crudes into California or other parts of our refining system from there.

So we are continuing to progress that, and I think rail will continue to be a piece of the solution for us. So Greg mentioned our fleet started out at 2,000 new railcars we took delivery of in 2013. We will take -- we will put 1,200 more cars in service in 2014, and in terms of capacity, that means that the 2,000 cars that delivered about 100,000 barrels a day, the 3,200 cars will increase that capability to 160,000 barrels a day.

So on top of that, we've got additional third-party commitments that let us really flex that rail system, and we ultimately see rail probably being 5% to 10% of our crude supply in North America because the pipeline capacity just isn't there to make that happen.

So, I think before I leave and talk about DCP and the Midstream, I think this is a slide that we've been anxious to show everybody because it really says what's the impact of all the growth projects that we are talking about in our Midstream business.

So last year, in 2013, we had $0.5 billion of EBITDA in the Midstream business. And we're going to grow that to $1.5 billion in 2017 with the projects that we just talked about and the opportunities. Half of that comes from the Sweeny NGL hub; a quarter comes from operations that are currently embedded in refineries, such as storage, docks, and terminal assets; and another quarter will come through additional transportation growth in our pipeline and terminal system. These are all very solid projects, so we are talking about a tripling of our Midstream EBITDA, and I think that really speaks to the opportunity that we see to grow the Midstream business in both Phillips 66, but just as importantly to grow for Phillips 66 Partners, our MLP.

So we currently own 73% of PSXP as a limited partner and we own the 2% GP as well. We have talked about top quartile distribution growth for that. It's important to have that backlog of EBITDA and the project backlog to drive that.

The real challenge for us is to continue to increase that connectivity to some of our light processing refineries on the east and the west coast, hence the comments around rail and the logistics solutions that we look for to do that. But overall, we think we're in great shape to take advantage of the changing crude supplies -- crude slate in North America through our system.

We talked in 2012 at the analyst meeting about a $500 million improvement in refining and refining net income on a constant margin basis. We're delivering on that. We continue to make that progress.

In this chart, you can see about half of that improvement will come from increased runs of advantaged crudes. About a quarter -- or the other half will come from yields improvements, as well as increased exports, and overall when you look at our asset base today, our five-year average on refining return has been about 11%. We see that growing by 4 percentage points to about 15%. So continuing to see stronger business in our base refining business and taking steps to really work that, and I'll talk in more detail about some of those.

The biggest piece of that, of course, is how do we get lower-priced, higher-value crudes in the front end of our refinery? It's the number one competitive advantage that we have, and we spend a lot of time between our commercial, refining, transportation groups to drive that.

We've talked a bit about our light oil capability or heavy oil capability. We talked about the rail system that will increase the connectivity and the supply of that. Those are all actions that we have taken, and the result has been that we've increased our utilization of advantaged crudes from 62% in 2012 to 74% in 2013, and so far this year, we have average 90% advantaged crude.

And part of that is the fact is how you define advantaged, and for simplicity, we define advantaged as crudes that land at our refineries at a discount to landed Brent. So, the big change for us in North America has been the relative discounting of LLS and ANS as these inland crudes have now made it to the places where refiners didn't have those options in the past and those crudes have begun to discount.

So a significant change there and one that we think will be enduring. They will certainly move around, but I think the increased supply and competition has changed that and made that a bigger part of what we do.

The other thing that we like to do with crude is we like to gather local crude, very consistent quality, high value at our refineries, so crude-on-crude substitution, even within light tight oil, is important to us, and we also like to make sure that we have the capability to have options in our waterborne refineries that have access to waterborne crudes that we can maintain the optionality on those as well. So, we'll continue to evolve that.

I would say that finally on advantaged crude, the real issue today is logistics. It's about how to get those crudes out of the central part of the US and put more of that into the east and the west coast, hence why we work on that so much in our organization.

Just a couple of comments on yields. We have talked about this in the past. We have an industry-leading distillate yield of 40% today. The industry average is 37%. We see that going to 41% through optimization of our operations.

We are continuing to look at ways to increase our clean product yield, so we see that increasing from 84% to 85%, and that's really driven off of two things -- increased recovery of LPGs where we burn those as fuel today in some refineries, and then increasing conversions on some of our lower-valued fractions in our key operating units, like FCCs or hydrocrackers, where we get to convert at a higher percentage those low-valued fractions into higher-valued fractions. Overall, a one-point change in clean product yield yields about $100 million in net income for the refining business.

The export story, Greg touched on this, but it's just a great story for us. We have increased our export capacity and our export shipments substantially over the last two years, and we did that without spending a lot of capital. It really came through a concerted organizational effort between commercial and refining to find ways to optimize dock space and remove constraints and meet product specs that met export specifications.

And we have now revised our estimates of what our capability for exports will be. We see that growing from just over 400,000 barrels a day at 2013 to over 550,000 barrels a day in 2016, and most of that change comes in the Gulf Coast. And at 550,000 barrels a day, 25% of our US output could be exported and 42% of our US coastal refining capacity could be exported, and we think that's critically important as the US continues to have high crude runs, relatively flat product demand, and this is an opportunity to take that length and supply markets, particularly in the Atlantic Basin, with increased product supply out of the US that's very competitive. So we feel there's strong market pull for this, as well as strong operating push behind that part of the export business.

EXHIBIT 2

DECLARATION OF RYAN P. CAILLIER

I, Ryan P. Caillier, declare:

1. I am employed by Phillips 66 Company ("Phillips 66"), and I provide this declaration in support of Phillips 66's opposition to the *Appeal of Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project* filed by Communities for a Better Environment ("CBE Appeal"). I have personal knowledge of the facts set forth in this declaration and if called as a witness, I could and would testify competently to them.

2. I am an analyst in the Phillips 66 Investor Relations Group. I have held this position for approximately one year. Prior to joining the Investor Relations Group, I was an analyst in the company's Treasury organization and its Commercial organization. The latter is the corporate group responsible for buying and selling crude oil, other feedstocks, and products. Altogether, I have been employed by Phillips 66 and its predecessors (including ConocoPhillips Company) for approximately three years.

3. In my current position in the Investor Relations Group I support the Manager and the Vice President of Investor Relations by, among other things, preparing slides and other materials for presentations and other communications with investors, potential investors, financial analysts and others.

4. I have reviewed Exhibit J to the CBE Appeal petition. Exhibit J is set of presentation slides entitled *Investing, Building, Growing – Phillips 66 Investor Update, Third Quarter 2014,* ("Investor Update Presentation"). I assisted in preparation of this presentation, and I am the author of Slide 11.

5. By their very nature, presentation slides are incomplete communication. They serve as a backdrop as the speaker orally communicates with the audience. The speaker communicates the primary message, including context and narrative, and the slide plays a supporting role.

6. Slide 11, entitled Transportation – West and East Coast, depicts a variety of Phillips 66 transportation components on the east and west coasts of the United States. My primary purpose in preparing this slide was to identify options for moving crude oil by rail, including the

location of Phillips 66 refineries in relation to the rail network and the location of facilities where Phillips 66 had access through commercial agreements. The slide presents a generalized view of potential options for discussion purposes; it does not present information regarding transportation routes that were then in use or that the company intended to use.

7. Slide 11 shows a rail connection from Berthold, ND to a commercial agreement location in Oregon, and an arrow indicating waterborne options from there to Phillips 66 refineries in Ferndale, Rodeo and Los Angeles. At the time I prepared the slide, I was aware that Phillips 66 was capable, through a commercial relationship, of loading crude oil onto barges. I was aware that this route had been used to deliver crude oil to the Ferndale and Rodeo refineries via barge. I was not aware of any shipments via barge or marine vessel from Oregon to the Los Angeles Refinery, nor was I aware of any plan for the company to do so. The Declaration of Maureen McCabe, filed concurrently herewith, describes the limitations on any such shipments.

8. Slide 11 in the Investor Update Presentation originated in an earlier presentation entitled *Investing, Building, Growing – Phillips 66 2014 Analyst Meeting, April 10, 2014* ("Analyst Meeting Presentation"), excerpts from which are attached as Exhibit 1 to my declaration. I assisted in the preparation of the Analyst Meeting Presentation.

9. Slide 33 in the Analyst Meeting Presentation, which I also authored, contains the same graphic as Slide 11 in the Investor Update Presentation. In addition, Slide 33 contains text that further explains the graphic. As the text shows, the graphic was intended to provide general information on rail and marine transportation. The text notes 14 crude barges, which correspond to the barges used to transport crude oil on inland and coastal waters in the United States to certain Phillips 66 refineries, including the Ferndale and Rodeo refineries. The text also notes two Jones Act ships, and these ships correspond to the red arrows emanating from Corpus Christi, Texas to Phillips 66 refineries elsewhere along the Gulf Coast and the Bayway Refinery in New Jersey.

10. Slide 33 in the Analyst Meeting Presentation summarize slides 29 through 32, which discussed transportation in four regions of the United States. Slide 31 pertains to the West Coast Region. Slide 31 does not identify marine routes for transporting inland crude to West Coast terminals. At the April 10, 2014 Analyst Meeting, Slides 29 through 33 were presented by Mr. Tim

Taylor, then Executive Vice President of Commercial, Marketing, Transportation and Business Development. With respect to Slide 31, Mr. Taylor discussed pipeline assets and then emphasized rail connectivity; he did not mention marine transportation to the West Coast. (See Phillips 66 Analyst Meeting, April 10, 2014, edited transcript, which is Exhibit 2 to the Declaration of Mr. Darin Fields, filed concurrently herewith, at p. 8-9.)

I declare under penalty of perjury under the laws of the State of Texas that the foregoing is true and correct.

Executed this 29 day of January, 2015, in Houston, Texas.

Ryan Caillier

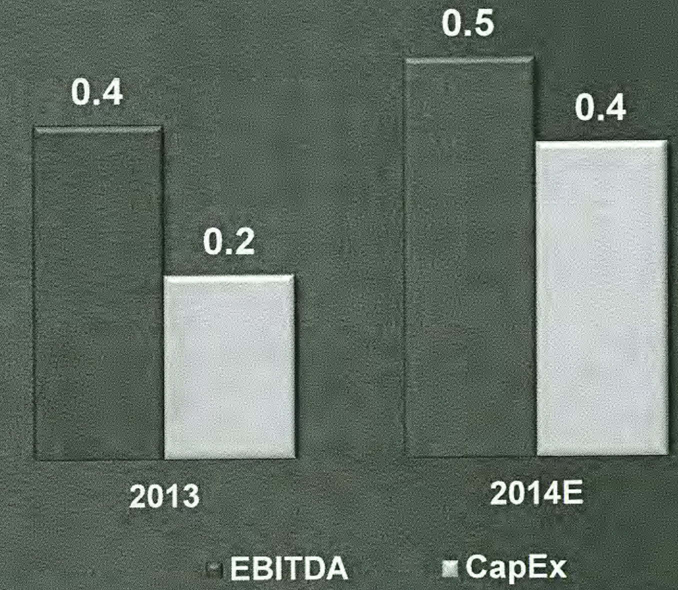
RYAN P. CAILLIER

EXHIBIT 1

Investing
Building
Growing
66A
66A
66C
66F
66I
B
PHILLIPS 66
2014 Analyst Meeting
April 10, 2014
New York, N.Y.

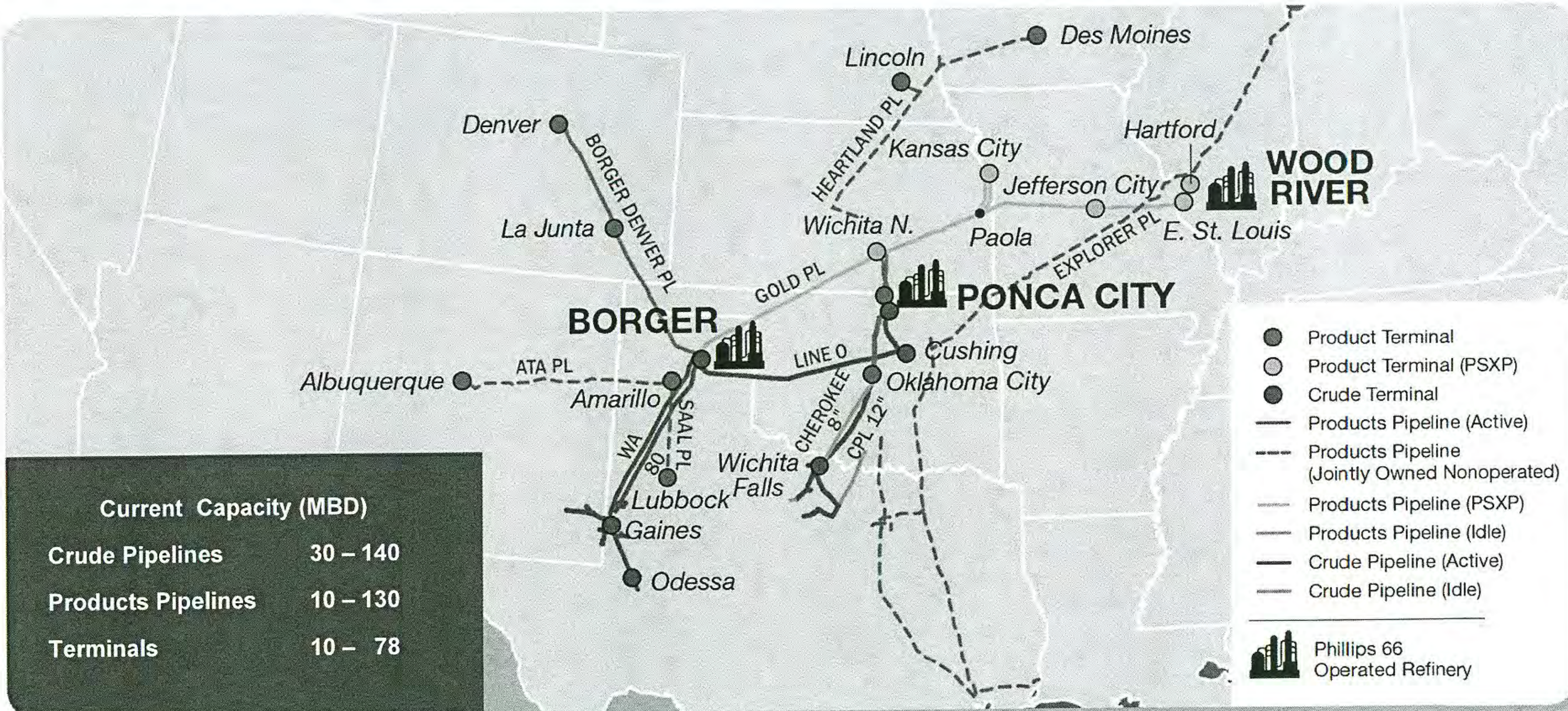
Transportation

- Crude oil logistics
- Rail cars
- Jones Act ships
- Refined product exports



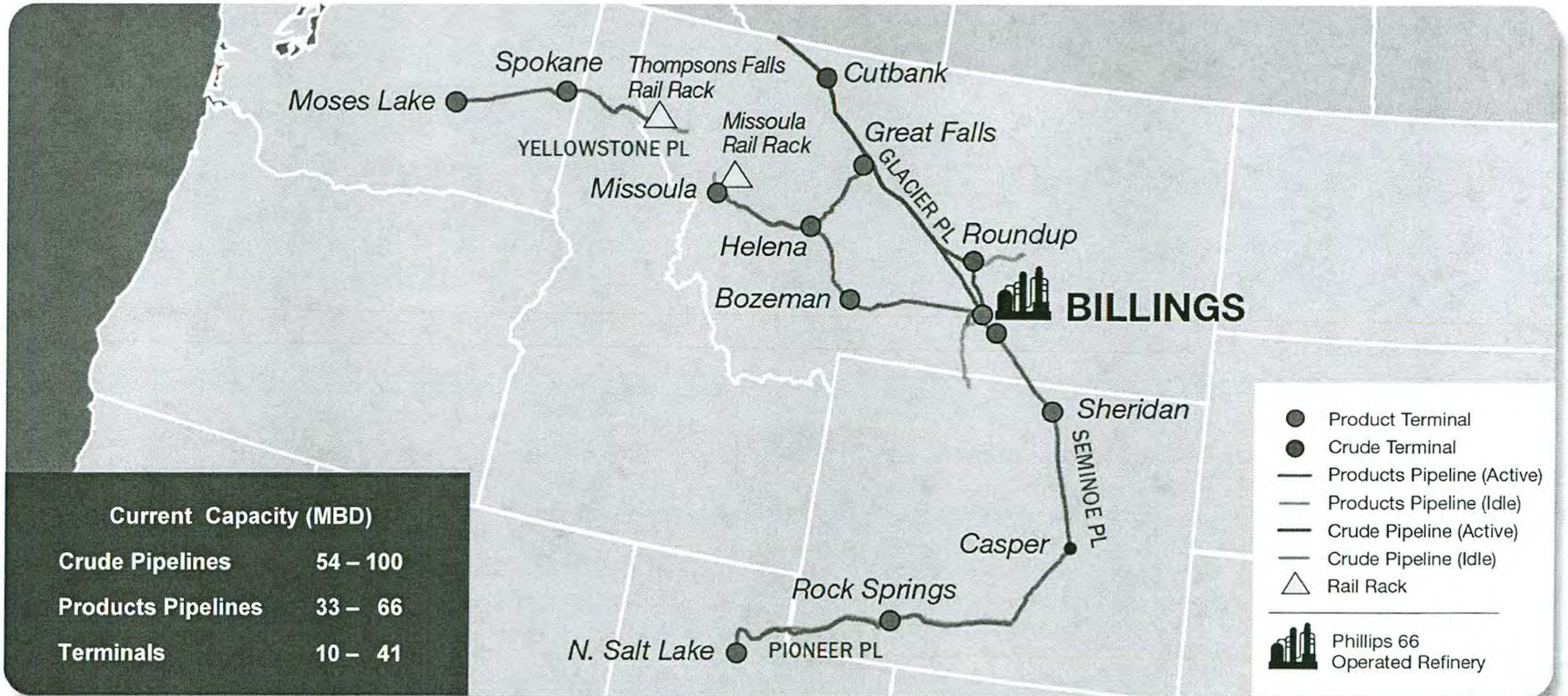
Transportation EBITDA includes noncontrolling interests.

Transportation – Midcon Region



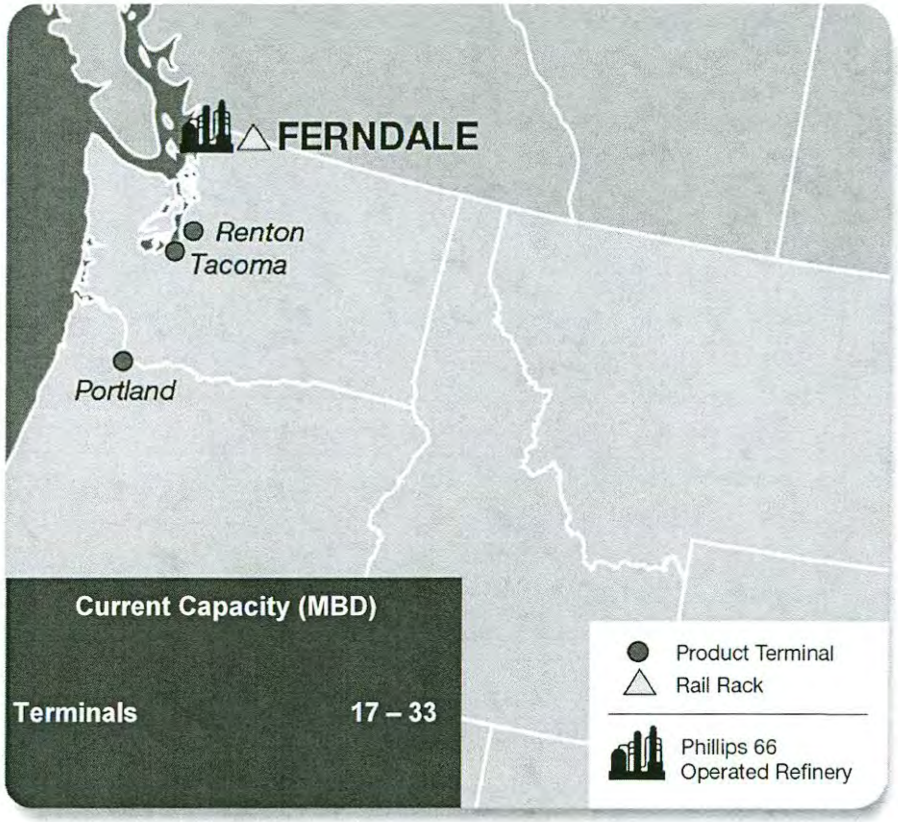
Current Capacity (MBD)	
Crude Pipelines	30 – 140
Products Pipelines	10 – 130
Terminals	10 – 78

Transportation – Rockies Region

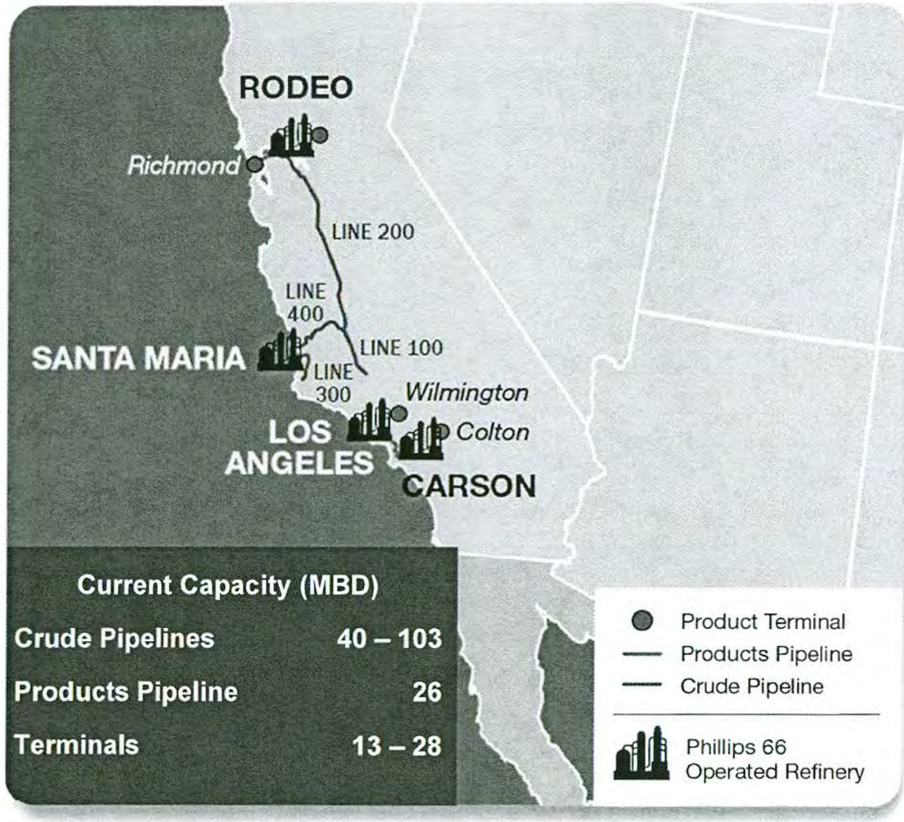


Current Capacity (MBD)	
Crude Pipelines	54 – 100
Products Pipelines	33 – 66
Terminals	10 – 41

Transportation – West Coast Region

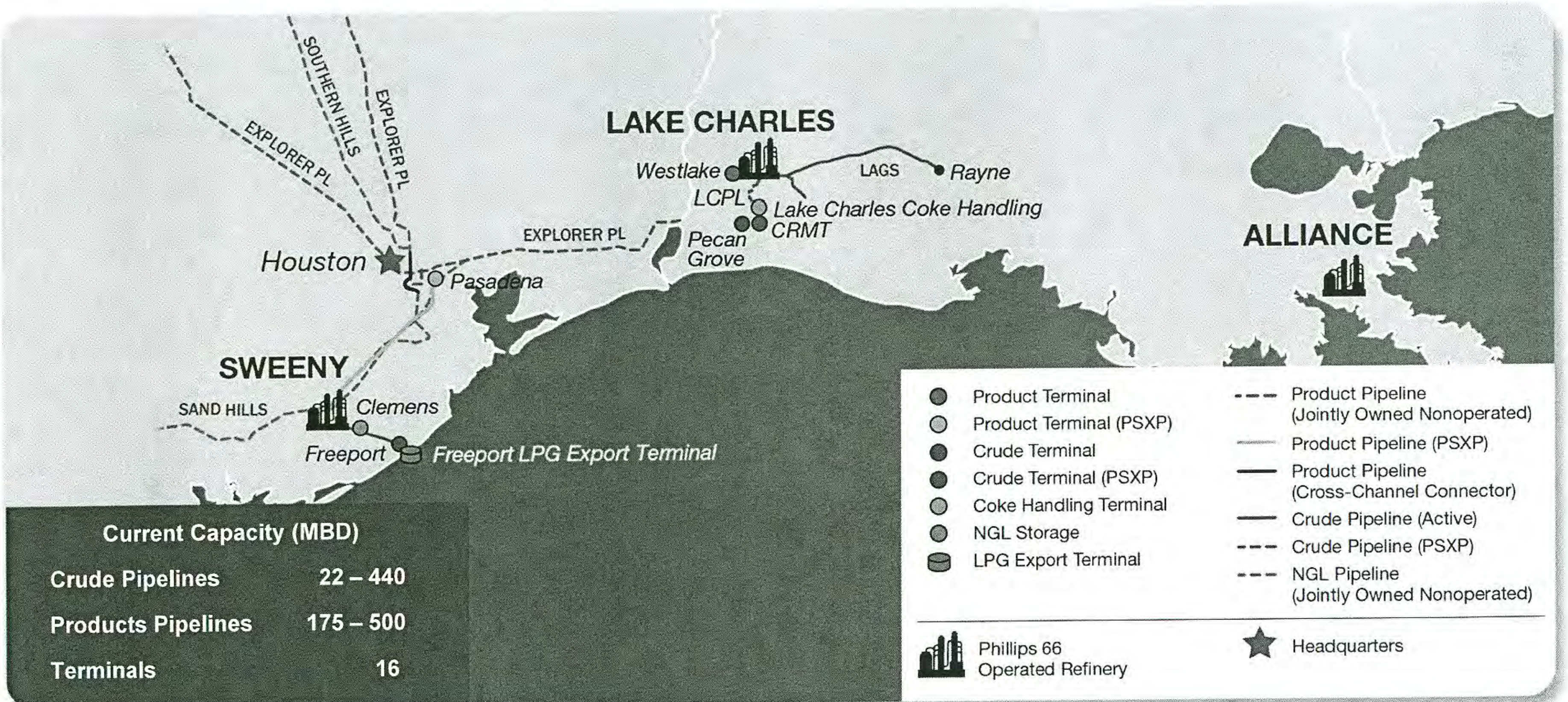


Current Capacity (MBD)	
Terminals	17 – 33



Current Capacity (MBD)	
Crude Pipelines	40 – 103
Products Pipeline	26
Terminals	13 – 28

Transportation – Gulf Coast Region



Current Capacity (MBD)	
Crude Pipelines	22 – 440
Products Pipelines	175 – 500
Terminals	16

Transportation – Rail and Marine

Enhancing logistics optionality

- 2 Jones Act ships
- 14 crude barges
- Freeport crude loading

Increasing crude rail capability

- 5 rail unloading facilities
- 1,200 additional rail cars

See appendix for footnotes.

EXHIBIT 3

DECLARATION OF MAUREEN McCABE

I, Maureen McCabe, declare:

1. I am the West Coast Domestic Crude Trader for Phillips 66 Company ("Phillips 66"). I make this declaration in support of the Phillips 66 opposition to the *Appeal of Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project* filed by Communities for a Better Environment ("CBE Appeal"). I have personal knowledge of the facts set forth in this declaration and if called as a witness, I could and would testify competently to them.

2. I have held the position of West Coast Domestic Crude Trader since 2008. Altogether, I have been employed by Phillips 66 and its predecessors (including ConocoPhillips Company and Conoco Inc.) for over seventeen years. Eleven of these years, I have been involved in crude trading, procurement, or delivery.

3. In my current position, my responsibilities include purchasing crude and optimizing crude supply for the Phillips 66 West Coast refineries. I am familiar with the equipment and operations of the Los Angeles Refinery as they affect my responsibilities for procurement of crude oil and other feedstocks.

4. Selection of crude for a refinery involves a number of factors. The crude must be compatible with the refining equipment and configuration, either alone or as blended with other crudes, to ensure that the crude can be refined by the refinery in question safely, reliably, and in compliance with environmental and other laws. The crude should present the highest value relative to other available crudes considering the crude characteristics, the refinery configuration, and the products the refinery intends to produce. It also must be feasible to deliver the crude to the refinery utilizing available transportation networks.

5. Cost also is a factor in selecting crude. Currently, one corporate objective is to refine what the company refers to as "advantaged crude." As described in more detail in the Declaration of Darin Fields, advantaged crude means crude that costs less than benchmark Brent crude. For a particular refinery, advantaged crudes are selected from among the range of crudes compatible with the design and desired product slate for that refinery, and that can feasibly be

delivered to the refinery.

6. The cost comparison for determining whether a crude is advantaged is based on the "landed" price at a particular location. The per barrel acquisition price of the crude and transportation costs usually make up the majority of the landed cost of a crude.

7. Transportation costs vary significantly depending upon the mode of transportation, e.g., truck, pipeline, train, marine vessel, barge or some combination of these. Transportation costs are also affected by distance, by equipment availability, or potentially by constraints along the route. For example, it generally costs more per barrel to transport crude oil by rail from the Midwest to California than it does to transport the same crude oil to the East Coast.

8. On occasion, a shipment of crude oil is considered advantaged because unexpected events cause the crude to be offered at a discount. For example, if another company purchases crude oil but then suffers an unexpected breakdown and cannot receive it, we are sometimes able to negotiate purchase on favorable terms due to the distressed circumstances. We call these "distressed crudes." It is impossible to forecast where distressed crudes will originate, because the price advantage is unrelated to the factors that usually affect price.

9. The Los Angeles Refinery currently refines essentially 100% advantaged crude. Over the past 10 years, the majority of the crude processed at the Los Angeles Refinery has originated in the United States, Canada, Ecuador and Iraq. (See Final Negative Declaration p. F-46.) The table below compares the estimated landed costs of crudes representative of the crudes we run from those countries to a published posted price for Brent crude. If a landed price were used for Brent crude, the table would show that the cost advantage of the other listed crudes is greater.

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L.A. Crude Pricing vs. Brent, $/BBL	2011	2012	2013	2014
Brent (1)	110.85	111.64	108.67	99.56
CA Midway Sunset (2)	104.52	104.93	102.57	91.72
Ecuador Oriente (3)	103.78	103.60	99.10	91.03
Iraq Basrah Light (4)	108.96	108.19	103.69	95.76
Canadian Heavy (5)	97.45	92.51	92.75	89.71
Bakken (delivered by water) (6)	N/F	N/F	N/F	N/F

Price Differential vs. Brent, $/BBL				
CA Midway Sunset	(6.33)	(6.72)	(6.10)	(7.84)
Ecuador Oriente	(7.07)	(8.04)	(9.57)	(8.53)
Iraq Basrah Light	(1.88)	(3.45)	(4.97)	(3.80)
Canadian Heavy	(13.39)	(19.13)	(15.92)	(9.85)
Bakken (delivered by water)	N/F	N/F	N/F	N/F

Notes:

1. Argus Ice Brent
2. CA Postings for MWSS; plus $1.70/bbl Plains pipeline tariff & 0.10% loss allowance
3. Argus Oriente Month, FOB pricing + $3.65/bbl marine transportation & dock fees (2011 - May 2014) (Platts FOB June 2014 - forward)
4. Argus Basrah Trade Month, FOB pricing + OSP + estimated freight
5. Published Western Canadian Select @ Edmonton + pipeline tariffs + premium fees (4Q14 assumes same PL Premium as 3Q2014) to Westridge dock + estimated marine freight
6. N/F = Not Feasible

10. Bakken crude oil may be considered an advantaged crude for some Phillips 66 refineries, but Bakken crude oil transported via marine vessel is not currently considered an advantaged crude for receipt at the Los Angeles Refinery. As explained in Paragraphs 4, 5 and 6, advantaged crudes are selected from among the crudes compatible with the design and desired product slate for the refinery in question, and that can feasibly be delivered to the refinery. The Los Angeles Refinery does not receive Bakken crude by marine vessel, and it is not feasible to do so.

11. Hypothetical routing of Bakken crude to Los Angeles via marine transport would require the crude to first be shipped via rail from North Dakota to the Pacific Northwest, transferred to a barge or marine vessel, and shipped south to Los Angeles. There are multiple logistical obstacles to doing this. Phillips 66 cannot load crude oil in the Pacific Northwest onto vessels that can be unloaded in the Los Angeles area. Phillips 66's Ferndale Refinery has a rail rack and a marine terminal, but it does not have authority to transship crude oil received at its rail

terminal out through its marine terminal. Phillips 66 is not aware of any transload facility in the area capable of loading crude from rail onto anything other than barges or potentially marine tanker vessels classified as "MR," which are smaller than Panamax sized ships. In Southern California, Phillips 66 has a commercial arrangement to receive crude at Berth 121 in the Port of Long Beach. (Berths 148-151 in the Port of Los Angeles are considered part of the Los Angeles Refinery, but this is not a crude terminal.) Berth 121 is not designed to receive either barges or ships smaller than Panamax, and there is no proposal to modify the terminal in order to do so. Therefore, a barge or MR vessel loaded with Bakken crude in the Northwest would have to reverse lighter its cargo to a Panamax or larger sized ship in order to offload at Berth 121. The logistical obstacles make this routing for Bakken crude impractical, and the multiple transshipments would add substantial costs.

12. Bakken crude does not compare favorably with advantaged crudes currently run at the Los Angeles Refinery, and the added cost of a hypothetical marine transportation route would exacerbate the disadvantage of refining Bakken crude in Los Angeles.

13. The Crude Oil Storage Capacity Project will not make it feasible to transport Bakken crude to Los Angeles via Berth 121 because it will not remove the logistical obstacles described in Paragraph 11.

14. The Crude Oil Storage Capacity Project will not facilitate transport of Bakken crude to the Los Angeles Refinery. As noted, facilities in the Pacific Northwest are capable of loading crude onto barges and small marine tanker vessels. Even if Phillips 66 could receive these vessels in Southern California, the Project does nothing to facilitate it. The Project involves construction of a larger storage tank to enable larger ships to offload in a single ship call. The existing tanks would be able to receive the full cargo of a barge or a small marine tanker without modifications to the equipment or the permits. Therefore, the Project does nothing to facilitate delivery of Bakken crude to Los Angeles.

15. Canadian heavy crudes, including what CBE calls "tar sands" crude, are currently refined at the Los Angeles Refinery and are considered advantaged. The Crude Oil Storage Capacity Project will not cause an increase in the amount of Canadian heavy crude delivered to Los Angeles. Canadian heavy crude is not transported to the refinery using the Suezmax and

larger vessels that currently must unload in two ship calls.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this ___ day of January, 2015, in Los Angeles, California.

Maureen McCabe

EXHIBIT 4

RECEIVED
OCT 21 1994
RVB

ORIGINAL FILED
OCT 19 1994
LOS ANGELES
SUPERIOR COURT

SUPERIOR COURT OF THE STATE OF CALIFORNIA

COUNTY OF LOS ANGELES

RALPH ATTWOOD, JR., ROBERT W. JOHNSTON, and UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPE FITTING INDUSTRY OF THE UNITED STATES AND CANADA, LOCAL UNION NO. 250, Petitioners and Plaintiffs, vs. SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT, Respondent and Defendant, CHEVRON U.S.A. PRODUCTS COMPANY, Real Party in Interest.	Case No. BC093076 [[redacted]] ORDER

This matter came on regularly for hearing before the Court, the Honorable Diane Wayne, Presiding, on August 2, 1994. Thomas R. Adams and Ann Broadwell appeared as attorneys for Petitioners. William B. Wong and Frances L.

Kesler appeared as attorneys for Respondent, the South Coast Air Quality Management District. Ronald E. Van Buskirk and Betsy G. Stauffer appeared as attorneys for Real Party in Interest, Chevron U.S.A. Products Company. Gail Feuer and Everett DeLano appeared as attorneys for *amici curiae* Natural Resources Defense Council and Citizens for a Better Environment.

The Court, having issued its written Tentative Ruling, copy attached hereto, and having reviewed and considered the record, the evidence and arguments set forth in the papers submitted by counsel, and having heard and considered the oral argument of counsel at the hearing, enters the following order:

1. For the reasons given in the Tentative Ruling, the matter is remanded to Respondent to set aside its certification of the Environmental Impact Report (EIR) and for further proceedings in accordance with CEQA and the Court's Ruling to clarify who is to certify the EIR, and who (or what entity) is to review and consider the EIR, as well as who is to adopt the findings, statement of overriding considerations and the mitigation monitoring plan for the Chevron project.

2. Respondent shall serve and file a return evidencing its compliance with this Order by October 11, 1994.

3. Ongoing project construction and operations under permits previously issued by Respondent are permitted to continue pending Respondent's return to this Court.

IT IS SO ORDERED.

Dated: ________________.

____
The Honorable Diane Wayne
Judge of the Superior Court

Approved as to form:

PILLSBURY MADISON & SUTRO
Ronald E. Van Buskirk
Betsy G. Stauffer

By ______________________________

Attorneys for
Real Party in Interest

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
William B. Wong
Frances L. Keeler

By ______________________________

Attorneys for Respondent

ADAMS & BROADWELL
Thomas R. Adams
Ann Broadwell

By ______________________________

Attorneys for Petitioners

3. Ongoing project construction and operations under permits previously issued by Respondent are permitted to continue pending Respondent's return to this Court.

IT IS SO ORDERED.

Dated: _______________.

____
The Honorable Diane Wayne
Judge of the Superior Court

Approved as to form:

PILLSBURY MADISON & SUTRO
Ronald E. Van Buskirk
Betsy G. Stauffer

By _______________________

Attorneys for
Real Party in Interest

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
William B. Wong
Frances L. Keeler

By _______________________

Attorneys for Respondent

ADAMS & BROADWELL
Thomas R. Adams
Ann Broadwell

By _______________________

Attorneys for Petitioners

3. Ongoing project construction and operations under permits previously issued by Respondent are permitted to continue pending Respondent's return to this Court.

IT IS SO ORDERED.

Dated: ______________.

____
The Honorable Diane Wayne
Judge of the Superior Court

Approved as to form:

PILLSBURY MADISON & SUTRO
Ronald E. Van Buskirk
Betsy G. Stauffer

By ______________________________

Attorneys for
Real Party in Interest

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
William B. Wong
Frances L. Keeler

By Frances L. Keeler

Attorneys for Respondent

ADAMS & BROADWELL
Thomas R. Adams
Ann Broadwell

By ______________________________

Attorneys for Petitioners

3. Ongoing project construction and operations under permits previously issued by Respondent are permitted to continue pending Respondent's return to this Court.

IT IS SO ORDERED.

Dated: OCT 19 1994.

DIANE WAYNE

The Honorable Diane Wayne
Judge of the Superior Court

Approved as to form:

PILLSBURY MADISON & SUTRO
Ronald E. Van Buskirk
Becky G. Stauffer

By ______________________________

Attorneys for
Real Party in Interest

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
William B. Wong
Frances L. Kesler

By ______________________________

Attorneys for Respondent

ADAMS & BROADWELL
Thomas R. Adams
Ann Broadwell

By Ann Broadwell

Attorneys for Petitioners

chevron

Tentative Ruling

ATTWOOD V. SCAQMD

Petition for Writ of Mandate: Grant

The petition for writ of mandate is granted pursuant to Public Resources Code § 21168.5 and under the substantial evidence standard of review as set forth in Laurel Heights Improvement Assn. v. Regents of University of California (1988) 47 Cal.3d 376, 392. ("Laurel Heights I").

Under the substantial evidence test, the court's analysis is limited to ". . . whether there was a prejudicial abuse of discretion. Abuse of discretion is established if the agency has not proceeded in a manner required by law or if the determination or decision is not supported by substantial evidence." Public Resources Code § 21168.5. The court "must resolve reasonable doubts in favor of the administrative findings and decision." Topanga Assn. for a Scenic Community v. County of Los Angeles (1974) 11 Cal.3d 506, 514.

The court finds that respondent ("District") did not proceed in the matter required by law. The District violated CEQA by approving the project prior to the certification of the EIR and by failing to properly consider and adopt the EIR.

A writ of mandate shall issue (1) ordering the District to set aside its certification of the EIR; and (2) remanding the matter to the District for further proceedings in accordance with CEQA and this court's ruling. **However, this court specifically finds that equitable factors support the continuation of existing operations, and will as such permit such activity to continue, pending compliance with CEQA.** Laurel Heights I, supra, 47 Cal.3d at 423; Public Resources Code § 21168.9. Specifically, existing operations are required for Chevron to comply "clean fuel" mandates. 1 AR 40-41.

In light of this ruling, the court does not address the

#5 dup

sufficiency of the EIR itself. This ruling is not intended to validate the EIR or to prohibit any further environmental review by the District.

I. Approval of project prior to certification of the EIR.

Phase I of the project was "approved" prior to the certification of the EIR and issuance of the permits on 10/25/93.

In reviewing actions undertaken by an agency, the court "'does not pass upon the correctness of the EIR's environmental conclusions, but only upon its sufficiency as an informative document.'" Laurel Heights I, supra, 47 Cal.3d at 392 (quoting County of Inyo v. City of Los Angeles (1977) 71 Cal.App.3d 185, 189). The court should not demand perfection but only a demonstration of an objective, good faith effort to comply. Mount Sutro Defense Committee v. Regents of Univ. of California (1978) 77 Cal.App.3d 20, 37.

The purpose of an EIR is "to identify the significant effects of a project on the environment, to identify alternatives to the project, and to indicate the manner in which those significant effects can be mitigated or avoided." Public Resources Code sec. 21102.1(a). The purpose of an EIR is to inform the public and governmental agencies of the environmental of a proposed project. No Oil, Inc. v. City of Los Angeles 13 Cal.3d 68, 86. The EIR must contain a meaningful discussion of both mitigation measures and project alternatives. Laurel Heights, 47 Cal.3d at 401-403.

While the EIR must indicate a good faith effort at full disclosure, it need not be perfect nor must it contain an exhaustive analysis of all issues. CEQA Guidelines section 15151; Kings County Farm Bureau v. City of Hanford (1990) 221 Cal.App.3d 692. "A prejudicial abuse of discretion occurs if the failure to include relevant information precludes informed decisionmaking and informed public participation, thereby thwarting the statutory goals of the EIR process." Kings County, 221 Cal.App.3d at 712 (citing Laurel Heights, 42 Cal. 3d at 403-405).

And, "Public participation is an essential part of the CEQA process." (Guide. § 15201). That process is invalidated if the project begins before comment is available. Sutter Sensible Planning v. Board 122 Cal.App.3d 813.

Reformulated gasoline projects, such as the project in the instant case, are required to comply with CEQA. Public Resources Code § 21178.1. Pursuant to CEQA, an agency must consider the final EIR prior to approval or disapproval of the project. Public Resources Code § 21061; CEQA Guidelines §§ 15004, 15089; Laurel Heights I, supra, 47 Cal.3d at 394; No Oil Inc. v. City of Los Angeles (1974) 13 Cal.3d 68, 79.

As applicable to the instant case, a "project" is "the whole of an action, which has a potential for resulting in a physical change in the environment, directly or ultimately, and is . . . . [an] activity involving the issuance to a person of a . . . permit . . . or other entitlement for use by one or more public agencies." CEQA Guidelines § 15378(a)(3); Public Resources Code § 21065(c).

Pursuant to Public Resources Code § 21080(a), CEQA applies only to approvals of "discretionary projects," i.e., those projects which "[require] the exercise of judgment or deliberation when the public agency or body decides to approve or disapprove a particular activity," as opposed to "ministerial projects" in which the agency merely determines "whether there has been conformity with applicable statutes, ordinances, or regulations." CEQA Guidelines §§ 15357, 15268.

"Approval" is defined as a decision "which commits the agency to a definite course of action in regard to a project intended to be carried out by any person." CEQA Guidelines § 15352(a); Public Resources Code § 21151. Approval of a private project "occurs upon the earliest commitment to issue or the issuance by the public agency of a discretionary . . . permit . . . or other entitlement for use of the project." CEQA Guidelines § 15352(b). However, the precise date of approval is to be determined by the agency pursuant to its own rules and regulations. CEQA Guidelines § 15352(a).

A. **Approval under District Rule 201.**

District Rule 201, which governs the issuance of a Permit to Construct, provides that:

> "A person shall not build, erect, install, alter or replace any equipment, the use of which may cause the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. A permit to construct shall remain in effect until the permit to operate the equipment for which the application was filed is granted or denied, or the application is cancelled."

According to the stipulated facts in this case, Chevron began the subject field activities in 2/93. In 7/93, Chevron sent a letter to Dr. Lentz, the District's Executive Officer, in order to confirm that certain field activities would be in compliance with Rule 201. Dr. Lentz's 7/7/93 letter confirmed that Chevron could place certain equipment in their final locations, but that Chevron could not make process or utility connections prior to issuance of a permit to construct. The Lentz letter advised that such work would be at Chevron's risk. The construction began prior to the completion of the EIR. Stip. pp. 4-9.

Dr. Lentz's letter was based upon the District's 11/17/89 written interpretation of Rule 201, whereby field activities require prior approval when equipment which could emit or control air contaminants is "a) Beginning to be fabricated on-site or,

"b) In the case of equipment that is delivered fully fabricated, positioned in its final intended location and power and process connections to be made."

Respondent's interpretations of the statutes of which it must enforce and the corresponding rules and regulations are entitled to great weight. Dept. of Health Services v. Superior Court (1991) 232 Cal.App.3d 776; Ralph's Grocery Co. v. Reimel (1968) 69 Cal.2d 172. An agency's interpretation of its own regulations is controlling unless clearly erroneous or inconsistent with the regulation. United States v. Larionoff (1977) 431 U.S. 864; Carmona v. Div. of Industrial Safety (1975) 13 Cal.3d 303.

The court finds that the interpretation of Rule 201 is not unreasonable nor is it inconsistent with the rule. So long as the equipment at issue is pre-fabricated when positioned in its intended final location and is not connected or otherwise operative, the equipment may reasonably be considered as not under construction.

However, the stipulated facts indicate that the equipment was not all pre-fabricated and merely installed at their intended final locations, i.e., that actual construction was taking place. During the period of 8/93 to 9/93, Chevron began to erect a 170-foot reactor/regenerator structure and a 130-foot dehexanizer column, and to make modifications to the existing electrical substation. As of 10/23/93 (prior to the certification of the EIR), the estimated percentage completion for work on the project included the following: furnace work, 11 % complete; reactor/regenerator strucutre, 65 % complete; hydrogen net gas compressor, 14 % complete; dehexanizer column, 40 % complete; new electrical substations, 60 % complete; and modifications to existing electrical substation, 20 % complete.

Thus, the District, under its own rules, should not have permitted activity without the issuance of a Permit to Construct.

B. **Approval within the meaning of CEQA.**

Accordingly, this court finds that the District's action constituted an "approval" within the meaning of CEQA.

Notwithstanding Dr. Lentz's warning that Chevron would undertake field activities at its own risk, the District by its conduct committed itself to "a definite course of action." CEQA Guidelines § 15352(a); Public Resources Code § 21151. Pursuant to its own Rule 201, the District should have issued a permit in order to allow Chevron's activities to proceed.

Moreover, permission to undertake the subject project activities prior to the consideration and approval of a final EIR is not permitted under CEQA.

> "A fundamental purpose of an EIR is to provide decision makers with information they can use in deciding **whether** to approve a proposed project, not to inform them of the environmental effects of projects that they have already approved. If post approval environmental review were allowed, EIR's would likely become nothing more than post hoc rationalizations to support action already taken. We have expressly condemned this use of EIR's." (Emphasis original.)

Laurel Heights I, supra, 47 Cal.3d at 394 (citing No Oil, supra, 13 Cal.3d at 79).

Thus, the EIR should be prepared "as early as feasible in the planning process to enable environmental considerations to influence project program and design and yet late enough to provide meaningful information for environmental assessment." CEQA Guidelines § 15004(b); Laurel Heights I, supra, 47 Cal.3d at 395. "With private projects, the Lead Agency shall encourage the project proponent to incorporate environmental considerations into project conceptualization, design and planning at the earliest feasible time." CEQA Guidelines § 15004(b)(1). The purpose for this requirment is to consider environmental problems at a time "where genuine flexibility remains". Sundstrom v. County 208 Cal.App.3d 296.

Timing of the preparation of the EIR is to be determined by the agency in accordance with the objectives of CEQA. Mount Sutro, supra, 77 Cal.App.3d at 36. Thus, in Mount Sutro, the Regents fufilled the requirements by CEQA by coordinating at an early stage the exchange and evaluation of information between project planners and environmental consultants and eliciting and considering public comments during "this formative stage of planning and review," thereby facilitating the early identification and assessment of significant impacts to "meaningfully influence and effect changes in the proposed projects. . . ." 77 Cal.App.3d at 39.

In contrast, the project activities began well before the environmental review process was completed.[1]

The District began the environmental review process in 10/92 and held a public scoping session held in 11/92. The draft EIR was not circulated until 7/31/93, and a hearing on public comment was not held until 8/23/93. 2 AR 4-48; 6 AR 37; 1 AR 3, 4. The public

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[1] Cf. Stand Tall on Principles v. Shasta Union High School District (1991) 235 Cal.App.3d 772, 781. The court found that selection, as opposed to acquisition, of a project site is not an approval under CEQA because there is no commitment to a defininte course of action. The site was also one of the alternative sites discussed in the EIR. Id.

comment period ended on 9/14/93 and, on 10/25/93, the EIR was certified and the permits were issued. 6 AR 111; 5 AR 1.

Field work began in 2/93 and Chevron received permission to proceed with further field work in 7/93 - prior to the circulation of the draft EIR. By 10/23/93, about 37 % of the field work had been completed and that of 135 pieces of equipment, 69 had been installed on their foundations or in steel structures. A significant portion of the project had been completed even though the EIR had not yet been certified nor were the requisite permits issued. This is clearly more than the beginning of fabrication.

The EIR is intended to analyze the direct and indirect consequences of the project. Public Resources Code § 21083(c); CEQA Guidelines §§ 15064, 15126. For example, the EIR proposed certain mitigation measures regarding traffic impacts of the project, which were rendered somewhat ineffectual by the premature approval of the project and the initiation of construction prior to the certification of the EIR. See 1 AR 160-161, 237-238.

Failure to complete environmental review of the project prior to approval deprives the process of "genuine flexibility." Sundstrom, supra, 202 Cal.App.3d at 307. Timing of the project completion itself indicates that the EIR is a "post hoc rationalization of the agency action." Id. Field activities were begun in 2/93 (8 months before certification of the EIR). As of 10/23/93, the project was 37 % complete. By 2/28/94 (3 months after certification) the project was substantially completed by 2/28/94. Decl. of Brown. The project commenced operation as of 3/9/94 (4 months after certification). Id.

III. Consideration and certification of the EIR.

It is unclear whether or not the EIR was reviewed and considered by the appropriate decision maker.

"[T]he decision-making body or administrative official having final approval authority over a project involving a substantial effect upon the environment [must] review and consider an EIR before taking action to approve or disapprove the project." Kleist v. City of Glendale (1976) 56 Cal.App.3d 770, 778 (citing former CEQA Guidelines § 15085(g), now § 15090). ". . .The requirement exists in part because 'only by this process will the public be able to determine the environmental and economic values of their elected and appointed officials'". Id. at 778 (citations omitted.)

Section 15090 provides that the lead agency is responsible for certifying that the final EIR is completed in compliance with CEQA, and that the decision-making body of the lead agency reviewed and considered the information prior to approving the project.

Section 15090 does not mention delegation of certification duties. Rather, the section gives the lead agency leeway to determine such responsibility. See Comment to CEQA Guidelines § 15090. Nonetheless, the agency may not delegate the **review and consideration** of a final EIR. CEQA Guidelines § 15025. Such action must be taken by the decision-making body. CEQA Guidelines § 15090.

The "decision-making body" is the person permitted by law to approve or disapprove the project. CEQA Guidelines § 15356. By District Rule, this person is Dr. Lentz, the Executive Officer. As such, it would appear that Dr. Lentz would be the person to review and consider the final EIR. However, the EIR was apparently certified by Barry Wallerstein, Deputy Executive Officer. 5 AR 1. Nowhere in his declaration does Wallerstein inform this court of his authority, delegated or actual, to certify the EIR.

Upon remand, the District should clarify who is to certify the EIR, and who (or what entity) is to review and consider the EIR, as well as who is to adopt the findings, statement of overriding considerations, and the mitigation monitoring plan.

IV. **Laches and mootness.**

Chevron has failed to demonstrate that the petition is barred by the doctrine of laches and is moot.

"The affirmative defense of laches requires unreasonable delay in bringing suit 'plus either acquiescence in the act about which plaintiff complains or prejudice to the defendant resulting from the delay.'" Miller v. Eisenhower Medical Center (1980) 27 Cal.3d 614, 624 (citing Conti v. Board of Civil Service Commissioners (1969) 1 Cal.3d 351, 359).

"Prejudice is never presumed; rather it must be affirmatively demonstrated by the defendant in order to sustain his burdens of proof and the production of evidence on the issue. [Citation.]" Id.

"Generally speaking, the existence of laches is a question of fact to be determined by the trial court in light of all of the applicable circumstances, and in the absence of manifest injustice or lack of substantial support in the evidence its determination will be sustained. [Citations.]" Id.

Petitioners could not have filed a CEQA challenge until after the posting of the Notice of Determination on 10/26/93. Chevron has stipulated that by 10/23/93, it had already spent $ 13.7 million on the project. This action was timely filed and diligently brought on 11/12/93, well within the statute of limitations.

Furthermore, the court is permitting a contintuation of existing operations pending the remanding of the EIR for proper attention.

Furthermore, the petition is not rendered moot. The petition specifically seeks to set aside the entire project, not just Phase I. The fact that the project is now fully operating has no effect upon the validity of the permits issued.

V. Proper remedy.

The court need not enjoin the underlying activity upon a finding that CEQA has been violated. Public Resources Code § 21168.9. In making this determination, the court must rely upon traditional equitable principles in deciding whether or not the activity should be enjoined. Laurel Heights I 47 Cal.3d at 423.

An injunction would cause substantial economic harm to Chevron and would adversely affect consumers, as well as the District's obligations under the Clearn Air Act. Decl. of Brown.

Note: Thank you to all counsel. All of the briefs were clear, concise and informative.

PROOF OF SERVICE

STATE OF CALIFORNIA, COUNTY OF ORANGE

At the time of service, I was over 18 years of age and not a party to this action. I am employed in the County of Orange, State of California. My business address is 4695 MacArthur Court, Suite 1100, Newport Beach, CA 92660.

On January 29, 2015, I served true copies of the following document(s) described as **PROJECT PROPONENT PHILLIPS 66 COMPANY's OPPOSITION TO APPEAL OF APPROVAL AND CERTIFICATION OF THE FINAL NEGATIVE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT FILED BY COMMUNITIES FOR A BETTER ENVIRONMENT** on the interested parties in this action as follows:

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General Counsel
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BY E-MAIL OR ELECTRONIC TRANSMISSION: I caused a copy of the document(s) to be sent from e-mail address janis.lucian@clydeco.us to the persons at the e-mail addresses listed in the Service List. The document(s) were transmitted at or before 5:00 p.m. I did not receive, within a reasonable time after the transmission, any electronic message or other indication that the transmission was unsuccessful.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on January 29, 2015, at Newport Beach, California.

Janis A. Lucian

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SOUTH COAST AQMD
CLERK OF THE BOARDS

'15 JAN 28 A6 :49

BEFORE THE GOVERNING BOARD OF THE

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

In the Matter of

SCAQMD'S NEGATIVE DECLARATION AND NOTICE OF DETERMINATION ON PHILLIPS' 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT

PETITION TO SET HEARING DATE FOR APPEAL OF FINAL NEGATIVE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT

TO THE CLERK OF THE DISTRICT BOARD:

Communities for a Better Environment ("CBE") hereby requests a hearing in order to appeal the District's December 12, 2014 decision to adopt a Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project ("Project") under the California Environmental Quality Act

("CEQA"). Pursuant to Rule 1201, this Petition is being filed within ten days of the next Board meeting scheduled for February 6, 2015. For the following reasons, CBE respectfully requests a hearing before the Governing Board on its pending appeal on February 6, 2014, or as soon thereafter as possible.

I. INTRODUCTION

On December 12, 2014, in violation of CEQA's public disclosure mandate, Air District staff quietly approved one piece of a massive expansion of Phillips 66's Carson refinery plant—one of California's largest refineries—on a Negative Declaration, CEQA's minimal level of environmental review. The Project not only increases the refinery's total throughput, but also increases quantities of dirtier, unconventional crudes, such as highly viscous and sulfur-laden Canadian tar sands and explosive, fracked crude from the Bakken shale. Each stage of the cycle of extracting, transporting and refining these dirty crudes creates significant impacts. For example, on July 6, 2013, a train carrying Bakken crude oil exploded, killing forty-seven individuals and destroying nearly half the town of Lac-Mégantic, Quebec.[1] Sadly, that accident became the first in a series of well-publicized derailments and explosions throughout the continent.

The location of the Project also raises important environmental justice concerns in an area already over-burdened with industrial air pollution—an area shown to suffer from, among other health concerns, an increased prevalence of respiratory ailments. Of particular note, the City of Carson, where Phillips 66's refinery would be expanded, contains several schools. A growing body of scientific studies indicate that toxic emissions have a particularly detrimental effect on developing lungs.

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[1] Nicholas Keung, *Lac-Mégantic train victims reach $200M settlement*, THE STAR (Jan. 9, 2015), http://www.thestar.com/news/canada/2015/01/09/200m_settlement_reached_in_lacmgantic_rail_disaster.html.

The Project's increased emissions frustrate the region's long-delinquent attainment of the Clean Air Act's national health-based air quality standards and the Global Warming Solutions Act of 2006, which requires the state to reduce its greenhouse emission levels to 1990 levels by the year 2020. Cal. Health & Safety Code § 38500 *et. seq.* For these reasons, as further discussed below, and the many other reasons detailed in its appeal (attached hereto), CBE petitions the Board to promptly hear its appeal of staff's Negative Declaration.

II. FACTUAL BACKGROUND

CBE, and particularly its members who live in the South Coast Air District, suffer the ill effects of refinery operations, associated accidents, flares, and toxic emissions. CBE's members are on the front lines of industrial pollution and experience public health outcomes that are consistent with high levels of such exposures. These front-line communities score among the state's highest Toxic Release Inventory chemical burdens, and as a result of which experience heightened frequencies of asthma, other respiratory disorders, low birth weight in infants, and other health issues.[2] In light of these alarmingly high levels of background pollution, CBE's members are deeply concerned about the oil industry's recent trend towards increased transport, storage, and refining of dirtier crude oils, and Phillips 66's stated desire to follow that trend at its Carson facility.

In 2013, when the District initiated a public review and comment period for a Draft Negative Declaration regarding the Project, CBE submitted extensive legal and technical comments supporting a full Environmental Impact Report ("EIR"). The Draft Negative Declaration inaccurately characterized the Project as solely intended to increase storage capacity at the refinery. As explained by CBE's attached appeal, the project description failed to include the full scope of the project, which

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[2] OEHHA Cal Enviro Screen 1.1 (amended), Statewide Zip code Result, data available at: http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56, zip code results for 90745 (Carson) and 90744 (Wilmington); see also, results for zip codes 90220, 90211 (Compton), last accessed on January 24, 2015.

would modify the refinery to significantly increase the facility's crude throughput, including increased refining of tar sands and Bakken crude. Despite the substantial evidence to the contrary, the Draft Negative Declaration concluded that the Project would have no significant impacts on the environment and that therefore no EIR was required. The District's public comment period on the Draft Negative Declaration spanned thirty days, ending on October 9, 2013.

Prior to the close of the comment period, CBE submitted several comments noting the substantial flaws and omissions in the Draft Negative Declaration, including: (1) the Project description failed to disclose the scope of use of "advantaged" or "cost-advantaged" crudes, supported by Phillips 66 corporate data evidence; (2) substantial scientific evidence indicating the corrosive, high-sulfur content advantaged oils would increase air emissions and other hazards; and (3) the considerable existing burden in the area surrounding the refinery, which would be exacerbated by the Project.

Since October 2013, CBE, other environmental organizations, and technical experts have submitted extensive comments on other similar projects initiated by Phillips 66 and other petroleum companies utilizing unconventional crude oils, showing that such projects yield highly dangerous fugitive and operational emissions stemming from both process and storage equipment.

On December 22, 2014, CBE received notice that the District issued its Notice of Determination and certified a Final Negative Declaration on December 12, 2014. Other than the listing of the Governing Board members' names on the Final Negative Declaration, there is no evidence that the Governing Board reviewed the Draft Negative Declaration.

On January 2, 2014, CBE sent a letter to South Coast Air Quality Management District staff citing the above-described procedural and substantive defects, and requesting withdrawal of the Final Negative Declaration. After hearing no response from the District staff, CBE filed an appeal with the

Governing Board. To date, Governing Board has failed to acknowledge or respond to CBE's appeal. CBE now requests, pursuant to Rule 1201, that the Governing Board hear CBE's appeal of the disputed Negative Declaration on February 6, 2015, or as soon thereafter as possible.

III. GROUNDS FOR APPEAL

CBE petitions the Governing Board to hear its appeal of the Phillips 66 Carson Crude Oil Storage Capacity Project ("Project") Final Negative Declaration for three main reasons. First, District staff does not have authority under CEQA to approve and certify a final negative declaration. Second, the Project description is inaccurate and artificially constrained. The Project would result in a massive retooling of the refinery, including an increase in throughput, not merely an increase in storage capacity as claimed by Phillips and the District.

Third, the District violated CEQA's mandate that an EIR be prepared when, as in this case, commenters have presented substantial evidence supporting a "fair argument" that the Project may cause significant adverse health and environmental impacts.[3][4] A negative declaration is appropriate only when there is no substantial evidence that the project may have a significant environmental impact.[5] Substantial evidence includes "facts, reasonable assumptions predicated upon facts, and expert opinion supported by facts."[6] An EIR is necessary to resolve "uncertainty created by conflicting assertions" and to "substitute some degree of factual certainty for tentative opinion and speculation."[7] An agency's "decision not to require an EIR can be upheld only when there is *no credible evidence* to the contrary."[8]

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[3] CEQA Guidelines §15162.
[4] Pub. Res. Code §§21002.1(a), 21061.
[5] Pub. Res. Code § 21080(c)(1).
[6] Cal. Code Regs. tit. 14, § 15384.
[7] *No Oil, Inc. v. City of Los Angeles*, 13 Cal.3d 68, 77 (1975) (*quoting County of Inyo v. Yorty*, 32 Cal.App.3d 795, 814 (3d Dist. 1973)).
[8] *Sierra Club v. County of Sonoma* (1992) 6 Cal.App.4th 1307, 1318 (emphasis added).

CBE provided substantial evidence throughout its comments, and presented additional evidence after the close of the comment period in an appeal letter to the Governing Board, demonstrating that the Project is likely to have significant adverse impacts on the environment. That included evidence that the Project will increase the quantity of dangerous crudes transported, stored, and processed at the Los Angeles Refinery. Although the District conceded in response to comments that Phillips 66 has been processing unconventional crudes for some time without disclosure to the public the refinery has been refining relatively low percentages of Canadian tar sands and Bakken crudes until now. The District failed to analyze the potential environmental, health, and safety impacts from increased use of these crude types. Because the Project would enable Phillips 66 to bring in substantially greater amounts of heavy tar sands and volatile Bakken crudes, this analysis is crucial to determining the true environmental impacts of the Project.

Phillips 66's intent to increase the amount of Canadian tar sands and Bakken crudes is evidenced by the project's increased tank storage volume and throughput, Phillips 66's 2012 Summary Annual Report included in CBE's comments on the Draft Negative Declaration, emails sent to the District from Phillips 66 representatives directly stating that the crude tank application was to accommodate Access Western Blend ("AWB") Canadian crude, public statements made by Phillips 66 representatives and a transcript of an investor conference call from the third quarter of 2014 indicating that the company intends to get to "100% advantaged crude in the next year."[9] CBE's comments also include quotes from Phillips 66 representatives stating that the company specifically intends to increase shipments of tar sands and Bakken crudes as "advantaged crudes."

While the Negative Declaration assumes that the project's increased tank storage is only for the purpose of offloading from ships faster and optimizing blending, the companies own statements present a contrary indication. The District failed to evaluate the potential environmental impact of the increase in the amount of these dangerous crudes being transported, stored, and refined at Phillips 66's Refinery.[10] The District also failed to evaluate the potential for a significant increase of sulfur content in the crude, as compared to the baseline, due to the project.

CBE has presented ample evidence in its comments and its appeal letter to the Governing Board to constitute substantial evidence that the Project may have significant adverse environmental, safety, and health impacts. The District failed to consider the differences in Canadian tar sands and Bakken crudes in terms of sulfur content, reactive organic compounds (ROG), and Toxic Air Contaminants (TAC). It is well known, and further documented by evidence provided by CBE in its comments and attached appeal, that heavy, high-sulfur Canadian crudes carry serious environmental and human health implications. Increases in the sulfur content of the crude processed means that the refinery will have to engage in more sulfur processing, which can lead to higher emissions of hydrogen sulfide,[11] increased danger of corrosion, and increased accident risks. CBE identified all of these impacts in comments on the Draft Negative Declaration. Ignoring CBE's substantial evidence to the contrary, the Final Negative Declaration continued to incorrectly state that "[t]he Draft ND does not include a baseline or future changes in crude oil type refined by the LARC because the proposed project will not change, enlarge, or otherwise impact the types and/or quantities of crude oil that LARC currently does and will continue to refine."[12] In its response, the District further missed

[9] Q3 2014 Transcript at p. 6, attached hereto in the appeal document exhibits.
[10] Pub. Res. Code § 15162(a)(3) (requiring an agency to prepare an EIR where new information of substantial importance shows the project will have significant impacts not discussed in a previous Negative Declaration or more severe impacts than previously discussed).
[11] A study by the Norwegian University of Science and Technology explains, "The sulfur compounds in crude oils and natural gas generally exist in the form of free sulfur, hydrogen sulfide, thiols, sulfides, disulfides, and thiophenes. These compounds can cause considerable technical, environmental, economic, and safety challenges in all segments of petroleum industry, from upstream, through midstream to downstream. . . . The major corrosion problems in oil and gas processing facilities are not caused by hydrocarbons but by various inorganic compounds, such as water, hydrogen sulfide, hydrofluoric acid, and caustic. There are two essential sources of these conglomerates: feed-stock contaminants and process chemicals, including solvents, neutralizers, and catalysts (Nenry & Scott, 1994)." Production and processing of sour crude and natural gas - challenges due to increasing stringent regulations, Norwegian University of Science and Technology, 2013, http://www.diva-portal.org/smash/get/diva2:649648/FULLTEXT01.pdf
[12] Final ND at p. F-62.

the mark by pointing to crude oil volume limits at the distillation unit. These volume limits do not limit the percent of sulfur in the crude. An analysis of the Project's potential impact on the baseline sulfur content remains critical to understanding the Project's environmental impacts.

Certain cost advantaged crudes, such as Bakken crude, also differ in vapor pressure and flammability, which determine the levels of ROGs and TACs.[13] The levels of ROGs and TACs fluctuate independent of sulfur content and will result in significant impacts not considered by the District. CBE provided an expert report from Dr. Phyllis Fox submitted for the purpose of analyzing impacts from similar projects elsewhere in the state, which detail the significant, detrimental impacts that result from the chemical composition diluents used to blend \with this type of crude.[14] These potential impacts include: increases in ROG that contribute to existing violations of ozone ambient air quality standards; increases in TAC emissions that significantly increase health risks to already over-burdened local communities; increases in malodorous sulfur compounds that result in significant odor impacts; increases in combustion emissions that contribute to existing violations of ambient air quality standards; and increases in flammability that increase the potential for more dangerous accidents involving storage and process equipment.[15] In addition, the Department of Transportation has published safety alerts for all forms of transport of Bakken crude oil because the volatility of this crude increases the danger of transporting it by ship, rail, or any other means.[16] The Final Negative Declaration failed to address any of these potentially significant impacts from the Project's intended increase in Canadian tar sands and North Dakotan Bakken crude oils. For all the reasons stated above, and in CBE's comments and attached appeal, Air District staff issued the Final Negative Declaration in error. That document, and the associated project approvals, must be withdrawn

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[13] *See* Appeal Document Exhibit U (Dr. Fox report to Valero Crude By Rail Project EIR – Benicia).
[14] *Id.*
[15] *Id.*

pending the District's preparation of a full EIR that discloses, analyzes and mitigates the significant impacts resulting from the increased transport, storage, and refining of dirty and dangerous crudes in Phillips 66's crude slate.

IV. THE DISTRICT HAS NO PROCESS FOR APPEALING A STAFF'S DECISION ON A NEGATIVE DECLARATION

The District lacks any procedure for appealing staff decisions on CEQA determinations for projects where the District is the lead agency. CBE sent the Governing Board a formal appeal letter on January 9, 2015, but received no response to the letter or any indication that the Governing Board considered the letter. In addition, the Final Negative Declaration included no procedures for appeal. California law provides that when non-elected officials adopt a Negative Declaration, the adoption may be appealed to "the agency's elected decisionmaking body."[17] As the agency's elected decisionmaking body, the Governing Board, must provide a mechanism for appealing Negative Declarations.

V. REQUEST FOR HEARING

CBE is appealing staff's decision to the Governing Board because: (1) the District failed to prepare an EIR for this project despite the substantial evidence supporting a fair argument that the project will have significant impacts on the environment; (2) District staff lacks authority under CEQA to approve and certify a final negative declaration; and (3) the District lacks a process for appealing negative declarations to its elected governing body, all in violation of CEQA. For these

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[16] The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, January 2, 2014, http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_111F295A99DD05D9B698AE8968F7C1742DC70000/filename/1_2_14%20Rail_Safety_Alert.pdf.

[17] Cal. Code Regs. tit. 14, § 15074 (providing that provides that "[w]hen a non-elected official or decisionmaking body of a local lead agency adopts a negative declaration or mitigated negative declaration, that adoption may be appealed to the agency's elected decisionmaking body, if one exists."); Cal. Pub. Res. Code § 21151 (providing that "[i]f a nonelected decisionmaking body of a local lead agency certifies an environmental impact report, approves a negative declaration or mitigated negative declaration, or determines that a project is not subject to this division, that certification, approval, or determination may be appealed to the agency's elected decisionmaking body, if any.").

reasons, CBE requests that Governing Board reject the staff's Negative Declaration and rescind all related Project approvals pending preparation of a full EIR that discloses, analyzes, and mitigates the Project's significant and adverse environmental impacts.

Accordingly, CBE respectfully requests a hearing on its appeal during the Board's next scheduled meeting date of February 6, 2015, or as soon thereafter as possible.

DATED: January 27, 2015

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Counsel for Petitioner Communities for a Better Environment

CERTIFICATE OF SERVICE

STATE OF CALIFORNIA, COUNTY OF ORANGE

I, Debi Gloria, declare that I am and was at the times of the service hereunder mentioned, over the age of (18) eighteen years, and not a party to the within cause. My business address is: UC Irvine School of Law, 401 East Peltason, Suite 1000, Irvine, California 92697.

On January 27, 2015, I caused to be served the below listed document(s) entitled:

PETITION TO SET HEARING DATE FOR APPEAL OF FINAL NEGATIVE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT

To be sent to:

Clerk of the District Board
21865 E. Copley Drive
Diamond Bar, California 91765

[X] By Personal Service via Courier:

I personally dispatched the documents to a bonded courier service to have them delivered to the persons at the addresses listed in item 5. Delivery was made to the party or by leaving the documents at the party's office with some person not younger than 18 years of age between the hours of eight in the morning and six in the evening.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on January 27, 2015, at Irvine, California.

Debi Gloria
Law Clinics Administrator
UC Irvine School of Law

A. Yana Garcia (State Bar No. 282959)
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COMMUNITIES FOR A BETTER ENVIRONMENT

BEFORE THE GOVERNING BOARD OF THE
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

In the Matter of **The South Coast Air Quality Management District's December 12, 2014 Approval and Certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project**	**APPEAL OF APPROVAL AND CERTIFICATION OF THE FINAL NEGATVIE DECLARATION FOR THE PHILLIPS 66 CARSON CRUDE OIL STORAGE CAPACITY PROJECT**

I. INTRODUCTION

This appeal challenges the South Coast Air Quality Management District's ("District") failure to comply with the California Environmental Quality Act ("CEQA"), Public Resources Code § 21000 *et. seq.*, 14 Cal.Code Regs § 15000 *et. seq.* in its approval and certification of the Final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project ("Project") on December 12, 2014. The District's approval of a Final Negative Declaration for the Project fails to comply with CEQA because there is substantial evidence in the administrative record of a fair argument that the Project may have a significant, adverse effect on the environment and human health; thereby requiring preparation of an environmental impact report ("EIR").[1]

Because the District Governing Board is the governing body of the agency, the Governing Board has a non-delegable duty under CEQA to certify a Final Negative Declaration.[2] The Governing Board has no published, formal procedures for evaluating and deciding on CEQA documents. Additionally, the Final Negative Declaration approved and certified on December 12, 2014 appears to have been considered, approved and certified solely by District staff. This process makes the District's decision to approve and certify the Final Negative Declaration unclear, and renders the approval and certification procedurally deficient.

Moreover, because the District is also the highest-elected decision-making body for the agency, CEQA requires that the Governing Board provide for an appeal of the District staff's CEQA determination.[3] Accordingly, Communities for a Better Environment ("CBE") hereby requests that the Governing Board deny certification, withdraw and re-consider the District's approval of the Final Negative Declaration for the Project in accordance with its non-delegable authority under CEQA Guidelines, §15025(b)(1), or, in the alternative, appeals the District's approval and certification of the same Final Negative Declaration pursuant to the same CEQA Guidelines section.

II. FACTUAL BACKGROUND

CBE, and its members, particularly those who reside in and around refineries located in the South Coast Air District, have long expressed their concern with refinery operations, their emissions, and potential hazards including flares and accidents that result from refinery operations. Since at least the year 2013, CBE, CBE members and allies have expressed serious concerns with industry trends to increase the transport, storage and refining of dangerous crudes from new North American, domestic and Canadian sources. These concerns have been noted in

[1] *See* CEQA Guidelines, 14 Cal. Code Regs § 15064 (f)(1) ("if a lead agency is presented with a fair argument that a project may have a significant effect on the environment, the lead agency *shall* prepare an EIR even though it may also be presented with other substantial evidence that the project will not have a significant effect." (emphasis added).

[2] CEQA Guidelines, §15025(b)(1).

[3] Cal. Health and Safety Code § 40420; CEQA Guidelines §15025(b)(1) (requiring the decision-making body to approve a negative declaration prior to approving a project); *c.f. Id.* § 15074(f) (providing for appeal of a decision by a local lead agency to adopt a Negative Declaration to the agency's highest elected decision-making body).

correspondence to the District attached hereto at Exhibit A, and have formed the basis for comments submitted to District Staff in relation to project proposals and permit approval processes including the environmental review process for the Phillips 66 Carson Project, as well as other Phillips 66 project proposals throughout the state.

On or about September 6, 2013, the District issued for public review and comment a Draft Initial Study and Negative Declaration for the Project pursuant to Public Resources Code section 21092.

The Project description contained in the Draft Negative Declaration described the project as one involving the following components: (1) installation of one new 615,000 bbl nominal capacity crude oil storage tank, which is identified as tank 2640, and which would be accompanied by a geodesic dome for fugitive emission controls; (2) increasing the permitted throughput limit of two 320,000 bbl nominal capacity existing external floating roof crude oil storage tanks, Tanks 510 and 511, from 4.562 million bbl per year to 18 million bbl per year for each tank and installing geodesic domes on each of those tanks to control fugitive emissions; (3) installation of two new, 2,100 gallons per minute (gpm) crude oil feed/transfer pumps to transfer crude oil into and out of the new tank (Tank 2640); (4) installing of one new, 14,000 bbl nominal capacity water draw surge tank (Tank 2643), including geodesic dome, pumps, and pipelines; (5) installation of three new heat exchangers and one steam trap to assist in water treatment; (6) installation of tie-ins to the manifold of the Pier "T" crude oil delivery pipeline from Berth 121; and (7) installation of one new electrical power substation.

The Draft Negative Declaration and Notice of Intent concluded that the Project components described above would not have a significant impact on the environment and therefore, no EIR would be required for the Project.

SCAQMD invited comments on the Draft Negative Declaration for a period of 30 days, and closed the comment period on October 9, 2013.

On October 9, 2013, prior to the close of the comment period, CBE submitted comments, based on, *inter alia*, the following flaws in the Draft Negative Declaration's analyses:

1. CBE asserted in comments that the Project description was piecemealed from a larger,

company-wide project to front-end the transport, storage and refining of "advantaged" or "cost advantaged" Western Canadian tar sands, and North Dakota Bakken crudes. In support, CBE included Phillips 66 corporate and market data indicating that Phillips 66 considers "advantaged" or "cost advantaged" crudes to be comprised of Western Canadian tar sands and North Dakota Bakken crudes, and that based on a variety of publicly available data, the company intended to increase shipments of such crudes specifically to its Los Angeles refinery, including the Carson facility,

2. CBE also identified project specifications further indicating that the Project was designed to facilitate the Los Angeles Refinery's receipt, storage and processing of "advantaged" crudes;
3. CBE pointed to substantial evidence, including reports, data and other scientific information showing why such new crude would cause significant environmental impacts including but not limited to, increased air emissions and risks of hazards as a result of sulfur corrosion from higher-sulfur content crudes; and
4. CBE highlighted the cumulatively considerable, existing burden in the area surrounding the project, specifically in the City of Carson, and in Wilmington.

In January 2014 CBE members and staff met with District staff and members of the Governing Board about another project, and asked for updates and information about the Phillips 66 Carson Project. CBE staff and members specifically asked the District to consider the health and hazards impacts that could result from increasing the amount of tar sands and Bakken crudes blended in Los Angeles refinery crude slates, noting the Phillips 66 Los Angeles refinery in particular. Between February and November 2014 CBE staff and members made additional, repeated requests for information regarding the Project from District staff and some members of the Governing Board, both individually and during public comment at regular Governing Board meetings, and for information specifically regarding the air emissions and health impacts of transporting, receiving and refining tar sands and Bakken crudes.

Since October 2013, CBE and other environmental health and justice organizations have submitted extensive comments on other projects proposed by Phillips 66 in Santa Maria, San

Luis Obispo County, and in Rodeo, Contra Costa County, as well as other non-Phillips 66 projects to transport, store and refine tar sands and Bakken crudes. In these comments, CBE, and other allied environmental health and justice organizations, advocates and technical experts, have exposed new information regarding the potential for highly dangerous fugitive and operation emissions from both process and storage equipment, and the increased risks of potentially catastrophic hazards associated with such crudes.

A relevant selection of these comments and other relevant documents are attached hereto in Exhibits.

On December 12, 2014, after over a year of reviewing and responding comments District staff published its Notice of Determination and Project approval, finalizing and certifying the same Draft Negative Declaration released on September 6, 2013 for comment, as the Final Negative Declaration for the Project.

On December 22, 2014, CBE staff received by mail, the District's notice of determination, project approval and approval of the final negative declaration. The Notice and Project approval documents indicate that the Final Negative Declaration was certified on the same day the District issued its Notice of Determination: December 12, 2014.

Despite the names of all Governing Board members being listed on the second page of the final negative declaration, the Governing Board has not approved the project and the final negative declaration for the Project is not reflected in any publicly available SCAQMD Board meeting agendas or minutes documents.[4] Thus, while the notice received by CBE indicates that the final negative declaration was certified, there is nothing contained on the record to indicate that it was considered by the Governing Board. In fact, the list of all Governing Board members affirmatively misleads the public that the Governing Board has reviewed the document, when it

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[4] The only reference to the Governing Board's consideration of the Draft or Final Negative Declarations for the Project that appear to be publicly available, is found in the Governing Board Agenda packet for the December 5, 2014 regular Governing Board meeting. That agenda, and "Attachment C" to the agenda, are attached hereto at Exhibit (X). The attachment indicates only that the Governing Board reviewed a summary of the active projects for which the District is the lead agency wherein the Draft Negative Declaration for the Project was included. District's Staff's description of that status of the Draft Negative Declaration at the time of the Board meeting provides only that the Staff's consultant "is making edits to the responses and finalizing the Draft ND." (*See* Final Negative Declaration. Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project.)

has not.

In response to the comments submitted by CBE on October 9, 2013, District staff claim the following, *inter alia*: (1) CBE's characterization of project specifications indicating that the Project may be designed to facilitate the increased transport, storage and processing of tar sands or Bakken crudes is mistaken as CBE misunderstands the refinery's operations, and the purpose of the Project is merely to increase efficiency and capacity to offload and store larger crude tank deliveries made by marine vessel to the Los Angles Refinery; (2) that CBE's characterization of any increased emissions and/or significant environmental impacts including cumulative impacts is similarly misguided as CBE misunderstands the purpose of the Project; and (3) that the Phillips 66 Los Angeles Refinery has already been receiving, storing and processing Canadian crudes including tar sands crudes and tar sands crude blends since 2002, and the District has included in its response to Comments, new information to support this claim, which was not previously released or made publicly available at any time during the comment period.[5]

The District's revealing of new information at the same time in which its staff has rubber stamped a cursory environmental review document, itself requires immediate withdrawal of the District's approval of the Final Negative Declaration for the Project, and requires reconsideration of the appropriateness of a negative declaration under the circumstances. In particular, the Final Negative Declaration fails to analyze the current and post-project crude quality baseline, as required by CEQA.

In public statements made by Phillips 66 representatives and through the environmental review process for its two additional projects proposed in San Luis Obispo and Contra Costa County, Phillips 66 continues to expose additional information regarding its plans, and its execution of its plans to transport, process and refine tar sands and Bakken crudes at all of the company's California refineries. For example, in a transcript from an investor conference call from the third quarter of 2014, Phillips 66 Chairman and CEO is quoted stating that the company will "get **to 100% advantaged crude in the next year"** or so as we continue to move these

[5] *See generally*, Final Negative Declaration, Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project; and at F-46.

projects forward around infrastructure.[6] Such statements and information find further support in Project applications and related application documents including correspondence between District staff and Phillips 66 representatives, attached hereto in exhibits. All of these facts require the District to immediately withdraw the its approval of the Final Negative Declaration, as the document still fails to account for the impacts that stem from Phillips 66's change in crude slate, as further described below.

On January 2, 2014 CBE sent a letter to SCAQMD staff requesting withdrawal of its approval of the final negative declaration as a result of notice issues, some of the issues raised above, in comments, and in the District's responses to comments. After hearing no response from District staff, CBE hereby files this appeal to the Governing Board.

III. GROUNDS FOR APPEAL

CBE appeals the District's approval of the Project's Final Negative Declaration for two reasons. First, District staff does not have authority under CEQA to approve and certify a Final Negative Declaration on its own. Approving final negative declarations is a non-delegable duty of the District Governing Board.[7] Second, the District violated CEQA's mandate that an EIR be prepared when, as in this case, commenters have met the "fair argument" legal standard by presenting substantial evidence that the Project may cause significant adverse health and environmental impacts and when new, material information regarding the project has become available since the close of the comment period.[8] As such, and for the additional reasons briefly herein, and supported by the attached Exhibits we appeal the District's December 12, 2014 final determination approving and certifying the Phillips 66 Carson Project Final Negative Declaration.

[6] Q3 2014 Transcript at p. 14, attached hereto in exhibits (emphasis added).
[7] CEQA Guidelines, §15025(b)(1).
[8] CEQA Guidelines §15162.

THE DISTRICT MUST PREPARE AN EIR FOR THIS PROJECT

1. CEQA provides a low threshold for when an agency must prepare an EIR.

CEQA must be interpreted to "afford the fullest possible protection to the environment within the reasonable scope of the statutory language."[9] CEQA requires a lead agency to assess a project's impacts on the environment.[10] Preparation of an EIR is required whenever substantial evidence in the record supports a *fair argument* that significant impacts may occur.[11] The "fair argument" standard creates a low threshold for requiring preparation of an EIR.[12]

Because issuing a Negative Declaration has a terminal effect on the environmental review process, CEQA provides that a lead agency may only issue a Negative Declaration instead of a full EIR if there is "no substantial evidence, in light of the whole record before the lead agency, that the project may have a significant effect on the environment."[13] An EIR is necessary to resolve "uncertainty created by conflicting assertions" and to "substitute some degree of factual certainty for tentative opinion and speculation."[14] An agency's decision not to require an EIR can be upheld only when there is *no credible evidence* to the contrary.[15]

2. The District's decision to approve and certify the Negative Declaration ignores potentially significant impacts from allowing for the increased transport, storage and processing of dangerous domestic and Canadian derived crudes—which the District admits for the first time in responses to comments have been processed in the past at the Lost Angeles Refinery.

CBE cited throughout its comments evidence that the project is likely to have significant impacts on the environment, especially given the fact that the refinery intends to increase the

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[9] *Communities for a Better Environment v. Calif. Resources Agency* (2002) 103 Cal. App. 4th 98, 110.
[10] Pub. Res. Code §§ 21002.1(a), 21061.
[11] *Ocean View Estates Homeowners Ass'n v. Montecito Water Dist.* (2004) 116 Cal.App.4th 396, 399; Pub. Res. Code § 21080(d); CEQA Guidelines § 15384(a) ("'Substantial evidence' as used in these guidelines means enough relevant information and reasonable inferences from this information that a fair argument can be made to support a conclusion, even though other conclusions might also be reached.").
[12] *Ocean View Estates*, 116 Cal.App.4th at 399; *Citizens Action to Serve Students v. Thornley* (1990) 222 Cal.App.3d 748, 754.
[13] Pub. Res. Code § 21080(c)(1).
[14] *No Oil, Inc. v. City of Los Angeles* (1975) 13 Cal.3d 68, 77, quoting *County of Inyo v. Yorty* (3d Dist. 1973) 32 Cal.App.3d 795, 814.
[15] *Sierra Club v. County of Sonoma* (1992) 6 Cal.App.4th 1307, 1318 (emphasis added).

amount of dangerous and dirty domestic crudes, and that this Project will necessarily involve offloading, storage and refining of such crudes at the Los Angeles Refinery. The District's responses to comments concerning the Phillips 66 Carson Project expose the agency's cavalier approach to the serious human health and environmental concerns raised by commenters to that project, as well as other, similar projects. In its responses, the District--for the first time--admits the refinery has been using relatively low percentages of Canadian crude, with Table F-1 showing overall Canadian crude at 9.5% over the years, with the highest percent at 21% in 2013[16] so the refinery has the potential to greatly increase use of this crude oil source.[17] The District states that Phillips 66 not only plans to bring down heavy tar sands and dangerous Bakken crudes in the foreseeable future, but it also concedes that the refinery has been processing the same crude types, without disclosure to the public for a significant amount of time.[18]

Publicly exposing this fact in the same act in which it rubber stamps its minimal review of the Project's potential impacts presents a clear dereliction of the agency's duty to protect the environment and to minimize air emissions in the South Coast.[19] Furthermore, because the District revealed this critical new information for the first time in its responses to comments, it must analyze the resulting impacts.[20] The impacts resulting from the increased transport, storage, and refining of dirty and dangerous crudes in Phillips 66's crude slate must be analyzed in an EIR.

The new information contained in the District's responses to comments also requires

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[16] *See e.g.*, Notice of Determination – Final Negative Declaration Phillips 66, Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project – SCH No. 2013091029, at Appendix F, Response 2-9, F-46.
[17] ND Appendix F, p. F-46.
[18] *See e.g., Id.* at F-42.
[19] *See City of Redlands v. County of San Bernardino* (2002) 96 Cal.App.4th 398, 405 (holding that an (EIR) must be prepared under CEQA whenever substantial evidence in the record supports a "fair argument that a proposed project will have a significant effect on the environment" (citations omitted).); *see also*, CEQA Guidelines §15384, and 42 U.S.C. § 7401(b)(1)-(3), (c), *supra*; *and see* Cal. Health and Safety Code § 40001(b) (District rules and regulations may, and at the request of the state board provide for the prevention and abatement of air pollution episodes which, at intervals, cause discomfort or health risks to, or damage to the property of, a significant number of persons or class of persons.).
[20] Pub. Res. Code § 15162(a)(3) (requiring an agency to prepare an EIR where new information of substantial importance shows the project will have significant impacts not discussed in a previous Negative Declaration or more severe impacts than previously discussed).

withdrawal of approval and reconsideration of the Final Negative Declaration for the Project, and requires preparation of an EIR. The District's responses to comments, specifically conceding that Phillips 66 already processes and refines Canadian crude blends including tar sands crudes and as well as domestic Bakken crudes substantiate a fair argument that the Project may cause significant environmental impacts. Moreover, this new information, coupled with Phillips 66's more recent Corporate statements cited above further indicate that there are substantial changes to the circumstances under which the Project is being undertaken, requiring a new environmental review process.[21]

2. *The District cannot ignore substantial evidence weighing in favor of preparing an EIR.*

Phillips 66's own stated project objectives substantiate at least a fair argument that the Project may cause significant adverse environmental impacts that were not addressed by the District in the environmental review process for the Final Negative Declaration. For example, the District has failed to analyze the potential significant increase in baseline sulfur content in the refinery due to a change in the *average* crude oil slate toward substantially increased Canadian tar sands crude oil, facilitated by the new and expanded storage tanks.[22] The Final Negative Declaration assumes that the project's increased tank storage volume and throughput is only for the purpose of offloading from ships faster and to optimize blending.[23] The District asserts that this is unrelated to and cannot cause any downstream changes in the refinery, and it appears that the District's exposure of the fact that the refinery already processes both Canadian and domestic Bakken crudes is included in responses to comments in order to support this claim.[24]

The District's conclusion, however, is incorrect, and fails to adequately address CBE's comments concerning the impacts resulting from a shift in the quality of crude received and

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[21] *See* CEQA Guidelines § 15162 (requiring preparation of subsequent environmental review documents when there are changes in circumstances surrounding a project proposal, notwithstanding approval or certification of the initial environmental review document.

[22] For the purpose of this appeal, this point is made, notwithstanding the District's claim that there will be no increased to the Refinery's throughput levels.

[23] See Final Negative Declaration at pp. 1-3 and 1-5 to 1-6.

[24] Final Negative Declaration Appendix F, at pp. F-42.

stored at the Carson facility.

The record shows that both the District and Phillips 66 are clear that the Project storage tanks <u>will</u> be used for the express purpose of bringing in larger volumes of "advantaged" crude oil from Canada and the Bakken shale, implying a change in the overall crude slate quality by volume, notwithstanding the fact that the Refinery may process some inherently lower volumes of Canadian and Bakken crudes currently and may have in the past. Phillips 66's 2012 Summary Annual Report included in CBE's comments on the Draft Negative Declaration provides a map showing the company's plans to bring increased shipments of what it calls "advantaged crudes" to the LA Refinery, specifically from Canada and from the North Dakota Bakken fields. CBE's comments also quote Phillips 66 representatives stating that the company specifically intends to increase shipments of tar sands and Bakken crudes as "advantaged crudes." There is also more in our comments on the draft ND showing where the company stated its intention to bring these "advantaged crudes" to California. Phillip's Application for Tank 2640, and related documents attached hereto in Exhibits also include emails from the District asking Phillips 66 for more information regarding the new tanks project. These emails provide further documentation of the company's intent to use the Carson facility tanks to receive and store tar sands crudes for use in the refinery's operations.

> "As I mentioned on the phone, **I am requesting additional information in support of your crude tanks applications**. Please provide the following information: • Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics." (Janice West, AQMD, January 10, 2013) . . . (emphasis added).
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> "In the attached table, there are columns for SJV[25] crude, "crude oils", Cal crude, and crude hybrid. **What is the origin of "crude oils"?** (Janice West, AQMD, Sept. 3, 2013) . . . (emphasis added).
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> "**Sorry, I meant *geographic* origin** or other identifier, (similar to California or San Joaquin Valley or Canada), just to identify that column as different and not an average of the others). . . . (Janice West, AQMD, Sept. 3, 2013) . . . (emphasis added).

[25] SJV is San Joaquin Valley – a California crude the company has used historically.

"Our Crude buyer calls it AWB crude.[26] **It is from Canada."** (John W. Matthews, Phillips 66, Sept. 3, 2013) (emphasis added).[27]

Phillips 66's more recent corporate statements also re-iterate the purpose of the tanks. In Phillips 66's 2014 "fact book" description of its "midstream" West Coast operations, the company states the following: "*We are adding additional tankage at our Los Angeles Refinery to increase access to advantaged waterborne crudes.*" This statement directly refutes the District's responses to comments and their reliance on the claim that CBE "incorrectly assumes that increasing crude oil storage capacity will result in a change in the quality of crude oil blend that is processed at the refinery." [28]

In response to comments the District states that "[w]hile SCAQMD staff does not dispute that crude oils have varying chemical properties and characteristics, including sulfur content, the commenter makes an unsubstantiated assumption that the proposed project will cause the type of crude oil delivered to the LARC to change, when in actuality, the proposed project would not affect the ability, nor would it have any effect on the types of crude oil feedstocks that can and will be received at the LARC."[29] Taken together these statements and correspondence point to the presence of substantial evidence that the company specifically intends to bring in a higher volume of advantaged crude oils from Canada, and that the storage tanks in the Project are indeed for the express purpose of facilitating this effort.

The AWB Canadian and other Candian tar sands crudes described above in the Application documents, moreover, are heavy, with extremely high sulfur content. At 4%, these crudes rank much higher in the presence of sulfur as compared to other crude oils that are also considered to be high in sulfur content.[30] For example, when compared to the average California crude oils historically used in the refinery, including San Joaquin Valley and other crudes, the

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[26] AWB stands for Access Western Blend, it is a heavy, highly corrosive and high sulfur diluted bitumen, or tar sands blend. *See* crude monitor description of properties, relative index and data available at: http://www.crudemonitor.ca/crude.php?acr=AWB

[27] *See* attached exhibits.

[28] *See* Appendix F: Phillips 66 Los Angeles Refinery – Carson Plant Crude Oil Storage Capacity Project, throughout.)

[29] See *Id.*, at F-62.

[30] http://www.crudemonitor.ca/crude.php?acr=AWB; *see also* CBE's Technical comment to the Draft Negative Declaration at p. 13.

California Energy Commission found the following:

> Kern County: In 2004, oil from Kern County accounted for 77 percent of California's total onshore production and over **69 percent of the state's total oil production**. Approximately 58 percent of the crude oil has an API of 18 degrees or less. The Kern River oil field, located in the eastern San Joaquin Valley, accounts for approximately 24 percent of Kern County oil. Kern River oil is characteristically heavy and sour with an API of 13.4 degrees and a sulfur content of 1.2 percent.
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> Los Angeles Basin: The Los Angeles Basin is a sedimentary plain extending from central Los Angeles south through the Long Beach area. The two largest fields by area in this region are the Wilmington and the Huntington Beach fields with average APIs of 17.1 and 19.4 degrees, and average sulfur contents of 1.7 and 2.0 percent, respectively.[31]

Yet, while CBE's comments to the Draft Negative Declaration identified the need for baseline crude slate data including sulfur content at the refinery as necessary to determine the potential overall increase in sulfur content due to the Project, the District failed to do so.

CBE's comments point out that "The ND should have identified baseline crude slates and sulfur content data at the Phillips 66 Los Angeles refinery complex, in addition to the percent sulfur of the unconventional crudes which can potentially be processed due to the Project changes discussed, and volumes of the baselines and crude changes."[32] The Final Negative Declaration, however, states that "The Draft ND does not include a baseline or future changes in crude oil type refined by the LARC because the proposed project will not change, enlarge, or otherwise impact the types and/or quantities of crude oil that LARC currently and will continue to refine."[33] The Final Negative Declaration bases this assertion on its claim that the distillation unit or "crude" unit limits the refinery operation, and without increasing the crude oil there, nothing downstream could change.[34] This statement cannot be true, because crude oil volume limits at the distillation unit do not limit the percent of sulfur in the crude. Downstream of the

[31] California Crude Oil Production and Imports, California Energy Commission, APRIL 2006, CEC-600-2006-006, available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF
[32] CBE JMay Draft Negative Declaration Comments at p. 14.
[33] Final ND at p. F-62
[34] *See Id.*

distillation unit inside the refinery, it is the capacity of the sulfur processing units such as the hydrotreaters and sulfur recovery units that limit how much sulfur can be processed.[35]

The Final Negative Declaration fails to provide any baseline for sulfur processing such as the hydrotreater and sulfur recovery units and instead, it merely provides the range of sulfur that can be processed -- 1 to 3%. But, within the refinery's design range, a baseline can fluctuate over years, and the introduction of extremely high sulfur Canadian tar sands crude oil can increase that overall sulfur processing level, which can result in large increases in the amount of extremely toxic and corrosive sulfur compounds processed in the refinery. Thus, the Final Negative Declaration failed entirely to evaluate the potential for a significant increase of sulfur, as compared to the baseline, due to the Project.

The Final Negative Declaration notes that because there is a small range of sulfur that the refinery is designed to process, even if very high sulfur crude is introduced, it can will be mixed with lower sulfur crude so that the average level of sulfur goes down to the designed range that the refinery can process. The District states:

> "The commenter's opinions do not take into account the processing of a crude oil blend, and thus do not reflect the operations at the Refinery. At p. F-40
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> "For instance, if the crude oil to be purchased by the LARC has a sulfur content higher than what can be processed by the equipment, LARC must blend it with a crude oil that has a lower sulfur content, so that the sulfur content of the overall blend falls within the proper specifications. The blend of crude oil that is processed at the LARC contains sulfur between the narrow range of one to three percent based on the processing constraints of the Refinery equipment. In the event that there is no low sulfur crude oil available on-site or for purchase to blend with the higher sulfur content crude oil, the LARC will not purchase the high sulfur content crude oil because it cannot be processed without blending. This process of purchasing and blending crude oils has been in practice at LARC for many years and

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[35] *See generally*, Appendix 3 to Chevron Modernization Project, at Exhibit (X), available at: http://chevronmodernization.com/wp-content/uploads/2014/03/Appendix_3_Overview.pdf and the Norwegian University of Science and Technology, available at: http://www.diva-portal.org/smash/get/diva2:649648/FULLTEXT01.pdf and in attached exhibits.

> will not change as a result of the proposed project. For these reasons, the proposed project will not change the types of crude oil processed by the LARC and will not require any modifications to any crude oil refining equipment at the LARC."[36]

Again, the District mischaracterizes CBE's analysis. CBE did account for the range of sulfur in the overall blend processed at the refinery and the District response fails to include any information relevant to establishing an actual sulfur baseline in the refinery. As described above and in more detail in CBE's comments to the Draft Negative Declaration, the question of sulfur baseline is not about whether the refinery can stay within its designed general range of the percent sulfur in individual crude oils processed, it is total baseline that the refinery *has* been operating at over the last few years, and whether the Project will cause an increase in the *total mass* of sulfur, and the overall refinery *average* sulfur percent in the crude oil, and whether the Project will increase those values within the design range. The design range at the refinery is not the basis for a CEQA evaluation, the actual conditions are.[37]

The potential for a significantly increased sulfur percent in the crude oil processed by the refinery due to the Project also may imply higher volumes of hazardous hydrogen sulfide ("H2S") in the refinery, increased danger of corrosion, and increased accident risks, as discussed in CBE's comments on the Draft Negative Declaration. These concerns and potential significant impacts were dismissed by the District on the basis that there was no change to the *types* of crude oils processed as described above, but since the information above shows that there is substantial information providing a fair argument that the refinery plans for the crude oil tanks to facilitate the introduction of "advantaged crudes" including Canadian tar sands crude oils, the Final Negative Declaration's conclusion is incorrect, and it cannot avoid the need for providing a full review and analysis of the potential for increased hazardous sulfur compounds in the refinery that are hazardous to human health and increase accident risk.

H2S is present in sour crude oil, and is also formed in the refinery from the presence of sulfur in the crude oil. More sulfur in the crude oil could mean more H2S in the refinery. While,

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[36] *See* Final Negative Declaration at p. F-44.
[37] *Communities For A Better Environment v. South Coast Air Quality Management District*, 48 Cal.4th 310, 324.

there are also many other acutely hazardous and corrosive sulfur compounds that are formed because of this, H2S remains a large source, and provides another example of what must be evaluated in accounting for the potential environmental impacts of a change in crude slate at the Los Angeles refinery.

CBE discussed the corrosive and accident hazards from H2S in CBE's Draft Negative Declaration comments, and there is a broad range of materials on this subject available. The District is well aware of this but refused to address issues related to the increase in H2S because it erroneously concluded there is no nexus between the crude oil tanks and the high sulfur crude plans of the company.

A study by the Norwegian University of Science and Technology explains in detail, the history of H2S chemistry in oil refineries.[38] The report summarizes many points about hazardous sulfur chemistry due to sour crude oil as follows:

> "The sulfur compounds in crude oils and natural gas generally exist in the form of free sulfur, hydrogen sulfide, thiols, sulfides, disulfides, and thiophenes. These compounds can cause considerable technical, environmental, economic, and safety challenges in all segments of petroleum industry, from upstream, through midstream to downstream. . . .
>
> The major corrosion problems in oil and gas processing facilities are not caused by hydrocarbons but by various inorganic compounds, such as water, hydrogen sulfide, hydrofluoric acid, and caustic. There are two essential sources of these conglomerates: feed-stock contaminants and process chemicals, including solvents, neutralizers, and catalysts (Nenry & Scott, 1994)."[39]

The 2014 EIR for the Chevron Richmond Refinery Modernization Project also describes this hydrotreating sulfur removal process that is present in refineries, and describes how these impurities can interfere with refinery processes. For example, Section 3.2.2 of Appendix 3 to that document states:[40]

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[38] Production and processing of sour crude and natural gas - challenges due to increasing stringent regulations, Norwegian University of Science and Technology, 2013, http://www.diva-portal.org/smash/get/diva2:649648/FULLTEXT01.pdf

[39] *Id.*

[40] Chevron Refinery Modernization Project EIR, March 2014, Appendix 3, Overview of Oil Refining Process, Chevron Modernization Project, 2013, http://chevronmodernization.com/wp-

"Another important natural characteristic of crude oil is that different types of crude oil have differing amounts of sulfur content. Sulfur occurs naturally in crude oil, but sulfur content is restricted by federal and State air quality laws in refined products (e.g., there are standards limiting the amount of sulfur that can be present in refined products like gasoline). To meet these regulatory restrictions on sulfur content in refined products, sulfur is removed from the various fractions of crude oil during the refining process. [emphasis added] ...

When an oil has less sulfur, it is referred to as being "sweet." Crudes with more sulfur are referred to as being "sour." Although there is no regulatory threshold of sulfur content for dividing sweet crude oils from sour crude oils, oils with less than 0.5% sulfur content are generally referred to as "sweet." ...

Most sulfur present in crude oil is bonded within hydrocarbon molecules, although some is present as hydrogen sulfide (H2S) gas . This is different from "elemental" or pure sulfur (a yellow crystalline substance when at room temperature), which is a usable product. During the refining process, the sulfur atom is removed from the hydrocarbon molecule. **This process is called "hydrotreating"** because it includes the use of hydrogen. The hydrocarbon fractions are combined with hydrogen in the presence of a catalyst and elevated temperatures and pressures. The catalyst, temperature, and pressure separate the sulfur from the hydrocarbon molecule and the sulfur combines with the available hydrogen to produce a gas called hydrogen sulfide (H2S). This hydrogen sulfide gas is then treated, as explained below, to create "elemental" sulfur, which is sold as a product by Chevron. The Modernization Project includes several components to allow Chevron to remove more sulfur from the Facility's feedstocks and thereby refine higher sulfur crude oil and gas oil in the future."

Section 3.4.2 of the same document further provides:

"Hydrocarbons separated in the crude unit distillation process and SDA unit contain naturally occurring sulfur and other natural impurities such as nitrogen and metals. One of the key later steps in the refinery process involves chemical reaction processes that include a "catalyst" – a material that promotes or speeds up chemical reactions to produce either a finished product or another interim material to be processed further, such as in the Cracking step. These impurities can interfere with the cracking processes.

content/uploads/2014/03/Appendix_3_Overview.pdf

An example of the kinds of accidents and releases that can occur in sulfur processing units was listed in a Contra Costa County Northern California website publication, in a summary of refinery accidents. The H2S release described there occurred during a hydrotreater upset:

> "An upset occurred in the straight run hydrotreater unit in the light oil processing area. Subsequently, fires occurred in the vacuum flasher heater furnace and crude unit heater furnace. Hydrocarbons, H2S, and smoke released offsite. Level 3 under CWS, sirens activated."[41]

An added example of the range of potential impacts from the increased presence of H2S is contained in the Agency for Toxic Substance and Disease Registry, (ATSDR) H2S Fact Sheet. That fact sheet states that:

> *"Just a few breaths of air containing high levels of hydrogen sulfide gas can cause death. Lower, longer-term exposure can cause eye irritation, headache, and fatigue."*[42]

While CBE does not dispute that Phillips 66 can buy a range of crude oils, there is also no disputing that the company explicitly plans to use the Project tanks to facilitate a significant increase in receiving, storing and processing "advantaged crude" oils, and specifically tar sands and Bakken crudes, as has been made clear repeatedly by its own representatives. It is also well known and documented on the record including the exhibits attached hereto, that heavy, high sulfur Canadian crude oils and Bakken crudes carry serious environmental and human health implications.[43] In addition to the procedural and other substantive flaws contained in the District's approval and certification of the Final Negative Declaration for the Project, the Final Negative Declaration fails to evaluate the baseline and fails to account for increased sulfur processing in the refinery due to the potential major increase in high sulfur crude oil. The Final

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[41] Contra Costa County – including Equilon refinery hydtrotreater accident, July 18, 2001, http://cchealth.org/hazmat/accident-history.php

[42] ATSDR, 2006, Division of Toxicology and Environmental Medicine ToxFAQs, http://www.atsdr.cdc.gov/tfacts114.pdf

[43] These two crudes are those which have been identified by Phillips 66 as explicitly included in the company's current definition of "advantaged" or "cost advantaged" crudes, as they are relatively less expensive than other crudes and can greatly increase Phillips 66's profit margin. While these two crude types may cause distinct impacts, both indisputably cause significant, detrimental impacts as a result of their chemical composition and blend with diluents as further described in the attached exhibits including the expert reports from Dr. Phyllis Fox, submitted for the purpose of analyzing impacts from similar projects elsewhere in the state. See Exhibits U, included in attached Exhibit Index, with exhibits forthcoming.

Negative Declaration thereby ignores the critical need to evaluate the potential significant impacts due to increased hazardous sulfur materials in the refinery and dismisses the possibility that the refinery's current baseline sulfur content could increase. By this omission the Final Negative Declaration omits a necessary analysis of substantial evidence supporting a fair argument that the Project has the potential to cause significant environmental impacts, due to the potential to greatly increase Canadian tar sands crude oil as described above, and as further described in CBE's comments to the Draft Negative declaration. The District also appears to assume that because N. Dakota Bakken crude oil has been used at the refinery previously it was not necessary to evaluate environmental impacts caused by significant increases in the use Bakken crude oil that will be facilitated by the Project. As previously discussed, Phillips 66 specifically stated that the new tankage as for the purpose of bringing in "advantaged crude" oils. Phillips identified both Canadian crude and N. Dakota Bakken crude oil as the two advantaged crudes it is seeking to bring to the refinery. CBE provided information in the comments on the Draft ND on the problems of Bakken crude oils, which are more volatile and can increase accident risk in refineries.

Furthermore, the Department of Transportation has published safety alerts for all forms of transport of Bakken crude oil (not just rail), so the ship transport proposed in the Project is also vulnerable to this increased danger due to the volatility of this crude oil.[44] Baselines of the refinery crude oil in general are missing and an evaluation of the impacts of the increases in Bakken crude oil in transportation, and in the refinery are also missing, because the District stated there is no nexus between the company's advantaged crude plans and the new tanks. Phillips 66 statements, however, clearly warrant a full evaluation of these potential impacts.

Other characteristics of the "advantaged" crudes, or specifically the AWB crudes identified by Phillips 66 in correspondence to the Distrcit, such as its vapor pressure or flammability, may also differ in significant ways from the crudes processed in the Los Angeles Refinery's current crude slate. These other constituents and properties are not a function of the

[44] The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, January 2, 2014, http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_111F295A99DD05D9B698AE8968F7C1742DC70000/filename/1_2_14%20Rail_Safety_Alert.pdf, included in attached Exhibit Index, exhibits forthcoming.

API gravity or the sulfur content and are present independent of them. Thus to the extent the District relies on its responses to comments to refute the need to analyze the impacts from these new, distinctly sourced crudes, the District is incorrect.

The vapor pressure of crude determines to a large extent the amount of reactive organic compound (ROG) and Toxic Air Contaminant (TAC) emissions that are released when crude is transported, stored, and refined. Thus, a crude slate may even have identical sulfur content and weight, but would still result in dramatically different ROG and TAC emissions.[45] Similarly, the nature of the chemical bonds in crude determines the amount of energy and hydrogen that must be supplied to refine it. Thus, a crude slate may have identical sulfur and weight, but a different mix of chemicals that would affect the amount of energy and hydrogen required to convert it into refined products.[46]

These differences—in both chemical and physical characteristics other than API gravity and sulfur content— fluctuate independent of sulfur content and API gravity and will result in significant impacts that have not been considered by the District, and are absent from the District's responses to comments, and the Final Negative Declaration analyses. Just some of these impacts include, for example, significant increases in ROG emissions, contributing to existing violations of ozone ambient air quality standards; significant increases in TAC emissions, resulting in significant health impacts in an already over-burdened local setting as described in more detail below; significant increases in malodorous sulfur compounds, resulting in significant odor impacts; significant increases in combustion emissions, contributing to existing violations of ambient air quality standards; and significant increases in flammability, thus increasing the potential for more dangerous accidents involving storage and process equipment

Moreover, as explained in response to similar project proposals, the above crude characteristics also contribute to train derailments or spills on-site.[47] And, the Final Negative

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[45] *See* Exhibit U. Dr. Fox report to Valero Crude By Rail Project EIR – Benicia.
[46] *Id.*
[47] *Id.*

Declaration and the District's responses to CBE comments fail to respond to CBE comments raising these concerns. For example, the District stated in the Final ND that a new condition will be set so that the Project tanks will not receive crude oil brought in by rail. Because the project tanks represent an extremely large new source of crude oil storage and throughput (over 50 million barrels per year in throughput), this condition does preclude the Project from having a significant potential to allow an increase in transport by rail. Indeed, the extent of increase in the overall throughput capacity involved in the project, appears to show that the Project will free up other existing storage tank space in the refinery. Since the refinery is not taking a permit requirement that precludes crude by rail offloading to *all* refinery tanks, the Project also has the potential to also allow an increase in crude offloading by rail in other parts of the refinery, in addition to the crude offloading by ship to these Project tanks. Consequently, the potential impacts from rail still need to be evaluated.

3. *The District's decision to approve and certify the Negative Declaration ignores cumulative impacts from other projects and environmental justice concerns.*

Currently there are 3 refinery projects being proposed in Wilmington and the adjacent City of Carson, as well as additional project-related permit applications at various stages of review by the District. All 3 projects directly impact many of CBE's members and other residents living *directly on the fenceline* of the refineries at which they are being proposed.

These 3 projects include:

1) The Project at issue in this appeal;

2) The Phillips 66 Wilmington Ultra Low Sulfur Diesel Project, for which the District issued a Draft EIR on September 26, 2014; and

3) The Tesoro-BP Refinery Integration Project, for which the District issued a Notice of Preparation of a Draft Environmental Impact Report on September 9, 2014 (and for which the District is also reviewing two Title V permit revisions and renewals--for the Tesoro Marine Terminal 2 and the Tesoro Hynes Terminal in Long Beach).

Wilmington and the cities of Carson and Long Beach rank among the State's top most pollution-burdened and vulnerable areas.[48] Residents of these communities live with the day-to-day impacts of various forms of heavy industry, oil extraction and refining operations, port and other goods-movement and transport activities, including significant levels of air pollution caused by diesel truck and railroad transport.[49] As such, these residents rely heavily on the oversight of agencies like the District to ensure that permitting and project approval decisions regarding additional, highly polluting industrial projects are made wisely, with careful attention to the true range of environmental and health impacts resulting from each individual project alone, and in the context of existing cumulatively considerable burdens.[50]

Despite the existing burden on this area, the District is conducting an impermissibly superficial level of environmental review for projects directly impacting some of the region's most vulnerable neighborhoods. While this problem is in large part a result of inaccurate and often misleading project descriptions contained in the applications submitted by refinery operators, the District is responsible for ensuring that CEQA and other air quality and human health protective requirements are met before it moves forward in issuing or approving any permits or other project-related approvals, including approvals of environmental review documents and permit renewals or revisions.[51]

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[48] Wilmington, Carson and parts of Long Beach 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. (*See* http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?&extent={"xmin":-13166567.802417224,"ymin":4001409.3038827637,"xmax":13157213.82108084,"ymax":4005584.676552836,"spatialReference":{"wkid":102100}}&appid=a4a95185c71f4817bf03aeae25923695 (last accessed, Dec. 23, 2014).

[49] *See Id.*

[50] *See, Laurel Heights Improvement Assn. v. Regents of Univ. of California* (1988) 47 Cal.3d 376, at 394 (holding that the significant cumulative effects of a project must be considered in an EIR, and specifying that such required cumulative effects should encompass "past, present, and reasonably anticipated future projects.); *see also*, CEQA Guidelines, § 15064 (h)(1) (also requiring preparation of an EIR, where cumulative impacts are considerable, and providing that "[w]hen assessing whether a cumulative effect requires an EIR, the lead agency shall consider whether the cumulative impact is significant and … An EIR must be prepared if [a] Project's incremental effect, though individually limited, is cumulatively considerable[,]" meaning that "incremental effects of an individual project are significant when viewed in connection with the effects of past projects … other current projects, and … probable future projects"), and §15355 ("'Cumulative impacts' refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts"); *see also*, Clean Air Act, Declaration of Purpose, at 42 U.S.C. § 7401(b)(1)-(3), (c)(providing that the purpose of the Act is to enhance the quality of the Nation's air resources so as to promote the public health and welfare; and to encourage and assist the development and operation of regional air pollution prevention and control programs to do the same.).

[51] *See* Cal. Pub. Res Code § 21082.2(a) (requiring the lead agency to determine whether a project may have a significant effect on the environment based on substantial evidence in light of the whole record.); *see also Citizens*

4. The District has no process for appealing a staff's decision on a negative declaration.

Counsel for CBE has extensively reviewed the District Rules, website and other materials. There are no procedures for appealing staff decisions on CEQA documents for projects where the District is the lead agency. Also, the Final Negative Declaration included no procedures for appealing the decision. Given the vital import of this project and the information provided on the processing of more dangerous crude oil at this facility, the public and the Governing Board members must have a robust review process. Accordingly, the District should withdrawl its staff approval, adopt a procedure for processing appeals of this sort through an official process, and then process this appeal according to these duly adopted protocols. If the District decides to process the appeal in an ad hoc manner, we respectfully request that CBE be provided at least 30 minutes to present to the Governing Board. Moreover, the public should be provided the opportunity to comment on this item at a duly noticed Governing Board meeting.

Assoc. For Sensible Development of Bishop Area v. County of Inyo (1985) 172 Cal.App.3d 151("The lead agency must consider the whole of an action, not simply its constituent parts, when determining whether it will have a significant environmental effect."); and *see* CEQA Guidelines § 5041(setting forth the Lead Agency's Authority to mitigate negative environmental impacts, and providing that "A lead agency for a project has authority to require feasible changes in any or all activities involved in the project in order to substantially lessen or avoid significant effects on the Environment.").

III. CONCLUSION

For these reasons, and for the additional reasons expressed in CBE's comments on the above listed projects, as well as the additional, attached correspondence and exhibits we appeal the District's certification of the Negative Declaration and we urgently request that the District take immediate steps to withdraw the December 12, 2014 Notice of Determination of the approval and certification of the Final Negative Declaration for the Phillips 66 Carson Project.

Dated: January 9, 2015

Respectfully submitted,

/ s

Yana Garcia, Staff Attorney
Maya Golden-Krasner, Staff Attorney
Attorneys for Petitioner
COMMUNITIES FOR A BETTER ENVIRONMENT

Comments

on

Revised Draft Environmental Impact Report

for the

Phillips 66
Rail Spur Extension
and Crude Unloading Project

Santa Maria, California

Prepared

for

Communities for a Better Environment
Sierra Club
ForestEthics
Center for Biological Diversity

November 24, 2014

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Table of Contents

I. INTRODUCTION

The Phillips 66 Santa Maria Refinery (SMR), located in San Louis Obispo County, is proposing to modify an existing rail spur to accommodate train delivery of cost-advantaged crude oils, to replace local supplies. The proposed tracks and unloading facilities would be designed to accommodate unit trains of up to five unit trains per week, consisting of 80 tank cars and associated locomotives and other supporting cars as well as periodic manifest trains of fewer cars not dedicated to SMR oil (Project). I was asked by Communities for a Better Environment (CBE), the Sierra Club, ForestEthics, and the Center for Biological Diversity to review the Revised Draft Environmental Impact Report (RDEIR or Santa Maria RDEIR)[1]and prepare comments on a limited number of issues. This RDEIR replaces a former Draft Environmental Impact Report on a similar Project (DEIR)[2] issued in November 2013 that I also commented on.

My evaluation, presented below, indicates the RDEIR fails to disclose the link between the Rail Spur Project and three other directly related projects: (1) the Propane Recovery Project at Phillips 66's Rodeo facility; (2) the Rodeo Refinery Marine Terminal Offload Limit Revision Project; and (3) the Throughput Increase Project at the Santa Maria Refinery. The impacts of these directly related projects should have been evaluated as a single project. Together, they result in many significant impacts that were not disclosed in the Rail Spur Project RDEIR.

The RDEIR fails to evaluate the impacts resulting from a significant switch in crude slate, from locally sourced heavy crudes to tar sands crudes. The entire Project, comprising the four piecemealed projects, would result in significant unmitigated air quality, global warming, water supply, biological, and corrosion-caused risk of upset and other impacts, either not disclosed, improperly analyzed, or not mitigated in the RDEIR.

Finally, the RDEIR's hazard analysis fails to include the portions of the route where train accidents are most likely to occur due to steep grades and poor condition of tracks and bridges – from the stateline to the rail yards in Roseville and Colton, fails to analyze a worst case spill, and fails to disclose the significant difficulty of cleaning up a tar sands spill to waterways. The railroad tracks in these omitted areas parallel the water supply for most of California. A derailment that spilled significant amounts of tar sands crudes in these waterways could shut down the water supply for most of the state, resulting in significant unmitigated impacts on agricultural and municipal water supplies and significant aquatic biological impacts.

My resume is included in Exhibit 1 to these comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution

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[1] San Luis Obispo County, Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report and Vertical Coastal Access Project Assessment. October 2014. SCH # 2013071028: Available at: http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/Phillips+66+Company+Rail+Spur+Extension+Project+(Oct+2014)/Phillips+SMR+Rail+Project+Public+Draft+EIR.pdf.

[2] Marine Research Specialists (MRS), Phillips 66 Company Rail Spur Extension Project Public Draft Environmental Impact Report and Vertical Coastal Access Assessment. November 2013.

control; greenhouse gas emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; hazard investigations; risk of upset modeling; environmental permitting; nuisance investigations (odor, noise); environmental impact reports/statements, including California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documentation; risk assessments; and litigation support.

I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. 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 documents. This work includes Environmental Impact Reports (EIRs), Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries as well as various other permitting actions for tar sands and light shale crude refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas and liquefied natural gas (LNG) facilities in Texas, Louisiana, and New York. I was a consultant to a former owner of the subject refinery on CEQA and other environmental issues for over a decade and am thus very familiar with both the Rodeo Refinery and the Santa Maria Refinery and their joint operations.

My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598 and *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310.*

II. THE PROJECT IS PIECEMEALED

The Phillips 66 San Francisco Refinery (SFR) consists of two facilities linked by a 200-mile pipeline. Santa Maria RDEIR, Fig. 2-2. The Santa Maria Refinery (SMR) is located in Arroyo Grande, in San Luis Obispo County, while the Rodeo Refinery is located in Rodeo in the San Francisco Bay Area. The Santa Maria Refinery mainly processes heavy, high sulfur crude oil and sends semi-refined liquid products, *e.g.*, gas oil and pressure distillates[3], to the Rodeo Refinery for converting into finished products. See, *e.g.*, Propane Recovery RDEIR, p. 3-25.

[3] The permits to operate for the Santa Maria Refinery and various pump stations along the pipeline indicate that the materials sent from Santa Maria to Rodeo are gas oil and "pressure distillates." The "pressure distillates" are referred to as "naphtha" in the subject RDEIRs. However, there are different types of naphtha, depending upon the boiling range. Full range naphtha, which is presumably what "pressure distillate" is intended to capture, is the fraction of hydrocarbons boiling between 30 C and 200 C. It consists of a complex mixture of hydrocarbons generally having between 5 and 12 carbon atmos and comprises 15% to 30% of the crude oil by weight. Light naphtha is the fraction boiling between 30 C and 90 C and consists of molecules with 5 to 6 carbon atoms. See, *e.g.*, http://en.wikipedia.org/wiki/Naphtha.

Phillips 66 is planning to replace a significant portion of its baseline crude slate with cost-advantaged crudes delivered to its California refineries by ship and rail. There are currently four related projects at the San Francisco Refinery (comprising the Santa Maria and Rodeo Refineries) that have recently been permitted or that are currently in the process of being permitted that are inextricably linked and should have been evaluated as a single Project under CEQA. Two are located at the Rodeo end of the pipeline and two are located at the Santa Maria end of the pipeline. These four projects are:

1. Santa Maria Refinery Throughput Increase Project;[4]
2. Santa Maria Refinery Rail Spur Project (RDEIR);
3. Rodeo Refinery Propane Recovery Project;[5]
4. Rodeo Refinery Marine Terminal Offload Limit Revision Project.[6]

I previously commented on the relationship between the Santa Maria Refinery Throughput Project, the Santa Maria Refinery Rail Spur Project,[7] and the Rodeo Refinery Propane Recovery Project[8] in comments on previous CEQA documents. These comments are included here in Exhibits 2 and 3. I reassert these comments as they are still valid and have not been addressed in either the Santa Maria Refinery Rail Spur Project RDEIR or the Propane Recovery RDEIR.

However, the SMR Rail Spur Project and Rodeo Refinery Propane Recovery RDEIRs both raise a new issue that seeks to demonstrate that these two projects are not related. This new issue, an alleged vapor pressure constraint, has not been addressed in other comments on piecemealing. The SMR Rail Spur Project RDEIR, p. 2-31, asserts out of the blue, without mentioning the Rodeo Refinery Propane Recovery Project:

> "Prior to pipeline shipment to the Rodeo Refinery the naphtha and gas oils are stored in tanks located at the SMR. These storage tanks have vapor pressure limits are required by the San Luis Obispo County Air Pollution Control District (SLOAPCD) permit, which limits the vapor pressure to 11 pisa [sic]. Historically, and currently the SMR tanks operate at about 10 psia (pounds per square inch absolute). These pressure limits restrict the amount of propane/butane that can be contained in naphtha and gas oils that are shipped to the Rodeo Refinery. The majority of the

[4] Marine Research Specialists, Phillips 66 Santa Maria Refinery Throughput Increase Project, Final Environmental Impact Report, October 2012 (SMF FEIR); Available at: http://slocleanair.org/phillips66feir.

[5] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project Recirculated Draft Environmental Impact Report, SCH # 2012072046, October 2014, Available at: http://www.cccounty.us/DocumentCenter/View/33804.

[6] ERM and BAAQMD, CEQA Initial Study, Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Application 22904, December 2012; Phillips 66, Application for Authority to Construct and Minor Modification to Major Facility Review Permit, Revision of Permit Condition 4336 Part 7, Phillips 66 San Francisco Refinery; Major Facility Review Permit, Phillips 66 – San Francisco Refinery, Facility #A0016, Condition 4336, pp. 497-498, August 1, 2014.

[7] Phyllis Fox, Comments on Environmental Impact Report for the Phillips 66 Rail Spur Extension Project, Santa Maria, California, Prepared for Sierra Club, San Francisco, January 27, 2014.

[8] Phyllis Fox, Comments on Environmental Impact Report for the Phillips 66 Propane Recovery Project, Prepared for Shute, Mihaly & Weinberger LLP on behalf of Rodeo Citizens Association, November 15, 2013.

propane/butane that is contained in the crude oils process at the SMR ends up in the refinery fuel gas. Figure 2-10 provides a simplified flow diagram of the SMR."

The Rodeo Refinery Propane Recovery Project RDEIR, on the other hand, includes a brief discussion of the Santa Maria Refinery. This discussion first asserts that "[t]he proposed Project [Propane Recovery] is independent of and would have no effect on SMF [Santa Maria Facility] operations." Propane RDEIR, p. 3-25. It goes on to make an argument, again out of the blue, that is very similar to the one cited above from the Santa Maria Refinery Rail Spur Project RDEIR (Propane RDEIR, pp. 3-25/26):

> "The storage tanks located along the 200-mile pipeline between the two refineries have maximum vapor pressure limits imposed by the San Luis Obispo County and San Joaquin Valley Air Pollution Control Districts which constrain the amount of butane and propane that can be included in the semi-refined products. Increasing the amount of butane and propane in the semirefined products would increase the vapor pressure of the material. Historically and currently these storage tanks contain products which are at or near the maximum vapor pressure limits. Additional butane and/or propane would cause the products to exceed the vapor pressure limits of the storage tanks. Accordingly, no new butane and propane can be added to the semi-refined products sent from the Santa Maria Refinery to the Rodeo Refinery regardless of the types of crude oil that may be processed at the Santa Maria Refinery."

These arguments attempt to demonstrate that there can be no link between these two projects as vapor pressure permit limits on tanks that store the gas oil and pressure distillate sent from Santa Maria to Rodeo would prohibit any increase in propane and butane as they historically and currently operate near their limits. These claims are incorrect as the assertions are wrong. There either are no vapor pressure limits on the subject tanks, or the materials stored in them have vapor pressures far below their permitted limits.

A. Vapor Pressure Constraints Are Unsupported

The RDEIRs contains no support whatsoever for these vapor pressure claims. Thus, it fails as a CEQA document. Support should include identification of the permits, tanks, and permit conditions that restrict vapor pressure and certified vapor pressure monitoring data for each subject tank. None of this information is in the record.

Therefore, I researched the issue, obtained permits, and identified the tanks that store the subject gas oil and pressure distillate, and obtained vapor pressure monitoring data from the San Luis Obispo County Air Pollution Control District (SLOCAPCD). My research indicates that these claims are wrong.

1. Santa Maria Refinery Tanks

The Santa Maria Refinery produces two semi-refined products – gas oil and pressure distillate. These products are stored in on-site tanks and sent by pipeline to the Rodeo Refinery to convert them to finished products such as gasoline. Emissions from these tanks are regulated by the SLOCAPCD Permit to Operate for the Santa Maria Refinery (Refinery Permit).[9] The Refinery Permit indicates that gas oil is stored in Tanks 800 and 801 and pressure distillate is stored in Tanks 550 and 511. PTO Conditions II.B.1.a and d, p. 8. The vapor pressure of the materials stored in these tanks should not appreciably change during pipeline transport to Rodeo. As discussed below, the vapor pressures of both gas oil and pressure distillate stored in tanks at the Santa Maria Refinery sent to Rodeo are significantly less than claimed in the RDEIRs.

a. Pressure Distillate Tanks 800/801

Pressure distillate, the more volatile of the two semi-refined products, is stored in 52,000-barrel, welded-shell, dome-roof tanks that are controlled by a methane blanket and vapor recovery system (Process A-2). These tanks must comply with SLOCAPCD Rule 425[10]. Rule 425, Section D.5.b applies. This section exempts these tanks from vapor pressure limits as emissions are controlled with a vapor loss control device listed in Section E.3 (E.3 Vapor Recovery System). Thus, there are no vapor pressure limits on the tanks that store pressure distillate that is sent to Rodeo as the vapors are recovered, contrary to the assertion in the SMR Rail Spur Project RDEIR that there is a vapor pressure limit of 11 psia.

The SMR Rail Spur Project RDEIR further asserts that the "SMR tanks operate at about 10 psia", without identifying the tanks. SMR Rail Spur Project RDEIR, p. 2-31. As gas oil is much less volatile, this comment likely refers to pressure distillate. Regardless, even if the pressure distillate tanks were limited to a vapor pressure of 11 psia (which they are not as they are otherwise controlled), the vapor pressure of the pressure distillate that is stored in them is not "about 10 psia". Rather, annual emission inventory data obtained from the SLOCAPCD (Exhibit 4) indicate that the pressure distillate tanks have operated at 6.2 psia over the period 2009 to 2013. Thus, the claims in the SMR Rail Spur Project RDEIR, p. 2-31, are wrong as to the pressure distillate storage tanks at the Santa Maria Refinery. These tanks do not have vapor pressure limits as they are controlled. Further, they are operating far below the erroneously claimed limit of 11 psia.

b. Gas Oil Tanks 500/501

Gas oil is stored in 76,500 barrel welded-shell, external floating pontoon roof, single shoe seal tanks. Rule 425, Section D.4, limits the vapor pressure of these tanks to 0.5 psia. Vapor pressure data that I obtained from the SLOCAPCD (Exhibit 4) indicate that the gas oils stored in these tanks had true vapor pressures of 0.27 psia over the period 2009 to 2013, much less

9 Permit to Operate No. 44-52, Phillips 66 Company - Santa Maria Refinery, November 6, 2013.

10 SIP Rule 407.A.2, also cited in this condition, is superceded by Rule 425. Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (2).

than 0.5 psia. The SLOCAPCD permit engineer explained that when higher vapor pressure material is encountered, it is routed to the pressure distillate tanks.[11]

2. The SMR-to-Rodeo Refinery Pipeline

The semi-refined products stored in Tanks 500, 501, 800, and 801 are pumped into the 200-mile long pipeline and sent to Rodeo for refining into finished products. There are several pump stations along this pipeline, used to increase the pressure as needed to overcome pressure losses from friction during transport. Storage tanks are present at some of these pump stations.

These materials are generally sent directly to Rodeo, without being diverted to tanks along the pipeline, as suggested in the Propane Recovery Project RDEIR, pp. 3-25/26. Phillips Pipeline LLC modified operation of this pipeline several years ago to reduce off-loading of gas oil and pressure distillate at pump stations.[12] While it is possible that an upset or operational abnormality could require material to be temporarily offloaded at pump station tanks, this is not the normal operational mode. Further, as discussed elsewhere, the vapor pressure of the semi-refined products are far below the vapor pressure limits. The former Creston and Summit pump stations were not needed after the operational change and thus no longer have active permits.[13] Other pump stations along the pipeline are primarily used just to push the material along.[14]

Thus, gas oil and pressure distillate that enters the pipeline at Santa Maria arrive at Rodeo with the same vapor pressure. The operation is steady state with little variation in measured vapor pressures from year to year.[15] The vapor pressure data reported by SLOAPCD (Exhibit 4) indicates that these tanks operate far below their permit limits. Within the SLOCAPCD, only the Santa Margarita and Shandon pump stations have active SLOCAPCD permits for storage tanks.

a. SLOCAPCD Pump Stations

Santa Margarita Pump Station Tanks

The Santa Margarita Pump Station Permit to Operate[16] lists four tanks. Three of them (55422, 55408, 110404) have vapor pressure limits of 11 psia, consistent with pressure distillate. Two of these pressure distillate tanks (55422, 55408) are vented to a carbon absorption vapor control system when pressure distillate is stored. The fourth tank (175420) has a vapor pressure limit of 1.5 psia. Vapor pressure data that I obtained from the SLOCAPCD (Exhibit 4) indicates the following vapor pressure ranges for these four tanks over the period 2009 to 2013:

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[11] Personal communication, Dean Carlson, SLOCAPCD, to Phyllis Fox, November 20, 2014.

[12] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (5).

[13] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 20, 2014, Re: P66 Pump Stations.

[14] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (5).

[15] Email from Dean Carlson, SLOCAPCD, to Phyllis Fox, November 21, 2014, Re: SMR Questions, Response (4).

[16] SLOAPCD, Permit to Operate Number 404-9, Phillips Pipeline LLC, Santa Margarita Pump Station, May 2, 2012, Condition 5.

- Tank 55408: 0.26 to 4.79 psia (limit: 11 psia)
- Tank 55422: 0.36 to 5.05 psia (limit: 11 psia)
- Tank 11040: 0.24 to 0.4 psia (limit: 11 psia)
- Tank 175420: 0.07 to 0.49 psia (limit: 1.5 psia)

All of these tanks are operating at vapor pressures far below their permit limits. Thus, the claim in the RDEIRs that they are operating close to their limits, precluding any increase in propane and butane, is incorrect.

Shandon Pump Station Tank

The Shandon Pump Station Permit to Operate lists a single 35,000 barrel pontoon floating roof tank, permitted to store organic liquids with a true vapor pressure not to exceed 1.5 psia.[17] The SLOCAPCD inventory data also indicate that gas oil has been stored in this tank. Over the period 2009 to 2013, the true vapor pressure ranged from 0.12 psia to 0.24 psia, substantially lower than the 1.5 psia vapor pressure limit. Thus, the claim in the RDEIRs that this tank is operating close to its vapor pressure limit, precluding any increase in propane and butane, is incorrect.

b. *SJVAPCD Pump Station Tanks*

There are five pump stations in the San Joaquin Valley Air Pollution Control District (SJVAPCD) along the subject pipeline that have active permits to operate and which include tanks that could store gas oils and pressure distillate, if offloaded during transit to the Rodeo Refinery: (1) McKittrick (S1521); (2) Sunset (S 1522); (3) Shale (S1523); (4) Midway (S1525); and (5) Junction (S 1518). While I was unable to obtain either permits to operate or vapor pressure data for these tanks due to inadequate review time, there is no reason to expect that the vapor pressure of the SMR gas oils and pressure distillates shipped out of the SLOCAPCD into the segment of the pipeline under the jurisdiction of the SJVAPCD (and beyond the Bay Area Air Quality Management District (BAAQMD)) would change during transit to Rodeo. Further, there would be little if any reason to transfer pipeline material into these tanks, once destined for Rodeo.

[17] SLOCAPCD, Permit to Operate Number 505-4, Phillips Pipeline LLC, Shandon Pump Station, May 2, 2012, Condition 5.

B. Refinery Fuel Gas

The SMR Rail Spur Project RDEIR asserts that the majority of the propane and butane would be partitioned into the refinery fuel gas. SMR Rail Spur Project RDEIR, p. 2-31. This depends on the design of the crude tower, *i.e.*, the temperature cut points, which was not disclosed in the RDEIR. Distillate cut points could be optimized to route more of the propane and butane into the naphtha. However, I agree that most of the butane likely would be partitioned into the refinery fuel gas, but a significant amount of the propane would be present in the pressure distillate. Butane is present in much lower amounts than propane in the tar sands crudes identified in the RDEIR.

Regardless, the amount partitioned to the fuel gas at Santa Maria would depend on the amount present in the imported crudes, which would depend largely on the type of diluent if tar sands are imported, or otherwise, the specific light crude, as some are highly enriched in propane and butane.

The SMR Rail Spur Project RDEIR fails as a CEQA informational document as none of the information required to address this point is disclosed. Further, the semi-refined products from refining rail-imported crudes at the Santa Maria Refinery will generate additional amounts of propane and butane when refined at Rodeo, compared to the SMR baseline crude slate. Thus, the fuel gas argument is without merit.

C. Source of Increased Amounts of Propane and Butane Feedstocks at Santa Maria Refinery

The Santa Maria Rail Spur Project and Propane Recovery Project RDEIRs attempt to rebut any connection between these two projects by hiding behind the vapor pressure argument. However, this argument is not persuasive, as demonstrated above. In fact, most all of the cost-advantaged crudes flooding into the market will allow the SMR to produce propane/butane-rich, semi-refined products and the Rodeo Refinery to recover more propane and butane from them than available in their baseline crude slates.

The amount of propane and butane (or its precursors) in the Santa Maria Refinery rail-imported crudes could be substantial, significantly more than in the SMR baseline crude slate, depending upon the specific crudes that are imported. Pressure distillate is the lighter of the two semi-refined products sent to Rodeo. It is mostly naphtha with some material in the kerosene and diesel boiling range. The raw naphtha, for example, can contain significant amount of pentane,[18] which would be recovered at Rodeo by the Propane Recovery Project. Naphtha, for example, is a feed to the proposed LPG[19] Recovery Unit at the Rodeo Refinery. Further, Santa Maria Refinery gas oil is a feed to various hydrocracking units at Rodeo that break it down into recoverable propane and butane feedstocks.

[18] See, for example, Tesoro Material Safety Data Sheet, Naphtha; Available at: http://www.collectioncare.org/MSDS/naphthamsds.pdf.

[19] LPG = Liquefied Petroleum Gas = propane + butane.

The SMR Rail Spur Project RDEIR states that rail-imported crude oils would be sourced from oilfields throughout North America based on market economics and other factors. SMR Rail Spur Project RDEIR, pp. 1-4 & 2-22. The RDEIR identifies two tar sands crudes (RDEIR, pp. 2-3, 4.12-27, Tables 2.6 & 4.3.13, 4.7.14) and admits it has received another for about one year. SMR Rail Spur Project RDEIR pp. ES-14, 4.13-27, 2-31, 2-33, 5-3. While it asserts Bakken crudes will not be imported, the RDEIR does not contain any conditions that restrict the types of crudes that will be imported. Thus, the Santa Maria RDEIR should have evaluated the full range of potential cost-advantaged crudes that could be imported. The crudes that the RDEIR specifically identifies, plus other cost-advantaged crudes available in the market, would increase the amount of propane and butane that could be recovered at the Rodeo Refinery, compared to the SMR baseline. These various crudes are discussed below.

1. <u>DilBit Tar Sands Crudes</u>

The SMR Rail Spur Project RDEIR identifies Access Western Blend[20] and Peace River Heavy[21] as potential crudes that could be delivered via rail and processed at the Santa Maria Refinery. SMR Rail Spur Project RDEIR, pp. 2-3, 4.12-27, Tables 2.6 & 4.3.13, 4.7.14. The RDEIR also admits that SMR has received Canadian tar sands crude oil for about one year (post-baseline), specifically Kearl Lake, which made up 2% to 7% of the processed crude slate. SMR Rail Spur Project RDEIR pp. ES-14, 4.13-27, 2-31, 2-33, 5-3. The RDEIR also asserts that Bakken crudes will not be imported. However, the RDEIR does not contain any conditions that restrict the type of crudes that will be imported. Thus, the RDEIR should have evaluated the full range of potential cost-advantaged crude imported.

Most tar sands crudes are too heavy to flow in a pipeline and to be transported in the type of railcar proposed for the Project (*i.e.*, no steam coils or dedicated steaming facilities at Santa Maria), or unloaded and transferred to on-site storage tanks. Thus, they must be diluted or thinned with a lighter hydrocarbon stream to reduce viscosity. These diluted tar sands crudes are called "DilBits," which is a shorthand expression for blends of **dil**uent and tar sands **bit**umen. All of the tar sands crudes mentioned in the RDEIR are DilBits. A DilBit typically contains 25% to 30%+ diluent. The diluent is typically natural gas condensate, pentanes, or naphtha.[22] Diluent presents two opportunities to increase the amount of propane and butane that could be recovered at Rodeo.

First, chemical composition data for the three tar sands crudes identified in the RDEIR indicates they are loaded with propanes and butanes. Peace River Heavy contains 0.83 vol% butanes and 7.05 vol% pentanes.[23] Access Western Blend contains 0.69 vol% butanes and

[20] http://www.crudemonitor.ca/crude.php?acr=AWB.

[21] http://www.crudemonitor.ca/crude.php?acr=PH.

[22] Gary R. Brierley, Visnja A. Gembicki, and Tim M. Cowan, Changing Refinery Configurations for Heavy and Synthetic Crude Processing, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

[23] http://www.crudemonitor.ca/crude.php?acr=PH.

8.67% propanes.[24] Kearl Lake contains 0.83 vol% butanes and 10.2 vol% propanes.[25] Thus, it is indisputable that the targeted tar sands crude would contribute to the butane and propane that would be recovered by the Propane Recovery Project at Rodeo.

The SMR Rail Spur Project RDEIR alleges these butanes and propanes would be partitioned into the refinery fuel gas at SMR and thus would not reach the Rodeo Refinery. Most of the butane, present in much smaller amounts, could be partitioned to the fuel gas, depending on the temperature cut points of the distillation tower. However, most of the propane would remain in the straight run naphtha produced in the crude tower. SMR Rail Spur Project RDEIR, Fig. 2-10. Thus, the amount of butane and propane remaining in the semi-refined products headed to Rodeo, principally the pressure distillate, would be higher than in the baseline in which only heavy sour crudes were processed. SMR Rail Spur Project RDEIR, pp. 2-31. Further, operation of the crude tower could be modified to incorporate more of the propane and butane into the naphtha fraction.

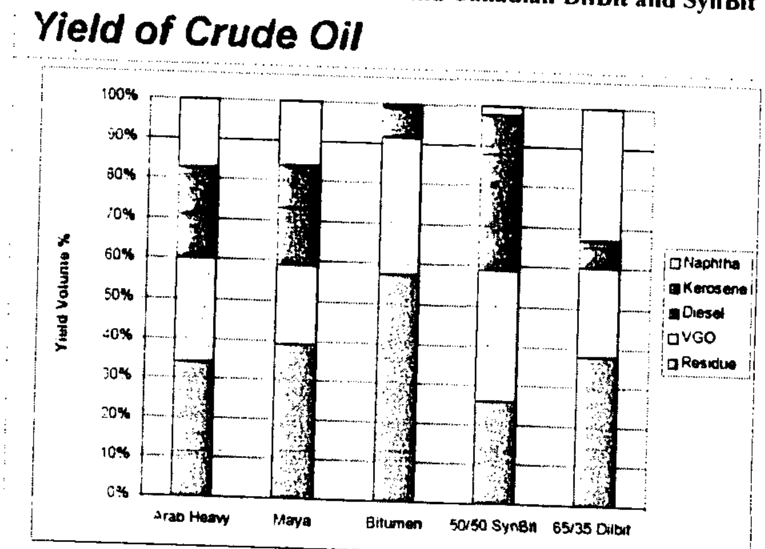
Second, DilBits, when refined, will yield much greater amounts of naphtha,[26] the lighter component of the pressure distillate sent to Rodeo and one of the feedstocks for propane recovery. Propane Recovery Project RDEIR, Fig. 3-6. The higher yield of naphtha from distilling DilBits, compared to heavy crudes, is illustrated in Figure 1. This bar chart compares the output of the distillation column (crude tower) for two commonly refined conventional heavy crudes (Arab Heavy and Maya, which are similar to the Santa Maria Refinery baseline crude slate) and three Canadian tar sands crudes (raw bitumen, SynBit, and DilBit). The last bar in Figure 1, 65/35 DilBit (65% bitumen, 35% diluent) is most similar to the crudes identified in the SMR Rail Spur Project RDEIR. Raw bitumen would be unlikely in large amounts without additional steam support at the proposed rail terminal. The SMR is not designed to refine SynBits so they also are unlikely imports.

[24] http://www.crudemonitor.ca/crude.php?acr=AWB.

[25] http://www.crudemonitor.ca/crude.php?acr=KDB.

[26] N. Yamaguchi, Tight Oil and Oil Sands in the U.S. Crude Slate: What Fuel Marketers Need to Know. Available at: http://fuelmarketernews.com/tight-oil-oil-sands-u-s-crude-slate-fuel-marketers-need-know/.

Figure 1
Distillation Yields of Conventional and Canadian DilBit and SynBit



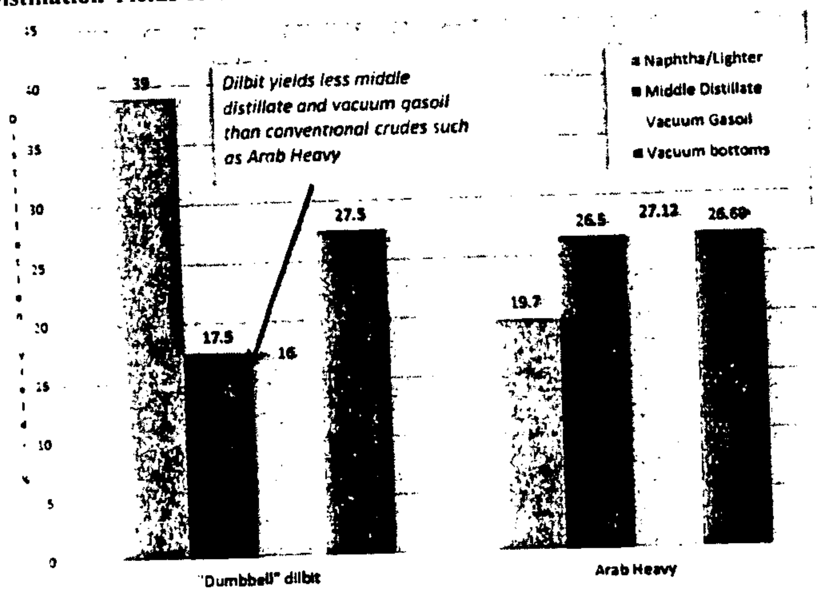
(From: Kevin Turini and others, Processing Heavy Crudes in Existing Refineries, Slides, 2011 AIChe Meeting, Chicago, IL

DilBits are sometimes referred to as "dumbbell" or "barbell" crudes as the majority of the diluent is C_5 to C_{12} and the majority of the bitumen is C_{30}+ boiling range material, with very little in between.[27] This means these crudes have a lot of material boiling at each end of the boiling point curve, but little in the middle. The 65/35 DilBit bar in Figure 1 indicates that these crudes generate about twice as much "naphtha" as the heavy crudes they would replace.

This is further confirmed by a different distillate yield bar chart from another source in Figure 2. This figure likewise confirms that switching from a heavy crude to a DilBit crude would roughly double the amount of naphtha distilled from the crude, from 19.7% to 39% and decrease gas oil from 27% to 16%. Additional amounts of both naphtha and gas oil would be produced by cracking the vacuum bottoms in the coker.

[27] Gary R. Brierley and others, Changing Refinery Configuration for Heavy and Synthetic Crude Processing, 2006; Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

Figure 2
Distillation Yields of a Conventional Heavy Crude (Arab Heavy) and DilBits



Source: Trans-Energy Research
(from: Nancy Yamaguchi, Tight Oil and Oil Sands in the U.S. Crude Slate: What Fuel Marketers Need to Know, Fuel Marketer News; Available at: http://fuelmarketernews.com/tight-oil-oil-sands-u-s-crude-slate-fuel-marketers-need-know/

The DilBits yield very little middle distillate fuels, such as diesel, heating oil, kerosene, and jet fuel and more coke, than other heavy crudes. A typical DilBit, for example, will have 15% to 20% by weight light material, basically the added diluent, 10% to 15% middle distillate, and the balance, >75% is heavy residual material (vacuum gas oil and residue) exiting the distillation column. These characteristics, which distinguish DilBits from the current baseline crude slate, have two major implications.

First, refining of DilBits at SMR will generate more naphtha, the lighter semi-refined product, and less gas oil, thus changing the semi-refined product distribution. The increased amount of naphtha, when processed at the Rodeo Refinery, will generate more propane and butane. Naphtha, for example, is one of the feeds to the proposed LPG Recovery Unit. Propane Recovery Project RDEIR, Fig. 3-6. In other words, the increased amounts of naphtha produced from imported DilBit tar sands (or light tight crudes) would contain higher amount of propane and butane precursors, which would not be partitioned to refinery fuel gas at the Santa Maria Refinery as they would be present in the pressure distillate and refined at the Rodeo Refinery to recover butane and propane.

The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. The average baseline crude throughput for the Santa Maria Refinery (2010-2012) is 38,029 bbl/day. SMR Rail Spur Project RDEIR Table 2.7. Throughput data obtained from the SLOCAPCD indicates that this crude input generated 20,714 bbl/day of gas oil and 11,633 bbl/day of pressure distillate. Exhibit 5. Figures 1 and 2 indicate that DilBits could roughly double the amount of naphtha distilled from the crude oil. Assuming that all of the pressure distillate is naphtha, replacing 37,142 bbl/day of conventional heavy crudes with an equivalent amount of DilBit crude could increase naphtha yield from 11,633 bbl/day to 22,723 bbl/day (37,142/38,029 ×

11,633 × 2 = 22,723) in the baseline and significantly more once the SMR Throughput Project is operating at capacity. This significant increase in naphtha in the pressure distillate sent to Rodeo would allow the recovery of significant additional propane and butane at the Rodeo Refinery, relative to the baseline. This increase in naphtha in the pressure distillate would not exceed any tank vapor pressure limits as all of the tanks are operating far below their limit and the vapor pressure of the naphtha itself and the pressure distillate in which it is present are less than tank vapor pressure limits.

Second, the refining of DilBits at SMR will increase the amount of coke. This would increase emissions from coke dust and truck transport of coke, an impact not disclosed in the SMR Rail Spur Project RDEIR. This is further discussed in Comment III.

2. <u>Other Tar Sand Crudes</u>

The RDEIR also does not exclude the import of heavier tar sands crudes. In general, at refineries with cokers, such as Santa Maria Refinery, even decreases in API gravity (*i.e.*, heavier crude) can result in more propane and butane in the semi-refined products.[28]

3. <u>Light Crudes</u>

Finally, while the RDEIR asserts that Bakken crudes would not be imported (SMR Rail ~~Spur Project RDEIR, pp. ES-5, 1-4, 2-1, 2-22)~~, there are many other cost-advantaged light crudes that could be imported by rail. In general, the lighter the crude, the more butane and propane that can be recovered when it is refined.[29] These include new sources of cost-advantaged North American crudes, such as from the Permian (west Texas), Eagle Ford (south Texas), Granite Wash (Texas Panhandle), and Niobrara (Colorado) basins,[30] as well as Rocky Mountain Sweet (Casper, WY), and Mississippian Lime (Oklahoma).[31] Many of these crudes are already being refined by Phillips 66.[32] These crudes contain significant amounts of propane and butane and their precursors. The RDEIR does not exclude the rail import of any of these light, cost-advantaged crudes.

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[28] NPC North American Resource Development Study, September 15, 2011, p. 18.

[29] See, *e.g.*, NPC North American Resource Development Study, Natural Gas Liquids (NGLs), September 15, 2011, p. 18; Available at: http://www.npc.org/prudent_development-topic_papers/1-13_ngl_paper.pdf.

[30] Dangerous Goods Transport Consulting, Inc., 2014, p. 23 (vol% C2 – C5 in Eagle Ford crude reported as 8.3%); Available at: composhttps://www.afpm.org/WorkArea/DownloadAsset.aspx?id=4229.

[31] Alan Mazaud, Exergy Resources, May 23, 2013, Pennsylvania Rail Freight Seminar, Slide: Growth of Domestic Production of Tight Oil.

[32] Phillips 66 Third Quarter Conference Call Slides, October 29, 2014; Available at: http://investor.phillips66.com/files/doc_presentations/2014/Earnings/PSX-Q3-News-Release-Slides-FINAL_v001_k94fx2.pdf.

4. Other Sources of Propane/Butane

The gas oils and naphthas sent to Rodeo would be further refined. This refining itself produces propane and butane. For example, the pressure distillate would be fed to hydrotreaters and hydrocrackers, which would produce propane- and butane-rich streams. The gas oils would be feed to cokers and hydrotreaters, which would also produce propane- and butane-rich streams. Thus, the increased amount of propane and butane that could be recovered when these semi-refined products generated from a lighter crude slate are further refined at Rodeo. Additional propane and butane could be generated at Rodeo itself by switching to a lighter crude slate.

D. Summary

In sum, the claims made in the RDEIRs in an attempt to decouple the Santa Maria Refinery Rail Spur Project and the Rodeo Refinery Propane Recovery Project based on vapor pressure limits have no merit. Some of the tanks have no vapor pressure limits at all, as vapors are recovered. All of the tanks operate far below their permitted vapor pressure limits. Further, the pipeline is operated to send semi-refined materials directly to Rodeo, without interim storage in pump station tanks along the pipeline. Even if semi-refined products had to be offloaded, their vapor pressures are far below permit limits. Thus, there is ample head room to increase the vapor pressure of semi-refined products shipped from Santa Maria to Rodeo.

III. EMISSIONS ARE UNDERESTIMATED

The SMR Rail Spur Project RDEIR estimated emissions from locomotives, fugitive emissions from railcars, pipeline components and crude oil storage tanks, a vapor recovery carbon canister, and vehicle traffic. SMR Rail Spur Project RDEIR, Sec. 4.3.4.2 & Appx. B. However, it omitted other sources of emissions, discussed below.

The SMR Rail Spur Project is proposing to replace the **majority** of the current crude slate (2010-2012: 38,100 bbl/day) with up to 100% tar sands crudes. The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. SMR Rail Spur Project RDEIR, p. 2-23. Thus, the Project would replace 97% of the baseline crude slate with up to 100% tar sands crude. The Throughput Increase Project will increase the crude permit level to 48,950 bbl/day. SMR Throughput Increase FEIR, p. 1-1. Thus, at full buildout, up to 76% of the crude slate will be different crudes than in the baseline, potentially 100% tar sands crudes. These new crudes have many chemical and physical properties that distinguish them from the baseline crude slate and that will result in impacts that were not evaluated in the SMR Rail Spur Project RDEIR. These were discussed for both tar sands and light crudes in my previous comments in Exhibits 2 and 3, which are incorporated here by reference.

A. Emission Changes Due To Changes in Fuel Gas Composition

The SMR Rail Spur Project RDEIR asserts that if significant amounts of propane and butane were present in the imported crudes, as discussed in Comment II, they would be partitioned into the Santa Maria refinery fuel gas. Assuming, *arguendo*, that this is correct, it would significantly increase the heat content of the refinery fuel gas. This would have several impacts. First, combustion temperatures would be higher in all heaters and boilers, as propane and butane burn with a hotter flame than natural gas and baseline refinery fuel gas, not enriched with propane and butane.[33] This would increase emissions nitrogen oxides (NOx) from all refinery fuel gas fired sources, compared to the baseline. Second, propane and butane have higher GHG global warming potentials than other components in refinery fuel gas.[34] Thus, greenhouse gas emissions from all heaters and boilers would increase. Finally, the significant increase in heat content may require modification or replacement of existing burner in heaters and boilers. None of these impacts were addressed in the SMR Rail Spur Project RDEIR.

B. Increased Combustion Emissions from Tar Sands Bitumen Not Evaluated

The SMR Rail Spur Project RDEIR indicates that tar sands crudes will be imported. The composition of tar sands crudes is chemically different from other heavy crudes currently processed at the SMR as they are tar sands bitumen mixed with diluent. They are unique for two major reasons: (1) presence of large quantities of volatile diluent full of reactive organic gases (ROG) and toxic chemicals as discussed above and (2) unique chemical composition of the bitumen, the heavy fraction. The previous comment discussed diluent, which will modify the composition of the both the semi-refined products sent to the Rodeo Refinery and the SMR refinery fuel gas. This comment discusses the unique composition of tar sands bitumens that require more intense processing and thus result in higher emissions.

Tar sands bitumens are composed of higher molecular weight chemicals and are deficient in hydrogen compared to conventional heavy crudes. This means more energy will be required and more emissions produced to convert them into the same slate of semi-refined and refined products. More energy will be required to add hydrogen and break the bonds of the larger molecules.

The SMR Rail Spur Project RDEIR concedes the hydrogen point. However, the SMR Rail Spur Project RDEIR argues that hydrogen addition occurs at the Rodeo Refinery, not at the Santa Maria Refinery, and thus did not include these emissions. SMR Rail Spur Project RDEIR, pp. 4.3-69/70. However, as explained in my comments in Exhibits 2 and 3 and comments by others on the SMR Rail Spur Project RDEIR (Pless 2014[35]; Karras 2014), the Rodeo Refinery Propane Recovery Project and the SMR Rail Spur Project should have been evaluated under CEQA as a single project as they depend on each other. Thus, the increase in emissions of criteria pollutants and greenhouse gases from most fired sources due to tar sands bitumen derived semi-refined products refined at the Rodeo Refinery should have been included in the emission inventory for the SMR Rail Spur Project.

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[33] Flame Temperatures of Some Common Gases; Available at: http://www.engineeringtoolbox.com/flame-temperatures-gases-d_422.html.

[34] See, *e.g.*, http://www.epa.gov/climateleadership/documents/emission-factors.pdf.

[35] Letter from Petra Pless to Laura Horton, Re: *Review of the Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report and Vertical Coastal Access Project Assessment*, November 21, 2014.

The Rodeo Refinery RDEIR is silent as to other crude quality factors that will increase emissions at Rodeo. Canadian tar sands bitumen is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular weight polymeric material.[36] Crudes derived from Canadian tar sands bitumen – DilBits, SCOs and SynBits – are heavier, *i.e.*, have larger, more complex molecules such as asphaltenes and resins,[37] some with molecular weights above 15,000.[38] They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[39] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker, which would occur at the Santa Maria Refinery. They require more intense processing in the coker to break them down into lighter products.

These differences are not reflected in any of the lumper parameters (API gravity, vacuum resid percentage, sulfur, TAN) presented in the SMR Rail Spur Project RDEIR. SMR Rail Spur Project Table 4.3-13 and p. 4.3-70. These differences mean that the coker at the Santa Maria Refinery will have to work harder to convert vacuum bottoms from distilling tar sand crude into gas oil, which will increase combustion emissions of NOx, sulfur oxides (SOx), carbon monoxide (CO), ROG, particulate matter with an aerodynamic diameter of 10 and 2.5 micrometers or less (PM10 and PM2.5), and greenhouse gases (GHGs). These increases in emissions were not included in the emission inventory.

C. Increased Metal Content from Tar Sands Were Not Evaluated

The Project could increase the import of heavy sour tar sands crude by up to 76% of the entire permitted capacity of the Santa Maria Refinery, once the SMR Throughput Project is fully operational. These crudes have higher metal content than the baseline crude slate.[40] This represents a significant increase in a type of crude that will increase emissions compared to the

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

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

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

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

[40] Straatiev and others, 2010. Table 1; Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils; http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF; F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010; Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf.

current Refinery slate. The impacts from this change were not evaluated in the SMR Rail Spur Project RDEIR.

The U.S. Geological Survey (USGS) reported that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil, such as those currently refined from local sources.[41] The SMR Rail Spur Project RDEIR reported vanadium and nickel concentration in a current "typical crude blend" compared to two potential tar sands crudes. SMR Rail Spur Project RDEIR, Table 4.3-13. This comparison shows that the vanadium concentration in Access Western Blend (190 ppmw) and Peak River Heavy (167 ppmw) are higher than the upper end of the range of major baseline crude sources. The SMR Rail Spur Project RDEIR is silent as to the significance of this reported increase in vanadium. The SMR Rail Spur Project RDEIR did not present any data for any other metal, known to be elevated in tar sands crudes.

The environmental damage caused by these metal pollutants includes bioaccumulation of toxic chemicals up the food chain and a direct health hazard from air emissions. These metals, for example, mostly end up in the coke. Thus, higher levels of metals will be present in the coke dust and coke pile runoff/seepage. The SMR Rail Spur Project DEIR indicated that "[m]etals that are present in coke have been detected in groundwater at concentrations above the California Department of Health maximum contamination levels (MCL) in the area around the coke pile runoff area..." SMR Rail Spur Project DEIR, p. 4.7-39/40. This statement has vanished from the SMR Rail Spur Project RDEIR. Thus, a switch to tar sands crude could contribute to this existing significant impact from the coke pile, which was not disclosed in the SMR Rail Spur Project RDEIR.

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

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

D. Sump Emissions Were Omitted

Unloading facilities generally include liquid spill containment sumps with the capacity to contain the contents of at least one tank car. Crude oil that spills into these sumps would release vapors including ROG, which are ozone precursors, and toxic air contaminant (TAC) emissions. The RDEIR is silent as to sumps and their emissions.

E. Rail Car Fugitive Emissions Were Omitted

ROG and TACs are emitted from rail cars from their point of origin through unloading as rail cars are not vapor tight. The SMR Rail Spur Project RDEIR did not include these emissions.

The crude oil would be shipped in tank cars, such that the volume of loaded crude oil shipped is less than the capacity of the rail car to accommodate expansion during shipping. This volume reduction creates free space at the top of the tank car, which provides space for entrained gases, such as those from diluent, to be released from the crude oil[42] and emitted to the atmosphere during transit and idling in rail yards.[43]

As rail cars are not vapor tight, these vapors in the head space above the oil are emitted to the atmosphere during rail transport and at the unloading terminal. The vapor in the headspace can flash during transport, when temperature increases or pressure drops, causing valves to open, emitting ROG and TACs.

These losses are consistent with the well-known "crude shrinkage" issue associated with crude by rail. The crude delivered is significantly less than the crude loaded. The reported range in crude shrinkage is 0.5% to 3% of the loaded crude.[44] Some of this shrinkage is likely due to emissions from the rail car during transit. The emissions of ROG and TACs from rail cars has been confirmed by field measurements.[45] The SMR Rail Spur Project RDEIR did not include these ROG and TAC emissions in its emission calculations or the health risk assessment.

Tank cars have domes to allow space for the product to expand as temperatures rise. Each dome has a manhole through which the tank car can be loaded, unloaded, inspected, cleaned, and repaired. Dome covers may be hinged and bolted on or screwed on. Most domes

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[42] Anthony Andrews, Congressional Research Service, Crude Oil Properties Relevant to Rail Transport Safety: In Brief, February 18, 2014, pp. 8-9.

[43] A DOT 111 (or comparable) tank car generally has a capacity of 34,500 gallons or 263,000 lbs. gross weight on rail. Under some conditions, the maximum gross weight can be increased to 286,000 lbs. At an API gravity of 50°, a tank car can hold its maximum volume of 31,800 gallons and not exceed the 286,000 lb gross weight on rail limit. As the API gravity drops, the amount of oil that can be carried must also drop. Thus, a tank car of Bakken crude, at its highest density of 39.7° API, can only hold 30,488 gallons, a volume reduction of about 1,300 gallons. Further, as crude oil density (and thus API gravity) is temperature dependent, volume will increase as temperature increases. Thus, the shipper may have to reduce the shipped volume even further. This volume reduction creates a space above the crude oil where vapors accumulate.

[44] Alan Mazaud, Exergy Resources, Pennsylvania Rail Freight Seminar, May 23, 2013, p. 17. Available at: http://www.parailseminar.com/site/Portals/3/docs/Alan%20Mazaud%20Presentation%20-%20AM.pptx

[45] http://www.youtube.com/watch?v=35uC1gLctmw.

have vents and safety valves to let out vapors.[46] Thus, they are sources of ROG emissions that were omitted from the emission calculations. Further, when dome covers are left open, any residual vapors escape to atmosphere. Residual material clings to the bottom and sides of empty rail cars and emits ROG and TACs while the rail cars idle at the site, waiting for the entire unit train to be unloaded. Open covers are common in rail yards as they are opened for inspections and repairs. The ROG and TAC emissions from these sources were not included in the SMR Rail Spur Project RDEIR's emission inventory.

Further, each tank car has a bottom outlet which is used for loading and unloading that includes pumps, manifolds, and valves, all of which leak ROG and TACs. Finally, liquid leaks occur when unloading arms are disconnected, even with state-of-the-art no leak arms. These disconnect leaks evaporate, contributing to ROG and TAC emissions.

An estimate of these emissions can be based conservatively on the lower end of the range of crude shrinkage (0.5%) discussed above and the maximum freight weight per car of 106 tons from the TRN Spec Sheet-1. Assuming 80 cars/train and five unit trains per week (SMR Rail Spur Project RDEIR, p. ES-5), a total of 30 ton/day[47] of ROG can be emitted as the trains travels from Canada to the Santa Maria Refinery rail terminal. The distance travelled outside of California was not reported, but is estimated to be about 1500 miles. The distance within California, on the longest route, is estimated as 300 miles one way. SMR Rail Spur Project RDEIR, p. B-9. Thus, about 17% of the 30 ton/day of ROG would be emitted in California or about 5 ton/day of ROG (10,000 lb/day) can be emitted within California from rail car leakage.[48] Of the 300 miles within California, 67 miles are within the boundary of the SLOCAPCD via the northern route. SMR Rail Spur Project RDEIR, p. B-9. Thus, 1.1 ton/day (2,200 lb/day) of ROG emissions can be emitted within the SLOAPCD from rail car leakage.[49] These daily emissions greatly exceed the SLOCAPCD daily ROG+NOx CEQA significance threshold of 25 lb/day (RDEIR, Table 4.3-17), requiring additional mitigation not identified in the RDEIR. These ROG emissions could be reduced by modifying the rail cars before they are shipped to minimize or eliminate leakage.

These ROG emissions contain the same chemicals found in the crude oil, including benzene, toluene, ethylbenzene, and xylene (collectively "BTEX") and hexane. Some crudes can contain up to 7% benzene by weight. Thus, greater than 154 lb/day of benzene could be emitted in California from rail car leakage. This rail car leakage is much greater than the amount of benzene (and other TACs) included in the SMR Rail Spur Project RDEIR's health risk assessment.

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[46] Chapter 11. Tank Car Operations, Available at: http://www.globalsecurity.org/military/library/policy/army/fm/10-67-1/CHAP11.HTML.

[47] ROG emissions from train transit = (106 ton/car)(80 car/train)(5 train/week)(0.005)/(7 days/week) = **30 ton/day.**

[48] ROG emitted within California = (30 ton/day)(300/1500+300) = **5 ton/day.**

[49] ROG emitted within SLOCAPCD = (30 ton/day)(67/1500+300) = **1.1 ton/day.**

IV. THE SMR RAIL SPUR PROJECT RDEIR DID NOT EVALUATE THE INCREASE IN RISK OF ACCIDENTS AT THE SANTA MARIA REFINERY

The SMR Rail Spur Project RDEIR includes a brief discussion of the impact of changes in crude slate on hazards at the Refinery, designated as Impact #HM.3. SMR Rail Spur Project RDEIR pp. 4.7-63 and 4.7-65. This discussion touches on naphthenic acid corrosion, pointing to various inspection programs and ultimately dismissing corrosion-related accidents because "... the expected range of sulfur and TAN would be within the range of the crudes that are currently being processed at the SMR. Therefore, the change in crude slate would not be expected to change the sulfur or TAN levels compared to the crude sources that are currently being processed at the SMR." SMR Rail Spur Project RDEIR, Table 4.7-14 and p. 4.7-66. This is an inadequate discussion and the conclusions are wrong for several reasons.

First, corrosion failures in refineries are of great concern because of the high likelihood of "blowout" or catastrophic failure of components. This can happen because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it bursts, rather than leaking at a pit or local thin area that could be found during visual inspections. The process fluids carried in these lines are often above their auto-ignition temperature, resulting in large fires. They also usually carry toxic and hazardous materials, such as sulfur compounds (hydrogen sulfide, mercaptans, benzene) that can lead to toxic clouds, which can have significant adverse effects on surrounding communities.

Second, as background, it is important to recognize that the Rail Spur Project is proposing to replace the **majority** of the current crude slate (38,100 bbl/day) with up to 100% tar sands crudes. The Project proposes to import 37,142 bbl/day of cost-advantaged crudes by rail. SMR Rail Spur Project RDEIR, p. 2-23. Thus, the Project would replace 97% of the baseline crude slate with up to 100% tar sands crude. The SMR Throughput Increase Project will increase the crude permit level to 48,950 bbl/day. SMR Throughput Increase Project FEIR, p. 1-1. Thus, at full buildout, up to 76% of the crude slate will be different crudes than in the baseline, potentially 100% tar sands crudes.

Third, tar sands crudes have high Total Acid Numbers (TAN),[50] which indicates high organic acid content, typically naphthenic acids. Naphthenic acid attack occurs primarily in crude units and vacuum units, such as those at the SMR. SMR Rail Spur Project RDEIR, Fig. 2-10. They also form sludge and gum which can block pipelines and pumps. However, some acids are relatively inert. Thus, the TAN number does not always represent the true corrosive properties of a crude oil. Further, different acids will react at different temperatures, making it difficult to determine which processing units may be affected. As a rule-of-thumb, crude oils with a TAN number greater than 0.5 mg KOH/g are considered to be potentially corrosive and indicates a level of concern. A TAN number greater than 1.0 mg KOH/g is considered to be very high.[51] Canadian tar sands crudes are very high TAN crudes. The DilBits,

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

[51] Margaret Sheridan, California Crude Oil Production and Imports, Staff Paper, California Energy Commission, April 2006, p. 6; Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF.

for example, range from 0.98 to 2.42 mg KOH/g.[52] The Project is proposing to import crudes at the upper end of this range (SMR Rail Spur Project RDEIR, Table 4.7.14), far above the level of concern and far above the "typical crude blend" refined at SMR in the baseline. SMR Rail Spur Project RDEIR, Table 4.7-14. Thus, the RDEIR should have included a detailed analysis of the corrosion potential of the proposed crude slate and imposed mitigation.

Further, while the industry benchmark for TAN corrosion is 0.5, crudes with lower TANs can still cause significant corrosion problems, depending upon the specific acids. Sweet low TAN crudes, such as those currently flooding the market, and which could be imported by the Rail Spur Project, are also known to cause TAN corrosion.[53] The SMR Rail Spur Project RDEIR is silent on corrosion issues related to these crudes.

Fourth, each crude has its own unique characteristic chemistry and thus effects on corrosion. Refineries that process a consistent diet of a particulate crude or crude blend can base future predictions of corrosion potential on past experience. However, when a major switch in crude slate occurs, as proposed here, predicting future corrosion based on historic operating ranges or "typical crude blends", as in the SMR Rail Spur Project RDEIR, is not reliable. A new slate, even when major lumper parameters are in the historic range, minimizes the accuracy, or even the feasibility of predictions based on historic data.[54]

The rationale that sulfur levels and TAN of the crude slate would stay within the reported range and thus corrosion is not an issue, ignores the possibility of gradual creep in both sulfur and TAN within the usual range that could still be significant. The SMR Rail Spur Project RDEIR, for example, concedes that the new crude slate would increase sulfur by 0.8%. SMR Rail Spur Project RDEIR, p. 4.3-46. From a corrosion standpoint, this is a significant increase. The SMR Rail Spur Project RDEIR did not discuss the impact of a 0.8% increase in sulfur on corrosion-induced accidents at the SMR.

The high proportion of tar sands crudes in the future crude slate renders the ranges in SMR Rail Spur Project RDEIR Table 4.7-14 as irrelevant for concluding that the new crudes fall within the range of historic crudes. For example, if 100% Peace River Heavy[55] were refined, both its average sulfur and TAN level would exceed the sulfur (5.0%>4.2%) and TAN (2.5>1.0 mg KOH/g) concentrations in the baseline "typical crude blend." In fact, even the lower end of the reported range of sulfur and TAN in Peace River Heavy would exceed the "typical crude blend." The fact that the sulfur and TAN of Peace River Heavy falls within the reported ranges (S: 2.1 to 5.2%; TAN: 0.4-4.0 mg KOH/g) is simply irrelevant, as the SMR did not operate, on average, at the upper end of the range. Because the sulfur and TAN data for

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[52] www.crudemonitor.ca.

[53] M.J. Nugent, J.D. Dobis, Experience with Naphthenic Acid Corrosion in Low TAN Crudes, Corrosion 98, Paper No. 577

[54] See discussion in API Recommended Practice 939-C, Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failure in Oil Refineries, First Edition, May 2009.

[55] Access Western Blend (TAN: 1.69-1.85 mg KOH/g; S: 3.94-3.96%): http://www.crudemonitor.ca/crude.php?acr=AWB and Peace River Heavy (TAN: 2.42 to 2.58 mg KOH/g; S: 4.94 to 5.08%): http://www.crudemonitor.ca/crude.php?acr=PH.

these tar sands crudes exceed the "typical crude blend" by significant amounts, corrosion impacts are significant and should have been disclosed, analyzed, and mitigated.

Fifth, the SMR Rail Spur Project RDEIR did not discuss or even mention sulfidation corrosion, which is a concern for refineries such as SMR, built in 1955 before current American Petroleum Institute (API) standards were developed to control corrosion and before piping manufacturers began producing carbon steel in compliance with current metallurgical codes. Rather, it notes in passing that "[h]igh sulfur levels can lead to sulfide related corrosion." SMR Rail Spur Project RDEIR, p. 4.7-65.

The early construction date suggests the metallurgy used throughout much of the SMR may not be adequate to handle the unique chemical composition of tar sands crudes without significant upgrades. There is no assurance that required metallurgical upgrades would occur if tar sands crudes dominate the crude slate, as they are very expensive and are not required by any regulatory framework. Experience with changes in crude slate at the Chevron Refinery in Richmond in the San Francisco Bay Area suggest required metallurgical upgrades are ignored, leading to catastrophic accidents.[56]

Sulfidation corrosion generally occurs above about 500 F for carbon steel pipe and above about 600 F for 5 Cr low-alloy steel. Some sulfide species are more corrosive than others, including mercaptans, hydrogen sulfide, and disulfides, all of which occur at elevated levels in tar sands crudes. Sulfidation corrosion manifests as uniform thinning and thus cannot be detected from visual inspections. Low silicon carbon steel can corrode 2 to 10 times faster than higher silicon carbon steel.[57]

How much low silicon carbon steel piping is present at SMR? What impact will an admitted 0.8% increase in sulfur have on this piping? What sulfur compounds are present in the 0.8% increase in sulfur? The SMR Rail Spur Project RDEIR did not disclose either the specific suite of sulfur compounds in the proposed imports or the metallurgy and operating conditions in the units potentially susceptible to sulfidation corrosion. Thus, it fails as an informational document under CEQA.

A catastrophic blowout due to sulfur creep recently occurred at the Chevron Richmond Refinery near the Rodeo Refinery. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit.[58] This change increased corrosion rates in the 4-sidecut line, which led to a

[56] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013; Available at: http://www.csb.gov/chevron-refinery-fire/.

[57] E.H. Niccolls, J.M. Stankiewicz, J.E. McLaughlin, and K. Yamamoto, High Temperature Sulfidation Corrosion in Refining, September 2008, 17th International Corrosion Congress, Corrosion Control in the Service of Society, Vol. 1 of 5, as cited in: Interim Investigation Report, Chevron Richmond Refinery Fire, August 6, 2012; Available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf.

[58] US Chemical Safety and Hazard Investigation Board, Chevron Richmond Refinery Pipe Rupture and Fire, August 6, 2012, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of

catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This accident sent 15,000 people from the surrounding area for medical treatment due to the release and resulting fire that created huge black clouds of pollution billowing over the surrounding community and across the San Francisco Bay.[59]

The SMR has a similar crude unit, identified as the "crude tower" in SMR Rail Spur Project RDEIR Figure 2-10. These types of accidents can be reasonably expected to result from incorporating tar sands crudes into the Santa Maria Refinery crude slate, even if the range of sulfur and TAN of the crudes remain the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentrations of sulfur in the heavy components of the crude coupled with high total acid numbers (TAN) and high solids, which aggravate corrosion. A crude slate change could result in corrosion from, for example, the particular suite of sulfur compounds or naphthenic acid content, that leads to significant accidental releases, even if the crude slate is within the current design slate basis, due to compositional differences. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from refining 76% to 97% tar sands crudes, leading to catastrophic releases.[60]

Elevated levels of TAN and sulfur can cause accidents that result in catastrophic releases of air pollution. Such releases were not considered in the SMR Rail Spur Project RDEIR. Rather, the SMR Rail Spur Project RDEIR relies on the SMR's existing Process Safety Management program, including the Management of Change (MOC) and Mechanical Integrity (MI) programs, to prevent corrosion. SMR Rail Spur Project RDEIR, pp. 4.7-65/66. However, these programs were also in place at the Chevron Richmond Refinery (and many other similarly afflicted refineries) at the time of the August 2012 accident discussed above. They did not prevent a catastrophic accident caused by sulfur (or TAN) creep. The recent Chevron Refinery Modernization Project FEIR incorporated many additional mitigation measures to improve these programs,[61] which should be required for the Santa Maria Refinery to mitigate the increase in sulfur and TAN in crudes imported by the Rail Spur Project.

Refinery emissions released in upsets and malfunctions can, in some cases, be greater than total operational emissions recorded in formal inventories. For example, a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were

the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").

[59] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013, Available at: http://www.csb.gov/chevron-refinery-fire/.

[60] See, for example, K. Turini, J. Turner, A. Chu, and S. Vaidyanathan, Processing Heavy Crudes in Existing Refineries. In: Proceedings of the AIChe Spring Meeting, Chicago, IL, American Institute of Chemical Engineers: New York, NY, Available at: http://www.aiche-fpd.org/listing/112.pdf.

[61] See, for example, Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1 and 2, p. 4-40, Mitigation Measure 4.13-7h, Available at: http://chevronmodernization.com/project-documents/.

frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.[62]

Catastrophic releases of air pollution from these types of corrosion-caused accidents were not considered in the SMR Rail Spur Project RDEIR and are significant. Mitigation should be imposed, including at least the following:

- All mitigation measures required in the Chevron Refinery Modernization Project FEIR;
- 100% component inspection of all carbon steel piping systems susceptible to sulfidation corrosion; and
- Modification of work processes for review of damage mechanisms for processes covered by the Process Safety Management standard to conform with the American Petroleum Institute Recommended Practice 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry. The revised work processes shall require consideration of damage mechanism reviews as part of the Process Hazard Analysis process.[63]

V. RAIL ACCIDENTS WERE UNDERESTIMATED AND ARE SIGNIFICANT

The RDEIR evaluated "potential public safety and hazardous materials impacts" from train derailments and unloading accidents that could lead to fires and explosions. RDEIR, Sec. 4.7. Elsewhere, the RDEIR evaluates the impacts of derailments on water resources and biological resources. RDEIR, Secs. 4.4 & 4.13. These analyses are fundamentally flawed and incomplete, as explained below.

First, the RDEIR only analyzed impacts from the Roseville and Colton Rail Yards to the Project site. It did not analyzed impacts from the California border to these rail yards, arguing that trains could enter California at five different locations and thus the specific route was "speculative". RDEIR, pp. 4.7-1, 4.13-7. Routes are not "speculative" when they are known, as here. The trains can take any of them, depending on conditions. As they are known and any of these known routes can be taken, they are not speculative. The RDEIR should have evaluated all of them. Further, the trains can take multiple routes from the rail yards to the Santa Maria Rail Yard. The RDEIR, inconsistently, did not conclude that this rendered these routes speculative.

This is a serious omission as the segments from the state line to the rail yards pass through some of the state's most sensitive ecological areas and parallel the water supply for most of the state. These route segments also contain many high hazard areas for derailments.

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

[63] Terms and Conditions of Probation, People v. Chevron U.S.A. Inc., Superior Court of the State of California, County of Contra Costa, Case No. 1-162745-4.

Emergency response teams have generally good coverage in the urban areas, but none are located near the high hazard areas in rural Northern California that the RDEIR did not analyze.[64]

Second, the RDEIR did not analyze a worst case derailment. The RDEIR assumed a worst-case spill of 180,000 gallons, or about six tanker cars. RDEIR, p. 4.7-47. No support was provided for this choice. Rail accident records should have been reviewed to select a worst-case spill. The July 2013 Lac-Mégantic derailment spilled about 1.6 million gallons of Bakken crude oil, or about 53 railcars, covering an area of 77 acres.[65] The RDEIR should have based its analysis on a spill of at least 1.6 million gallons.

Third, the RDEIR did not analyze the impacts of a derailment on the state's water supply, which originates in the northern portion of the state along the rail segments eliminated from its analysis as "speculative". The rail routes from the state line to the rail yards parallel major rivers, such as the Sacramento, Yuba, Feather and American Rivers, which supply most of the water used throughout the state, distributed by a complex system of reservoirs and pipelines operated by Central Valley Project and the State Water Project. A significant spill of crude oil into any of these rivers would potentially shutdown the water supply for a significant portion of the state. This would have catastrophic and far reaching consequences that the RDEIR does not acknowledge, let alone analyze.

Fourth, the RDEIR notes that when spilled, a DilBit will sink (RDEIR, 4.13-27), but the RDEIR fails to disclose the resulting consequences on water supply and biological resources. The RDEIR is also silent on the difficulty of cleaning up the spill. An oil pipeline burst near Marshall, Michigan in July 2010, spilling a million gallons of DilBit in the Kalamazoo River. This spill decimated Talmadge Creek, a tributary to the Kalamazoo River, and about 40 miles of the river, prompting a more than $1 billion cleanup that, four years later, is still under way.[66] While most conventional crudes float on water, most of the DilBit, the bitumen component, sinks and clings to bottom sediments. This submerged oil is significantly harder to cleanup. The Kalamazoo spill, which occurred in 2010, is still not cleaned up.[67] The RDEIR failed to disclose

[64] Interagency Rail Safety Working Group, State of California, Oil by Rail Safety in California. Preliminary Findings and Recommendations, June 10, 2014.

[65] NTSB, Safety Recommendation In reply refer to: R-14-4 through -6; January 21, 2014. Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

[66] Keith Matheny, Environmental Disasters Lurk in Energy Pipelines. Detroit Free Press, October 12, 2014. Available at: http://www.freep.com/story/money/business/michigan/2014/10/12/energy-environmental-threats/17046063/.

[67] A Dilbit Primer: How It's Different from Conventional Oil, Inside Climate News. Available at: http://insideclimatenews.org/news/20120626/dilbit-primer-diluted-bitumen-conventional-oil-tar-sands-Alberta-Kalamazoo-Keystone-XL-Enbridge?page=show; Lindsey Smith, 3 Years and Nearly $1 Billion Later, Cleanup of Kalamazoo River Oil Spill Continues, Michigan Radio, July 25, 2013. Available at: http://michiganradio.org/post/3-years-and-nearly-1-billion-later-cleanup-kalamazoo-river-oil-spill-continues; NOAA Office of Response and Restoration, As Oil Sands Production Rises, What Should We Expect at Diluted Bitumen (Dilbit) Spills?, Available at: http://response.restoration.noaa.gov/about/media/oil-sands-production-rises-what-should-we-expect-diluted-bitumen-dilbit-spills.html; Witt O'Brien, A Study of Fate and Behavior of Diluted Bitumen Oils on Marine Waters, November 2013, Available at: http://www.transmountain.com/uploads/papers/1391734754-astudyoffateandbehaviourofdilutedbitumenoilsonmarinewater.pdf

the difficulty of cleaning up a large spill in one of California's headwater rivers that supply California's municipal, industrial, and agricultural water.

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Sent: Tuesday, September 03, 2013 2:05 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project

Our Crude buyer calls it AWB crude. It is from Canada. All three of the manifest cars were from the same supplier.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Tuesday, September 03, 2013 2:02 PM
To: Matthews, John W
Subject: [EXTERNAL]RE: RE: AI Request for crude tanks project

Sorry, I meant geographic origin or other identifier, (similar to California or San Joaquin Valley or Canada), just to identify that column as different and not an average of the others). (Danny was asking for an additional identifier)

From: Matthews, John W [mailto:John.Matthews@p66.com]
Sent: Tuesday, September 03, 2013 1:59 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project

The table was for the proposed crude tank. The crude speciation for the manifest cars was based on three discrete vapor samples taken directly from the representative manifest cars currently being received. The results of the individual samples are in the second, third and fourth columns. The labels on the top of those columns are the DOT numbers of the sampled railcars. The vapor samples were analyzed by EPA Method TO-15.

The maximum from these crude vapor samples (the fifth column) were used in the hybrid speciation.

John W. Matthews, P.E.
Environmental Engineer
Phillips 66 Los Angeles Refinery
(310) 952-6213
john.matthews@p66.com

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Tuesday, September 03, 2013 11:25 AM
To: Matthews, John W
Subject: [EXTERNAL]FW: RE: AI Request for crude tanks project

Hi John,

In the attached table, there are columns for SJV crude, "crude oils", Cal crude, and crude hybrid. What is the origin of "crude oils"?

Janice

From: Marcia Baverman [mailto:mbaverman@envaudit.com]
Sent: Tuesday, February 05, 2013 1:58 PM
To: Matthews, John W (P66)

Cc: mchoi@envaudit.com
Subject: [EXTERNAL]RE: AI Request for crude tanks project

John –

Attached is the derivation of the "hybrid" speciation used to calculate the emissions in the EPA Tanks 4.0 model. The hybrid speciation is the highest concentration for each TAC from each of the three crude speciations used in the most recent AB2588 HRA. The hybrid speciation allows for only having to run one scenario to determine the TAC emissions for use in the HRA.

Thanks -

Marcia Baverman
Project Manager
714-632-8521 ext. 237
mbaverman@envaudit.com

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From: Matthews, John W (P66) [mailto:John.Matthews@p66.com]
Sent: Tuesday, January 15, 2013 10:24 AM
To: 'MBaverman@EnvAudit.com'
Subject: FW: AI Request for crude tanks project

As discussed.

From: Janice West [mailto:jwest@aqmd.gov]
Sent: Thursday, January 10, 2013 1:49 PM
To: Matthews, John W (P66)
Subject: [EXTERNAL]AI Request for crude tanks project

Hi John,

As I mentioned on the phone, I am requesting additional information in support of your crude tanks applications Please provide the following information:

- Details on the speciation of crude oil (the toxics speciation you used in your TANKS calculations), as well as the origin of this speciation and why you feel it is the worst-case scenario for toxics.
- The true vapor pressure limit you are willing to accept for the operation of these tanks (emissions will be recalculated)
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- Information on the impact of the project on the benzene stripper (particularly fugitive counts), and your justification for why an additional application is not needed for that permit unit.

Paul, Tran and I met with Jay yesterday, and after our discussion, Jay instructed me to consider the existing tanks as post-NSR tanks, based on the information in the files, as well as the presence of a throughput limit. I will be re-calculating the baseline emissions using the Tanks program (and the parameters specified in the original permit to operate application), so that the calculation method is the same for pre- and post-project emissions.

Please let me know if you have any comments or questions. I'll wait to proceed until I hear from you.

Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Janice West

From: Matthews, John W [John.Matthews@p66.com]
Sent: Tuesday, September 03, 2013 1:59 PM
To: Janice West
Subject: RE: RE: AI Request for crude tanks project
Attachments: Speciation Data.pdf

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Marcia Baverman
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Thanks,

Janice West
Air Quality Engineer
South Coast Air Quality Management District
909 396-3763
jwest@aqmd.gov

Comments

on the

Draft Environmental Impact Report (DEIR)

for the

Valero Benicia Crude by Rail Project

Benicia, California

September 15, 2014

Phyllis Fox, Ph.D., QEP, PE, DEE
745 White Pine Ave.
Rockledge, FL 32955
phyllisfox@gmail.com
321-626-6885

I have reviewed the Draft Environmental Impact Report (DEIR)[1] for the Valero Benicia Crude by Rail Project (CBR Project) prepared for the City of Benicia (City) by ESA, as well as records referenced in the DEIR and files obtained from the Bay Area Air Quality Management District (BAAQMD).

The CBR Project will install facilities to allow the Valero Benicia Refinery (Refinery) to receive up to 70,000 barrels per day (bbl/day) of North American crude oils by rail. The facilities that would be installed include about 8,880 feet of new track; a new tank car unloading rack capable of unloading two parallel rows of tank cars simultaneously; and 4,000 feet of 16-inch diameter crude oil pipeline and associated fugitive components (valves, flanges, pumps) connecting the offloading rack and an existing crude supply pipeline. DEIR, pp. ES-1 to ES-4.

Based on my review, I conclude this DEIR is fundamentally defective in that it omits crucial information to understanding the Project's significant impacts. Specifically, the DEIR does not disclose the Project's crude slate, relies on flawed analyses in addressing whether the Project would enable refining of substantial quantities of tar sands and Bakken crudes, relies on unsupported assumptions as to the Project's light crude composition, and underestimates the Project's operational emissions of reactive organic gases ("ROG") and toxic air contaminants ("TAC"). When these underestimates are corrected, the CBR Project results in significant air quality and public health impacts. The City must correct these defects and recirculate the DEIR, so that the public and decision-makers can be fully informed of the Project's air quality and public health and safety impacts.

My resume is included in Exhibit A to these Comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution control; greenhouse gas (GHG) emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; hazard investigations; risk of upset modeling; environmental permitting; nuisance investigations (odor, noise); environmental impact reports, including CEQA/NEPA documentation; risk assessments; and litigation support.

I have M.S. and Ph.D. degrees in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. 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.

---

[1] ESA, Valero Benicia Crude by Rail Project, Draft Environmental Impact Report, SCH # 2013052074, Use Permit Application 12PLN-00063, June 2014.

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. This work includes Environmental Impact Reports (EIRs), Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries; crude oil and rail terminals in California, Louisiana, Oregon, New York, Texas, and Washington; and various other permitting actions for tar sands and light shale crude refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas and liquefied natural gas (LNG) facilities in Texas, Louisiana, and New York.

My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (2001) 111 Cal.Rptr.2d 598 and *Communities for a Better Environment v. South Coast Air Quality Management Dist.* (2010) 48 Cal.4th 310.

I commented on the Initial Study/Mitigated Negative Declaration (IS/MND) (attached to the DEIR as Appx. A[2]) that the CBR Project would allow a change in crude oil slate quality, to heavier higher sulfur crudes and/or to lighter sweeter crudes, which would result in emission increases that were not considered in the CEQA review. Fox IS/MND Comments[3], pp. 2-35. The DEIR does not correct the defects that I identified in my IS/MND comments. Rather, it advances an argument that the rail-imported crudes will be blended with other crudes to meet the same sulfur and weight specifications as in the baseline Refinery. Thus, the DEIR asserts that crude slate quality and emissions from refining it would not change. This is incorrect. This does not address my comments on the IS/MND. Therefore, I reassert my IS/MND comments and incorporate them here by reference. The following sections present my evaluation of the DEIR's response to my previous crude slate switch comments, point by point. The DEIR's response to my comments is included in Appendices C.1 and C.2, based on a report contained in Appendix K. The following comments on Appendices C.1 and C.2 apply equally to the underlying analyses in Appendix K.

[2] ESA, Valero Crude by Rail Project, Initial Study/Mitigated Negative Declaration, Use Permit Application 12PLN-00063, Prepared for City of Benicia, May 2013.

[3] Phyllis Fox, Comments on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063, July 1, 2013; http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf.

I. THE DEIR FAILS TO ANALYZE THE AIR QUALITY IMPACTS FROM REFINING DIFFERENT TYPES OF CRUDE

A. Heavy Sour Crudes

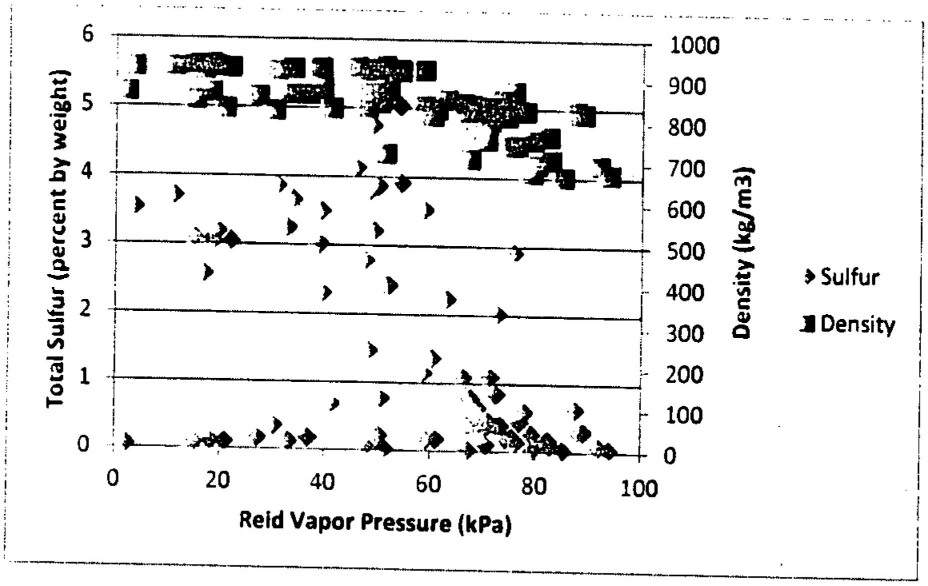
The CBR Project DEIR responds to the heavy sour crude slate issues that I raised in Appendix C.1. The thrust of the CBR Project DEIR's response is based on the "weight" (API gravity)[4] and sulfur content of the crude, which it argues would not change due to the Project, but rather would remain within a narrow range. Therefore, the CBR Project DEIR argues, emissions would not increase. The CBR Project DEIR argues: "Thus, to the extent that the Project would cause an increase in emissions based on an increase in the weight and sulfur content of crude feedstocks – any such emissions increase would be within the baseline environmental conditions." DEIR, Appx. C.1, p. C.1-3.

First, this misses the point, as explained in my previous comments at Section II.D, pp. 19-31. There are important differences between crudes that are not related to the weight and sulfur content of the crude that result in adverse impacts. Even if the weight and sulfur content of a particular crude blend fall within the range specified in the DEIR, or don't change at all, other components in the crude, such as TACs like benzene, or highly malodorous compounds such as mercaptans, may be present at much higher concentrations than in the crudes they replace with identical sulfur and API gravity.

Further, other characteristics of the crude, such as its vapor pressure or flammability, may differ in significant ways from the crudes they would replace. These other constituents and properties are not a function of the API gravity or the sulfur content and are present independent of them. The DEIR's consultant, Dr. McGovern, demonstrated there is no relationship between vapor pressure (expressed as RVP) and crude gravity (expressed as API). DEIR, Appx. K, p. K-18. This is further substantiated by analysis of data published by Enbridge, summarized here in Figure 1. The Enbridge data covering 76 different types of crude oil show that crude oil attributes of sulfur content and density are completely independent of vapor pressure.

[4] Note that throughout the DEIR, the term "weight" is used to indicate API gravity or density, where "density" is technically what is meant. We will use the same terminology in this report; "weight" indicates density.

Figure 1: Reid Vapor Pressure Compared to Total Sulfur and Density for 76 different types of Crude Oil



Source: Enbridge Pipelines Inc., 2013 Crude Characteristics, http://www.enbridge.com/~/media/www/Site%20Documents/Delivering%20Energy/2013%20Crude%20Characteristics.pdf

The vapor pressure of crude determines to a large extent the amount of ROG and TAC emissions that are emitted when it is transported, stored, and refined. Thus, a crude slate may have identical sulfur content and weight, but would result in dramatically different ROG and TAC emissions. Similarly, the nature of the chemical bonds in crude determines the amount of energy and hydrogen that must be supplied to refine it. Thus, a crude slate may have identical sulfur and weight, but a different mix of chemicals that would affect the amount of energy and hydrogen required to convert it into refined products.

These differences—in both chemical and physical characteristics other than API gravity and sulfur content— fluctuate independent of sulfur content and API gravity and will result in significant impacts that have not been considered in the DEIR. These impacts include, for example, significant increases in ROG emissions, contributing to existing violations of ozone ambient air quality standards; significant increases in TAC emissions, resulting in significant health impacts; significant increases in malodorous sulfur compounds, resulting in significant odor impacts; significant increases in combustion emissions, contributing to existing violations of ambient air quality standards; and significant increases in flammability and thus the potential for more dangerous accidents involving train derailments or spills on-site. The DEIR fails to consider these significant impacts by raising irrelevant issues.

Second, the rationale that sulfur levels and density of the crude slate would stay within a narrow range ignores the possibility of gradual creep within that range that would still be significant. This recently occurred at the nearby Chevron Richmond Refinery. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit.[5] This change increased corrosion rates in the 4-sidecut line, which led to a catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This accident sent 15,000 people from the surrounding area for medical treatment due to the release and resulting fire that created huge black clouds of pollution over the surrounding community. Fox IS/MND Comments, pp. 25–26.

These types of accidents can be reasonably expected to result from incorporating tar sands crudes into the Benicia crude slate, even if the range of sulfur and gravity of the crudes remain the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high total acid number (TAN) and high solids, which aggravate corrosion. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from tar sands crudes, leading to catastrophic releases.[6] Fox IS/MND Comments, pp. 35-36.

Catastrophic releases of air pollution from these types of accidents were not considered in the DEIR. Rather, the DEIR relies on the Refinery's existing Process Safety Management program, including the Management of Change (MOC) and Mechanical Integrity (MI) programs, to prevent corrosion. DEIR, p. 3-16. However, these programs were also in place at Chevron at the time of the August 2012 accident discussed above, and they did not prevent a catastrophic accident caused by sulfur creep. The recent Chevron FEIR incorporated many additional mitigation measures to improve these programs,[7] which should be required for the Valero Rail Project.

Third, the unloading rack, storage tanks and associated fugitive components are major sources of the ROG and TAC emissions. These unload, transport, and store crude oil as delivered, before it is blended. Therefore, the argument that the rail-imported crude is blended before it is refined is irrelevant.

[5] US Chemical Safety and Hazard Investigation Board, Chevron Richmond Refinery Pipe Rupture and Fire, August 6, 2012, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").

[6] See, for example, K. Turini, J. Turner, A. Chu, and S. Vaidyanathan, Processing Heavy Crudes in Existing Refineries. In: Proceedings of the AIChe Spring Meeting, Chicago, IL, American Institute of Chemical Engineers, New York, NY, Available at: http://www.aiche-fpd.org/listing/112.pdf.

[7] See, for example, Chevron Refinery Modernization Project, Revisions to Draft EIR Volumes 1& 2, p. 4-40, Mitigation Measure 4.13-7h, Available at: http://chevronmodernization.com/project-documents/.

1. The CBR Project DEIR Must Evaluate the Potential Impacts of the Full Range of Crude Oil Types That Could Be Imported

The CBR Project DEIR asserts: "There is no reason to believe that...Valero would be more likely to purchase heavy Canadian crudes than any number of other North American crudes that are lighter and/or sweeter..." DEIR, Appx. C.1, p. C.1-1. The CBR Project DEIR presents a table that lists 38 "available North American crudes" that could potentially be imported by the proposed rail facilities. DEIR, Table 3-1. Of these 38 crudes, 87% or 33 of them, are Canadian tar sands crudes and of the tar sands, 15 are "heavy sour" and 5 are "medium sour." Canadian tar sands crudes are chemically distinct from the current crude slate and thus will result in significant impacts that were not analyzed in the CBR Project DEIR. Fox IS/MND Comments, pp. 25-28. DEIR Table 3-1 is prima facie evidence that tar sands crudes are likely to be in the mix of crudes that will be imported by the CBR Project.

Regardless of which of these 38 crudes is selected, the DEIR must analyze the full range of resulting impacts, from all of the 38, as the DEIR suggests all or any of them may be refined. Impacts would vary greatly between tar sands crudes on the heavy high sulfur end and by Bakken crudes on the light sweet end, each end of this range with unique and significant impacts. The DEIR does not include impacts from either of these, but rather only an unidentified default crude that is not representative of any of the 38. See Comment III.

2. Blended Weight and Sulfur Content Do Not Determine ROG and TAC Emissions

The CBR Project DEIR argues that "even if Valero were to purchase large amounts of heavy sour Canadian crudes as a result of the Project, this would not cause an increase in refinery emissions because Valero must blend crude feedstocks to a narrow range of weight and sulfur content before processing them." DEIR, pp. 3-14, 3-24, 4.1-17, C.1-1/2. This is insufficient information to analyze impacts, as noted above, because the weight (API gravity) and sulfur content are not the only characteristics of crude oil that determine environmental impacts. Other important factors include volatility, flammability, metal content, ROG speciation profile, the specific suit of heavy organic compounds in the crude, and the TAC and sulfur speciation profile (i.e., the concentration of individual TAC and sulfur compounds present in the crude).

Elevated levels of benzene or hydrogen sulfide, for example, cannot be blended out because they are emitted from tanks and fugitive components before the crudes reach the mixing tanks. The majority of the toxic TACs and malodorous chemicals are emitted before blending occurs, during unloading and from fugitive components along the pipeline and at the storage tanks. Blending by itself does not eliminate them.

Similarly, elevated metals that end up in coke fugitive particulate emissions cannot be blended out. No matter how much blending is done with relatively less contaminated crudes, a significant amount of heavy metals from lower quality rail-imported crude would still remain, mostly partitioning to the coke. Blending also does not remove but only dilutes elevated concentrations of high molecular weight organic compounds such asphaltenes and resins that require high energy input to break down into marketable products. Fox IS/MND Comments, pp. 4-10. These characteristics may vary in significant ways among crudes with the same range of API gravity and sulfur, resulting in significant environmental impacts. Fox IS/MND Comments, pp. 29-30.

3. Crude Slate Impacts Are Not Part of the Baseline

The CBR Project DEIR indicates that Valero made significant modifications to the Refinery between 2004 and 2010. These modifications are collectively known as the "Valero Improvement Project" or VIP. The City certified the VIP project EIR and approved the VIP project in April 2003. It later certified the VIP EIR addendum in July 2008. DEIR, p. 3-12.

The CBR Project DEIR argues that crude slate impacts are part of the VIP baseline, "[e]ven if refinery emissions were to increase based on Valero's purchase of heavy sour Canadian crudes, any such emissions increases would properly be considered part of the baseline because the baseline includes the full scope of operation allowed under existing permits that were issued based upon prior CEQA review." DEIR, p. C.1-1. The DEIR cites several CEQA cases regarding subsequent environmental review for modifications to existing projects.

Setting aside legal considerations, this argument has no technical merits for three reasons. First, the scope of operations previously approved did not include any impacts from a crude slate change and did not contemplate the crudes listed in DEIR Table 3-1. Second, the CBR Project Project is not a modification of the previously permitted VIP, which underwent CEQA review. Third, even assuming the VIP EIR evaluated a crude slate change and the CBR Project is just a modification of the VIP, both of which are false, the regulatory framework has changed, requiring additional CEQA review.

a. The Scope of the VIP Project Did Not Include Impacts from Crude Slate Change

Even if the CBR Project were simply a modification of the VIP Project, the VIP EIR did not evaluate impacts from a crude slate change. The existence of permits, absent CEQA review of the proposed change, is not determinative.

The VIP CEQA documents do not discuss cost-advantaged North American crudes, such as those in CBR Project DEIR Table 3-1. None of these crudes is evaluated, or even identified, in the VIP EIR. Thus, the impacts of refining these crudes were in no way considered or incorporated. Therefore, the CBR Project DEIR cannot rely on the VIP CEQA review to address the impacts of refining any of them. Rather, the VIP EIR proposed to import heavy sour crudes by ship. The crudes available by ship in 2002 are chemically and physically different from the crudes available by rail in 2014, over a decade later. The oil markets have changed dramatically due to the advent of fracking and the development of tar sands, all of which occurred long after the VIP EIR analyses were performed.

There are many cost-advantaged, heavy high sulfur crudes that likely were the target of the VIP analyses prepared in 2002, such as heavy sour crudes from Ecuador, Venezuela, Colombia and Iraq, which were refined at the post-VIP Refinery. Fox IS/MND Comments, Figure 1. These heavy sour crudes are distinguishable from the crudes that are currently the target of the CBR Project, which are tar sands crudes and light sweet crudes with distinct physical and chemical characteristics. DEIR, p. C.2-1. The crudes that are currently the target of the CBR Project (DEIR, Table 3-1) were not available in the marketplace in 2002 when the VIP CEQA analysis was performed and thus were not considered in prior CEQA analyses. The differences between the crudes considered in the VIP EIR and those that would be imported by the CBR Project are discussed in my July 2013 comments on the IS/MND.

There is no evidence that the VIP was designed to refine, and that the VIP CEQA review addressed, the unique impacts of refining any of the cost-advantaged North American crudes listed in DEIR Table 3-1. Further, the lynchpin of the VIP EIR, a new, bigger hydrogen plant to allow refining of more heavy sour crude, may not be built as Valero has enough hydrogen to meet its current needs. DEIR, p. 3-12. This could be due to the availability of hydrogen from another source or a change in crude slate to lighter crudes that do not require more hydrogen to refine.

Bakken and Bakken blends with tar sands crudes, for example, would fall into this class. Further, the rail emissions assume a line haul one-way distance of 1,500 miles (DEIR, p. 4.1-22 and Appx. E.5, pdf 1197), which is consistent with Bakken crudes. There is no evidence in the record that impacts from refining this lighter, sweeter crude were considered in the VIP EIR. These impacts are discussed below in Comment I.B.

b. The CBR Project Is a New Project

The City did not treat the CBR Project as a modification of a previously permitted project in the IS/MND, but rather as a new project. Furthermore, even the DEIR refers to the VIP as a "previous" project. DEIR at 1-4. The characterization of the CBR Project as a modification of the VIP Project in the DEIR for baseline purposes improperly characterizes the projects and causes the CBR Project DEIR to underestimate or ignore real environmental impacts.

c. *The Regulatory Framework Has Changed, Requiring Additional CEQA Review*

Even if one hypothetically assumed that the VIP EIR evaluated the crude slate switch facilitated by the CBR Project, the regulatory and informational framework within which the CBR Project would be developed has changed dramatically, rendering the 2002 analysis obsolete. The City certified the VIP project EIR and approved the VIP project in April 2003. It later certified a VIP EIR addendum in July 2008. DEIR, p. 3-12. The Addendum incorporated a flue gas change related to the Main Stack Scrubber and added an analysis of greenhouse gas emissions. These changes do not affect any of the issues discussed here.[8]

When the VIP CEQA analysis was performed, none of the cost-advantaged crudes listed in Table 3-1 were in the marketplace. In response to ESA questions, for example, Valero responded that the CBR Project "was implemented to take advantage of land-locked North American crudes that have **recently** become available." Valero 2013,[9] p. 1 (emphasis added). As discussed earlier, these crudes are notably different from the current crude slate, in ways that are much broader than just sulfur content and weight. Thus, none of the impacts of refining these physically and chemically distinct crudes could have been anticipated and evaluated in 2002 when the VIP CEQA analysis was performed. Further, as explained in my comments on the IS/MND, the regulatory framework has significantly changed, requiring additional CEQA review even if the Project were a modification of a project that had previously undergone CEQA review. Fox IS/MND Comments, pp. 33-34.

Since the VIP FEIR was certified in 2003, new scientific evidence about the potential adverse impacts of air pollutants has become available, and in response, new guidance has been published and several federal and state ambient air quality standards have been revised. These include:

- The 8-hour state ozone standard was approved by the California Air Resources Board (CARB) on April 28, 2005 and became effective on May 17, 2006;
- The U.S. Environmental Protection Agency (EPA) lowered the 24-hour PM2.5 (particulate matter equal to or smaller than 2.5 micrometers) standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ in 2006. EPA designated the Bay Area as nonattainment of this PM2.5 standard on October 8, 2009;
- On June 2, 2010, the EPA established a new 1-hour SO_2 (sulfur dioxide) standard, effective August 23, 2010;

[8] Valero Improvement Project, Addendum to VIP EIR, June 2008, Available at: http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/%7B5A35F17D-5E23-404C-8032-6597BE84B5F9%7D.PDF.

[9] Valero Responses to: Valero Crude by Rail Project Data Request Number 2, April 2, 2013.

- The EPA promulgated a new 1-hour NO_2 (nitrogen dioxide) standard of 0.1 ppm, effective January 22, 2010;
- The EPA issued the greenhouse gas tailoring rule in May 2010, which requires controls of GHG emissions not contemplated in the VIP FEIR or the 2008 Addendum;
- The CARB has identified lead and vinyl chloride as "toxic air contaminants" with no threshold level of exposure below which there are no adverse health effects determined;
- The EPA issued a final rule for a national lead standard, rolling 3-month average, on October 15, 2008. The Project would increase lead emissions. Fox IS/MND Comments, p. 1, 20;
- Various BAAQMD regulations, including Regulation 2-2 (adopted December 19, 2012); and
- BAAQMD is currently developing a regional refinery regulation that could require additional emission controls.

B. Light Sweet Crudes

Light sweet crudes such as Bakken could be imported by rail and could result in an increase in ROG and TAC emissions from storage tanks, pumps, compressors, valves, and connectors that were not considered in the IS/MND. Fox IS/MND Comments, pp. 11, 25-28. The CBR Project DEIR concedes that "[o]nce the Project is constructed and operational, Valero may well purchase large amounts of light sweet North American crudes. In fact, this is Valero's stated plan." DEIR, p. C.2-1. Elsewhere, the DEIR notes that "[o]nce the Project is complete, Valero plans to obtain North American crudes that are, on average, lighter and sweeter than Valero's current feedstocks. According to Valero, the North American crudes will be 'Alaskan North Slope (ANS) look-alikes or sweeter' (Valero, 2013)." DEIR, p. 3-24. The closest and most cost advantaged of light sweet North American crudes listed in Table 3-1 that could be blended to be an ANS look-alike is Bakken crude.

An ANS look-alike crude, for example, could be created by blending 55% Bakken and 45% Western Canadian Select at a cost potentially far less than the ANS market price. The resulting mix has the same API gravity and slightly higher sulfur than ANS, and virtually identical distillation yields.[10] Both of these crudes are listed as available North American crudes in the DEIR. DEIR, Table 3-1. See also DEIR, pp. K-16/17. Alternatively, some of the lighter crudes, such as Bakken, could be fed directly to refining units, such as the fluid catalytic cracking unit (FCCU), eliminating the need for blending. Thus, the DEIR must evaluate the

[10] John R. Auers and John Mayes, North American Production Boom Pushes Crude Blending, Oil & Gas Journal, May 6, 2013, Available at: http://www.ogj.com/articles/print/volume-111/issue-5/processing/north-american-production-boom-pushes.html.

impacts of importing by rail and processing both Bakken and tar sands crudes, which span the range of likely impacts.

1. Bakken Crudes Have Properties That Will Result in Significant Impacts Not Evaluated in the DEIR

The DEIR makes the same arguments as to weight and sulfur content as previously made with respect to heavy sour crudes. The DEIR asserts that refining 70,000 bbl/day of light sweet crude would not cause an increase in ROG emissions because: "(a) Valero must blend crude feedstocks to a narrow range of weight and sulfur content before processing them, and (b) therefore, the average weight and sulfur content of crudes delivered to the Refinery will remain the same. In other words, any deliveries of light North American crudes by rail would simply replace the delivery of other light crudes by ship." DEIR, p. C.2-1. This is wrong for two principal reasons.

First, this is wrong because most of the ROG and TACs are emitted before the crudes are blended, from the rail cars, unloading, pipeline fugitive components (valves, pumps, connectors), and crude storage tanks. According to the Project description, two unit trains, each potentially carrying Bakken crude oil, would be unloading within a 24-hour period. DEIR, p. 3-22. This would result in an increase in daily ROG and TAC emissions, regardless of blending downstream to meet ANS-lookalike quality.

Second, this is wrong because all light sweet crudes are not created equal. The average weight (API gravity) and amount of sulfur in light sweet crudes do not determine the amount of ROG and TACs that will be emitted from Refinery tanks, pumps, compressors, valves, and connectors. The DEIR is correct when it asserts that "there is no relationship between the weight of a particular crude oil and the amount of fugitive emissions released from equipment containing that crude oil."" DEIR, p. C.2-1. See also Figure 1.

The amount of ROG and TAC emissions is determined by the "volatility" of the crude and the concentration of TACs within the crude, not by its weight or sulfur content. The volatility can vary widely for "light sweet crudes," independent of weight and sulfur content. Processing in the oil fields, in particular, significantly affects volatility of shipped crudes, as discussed below. Bakken crudes, which are likely to be imported by the CBR Project, have uniquely elevated volatility, which has led to many spectacular accidents, such as those that occurred at Lac-Mégantic[11]; Casselton, North Dakota[12]; Alabama[13]; and more recently, Lynchburg, Virginia.[14]

[11] NTSB, Safety Recommendation In reply refer to: R-14-4 through -6; January 21, 2014. Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

Volatility is measured in pounds per square inch (psi) and is typically reported as Reid Vapor Pressure (RVP).[15] Vapor pressure is an indirect measure of the evaporation rate of volatile compounds in the crude oil, with higher vapor pressures indicating greater losses from evaporation. The DEIR neglected to disclose the well-known relationship between the vapor pressure of a crude and the amount of emissions released from equipment containing the crude,[16] which is incorporated into the EPA TANK 4.0.9d model, universally used to estimate ROG and TAC emissions from tanks, including in the DEIR for this Project.

The CBR Project would facilitate the import of Bakken crudes, which have uniquely elevated vapor pressures compared to the light sweet crudes they would replace. As discussed elsewhere in these comments, most of the imported crude that would be replaced is Alaska North Slope (ANS) crude (API gravity = 31.6°, S = 0.96%) and similar or heavier foreign imports. The ANS crude has a Reid Vapor Pressure (RVP) of 6.3 psi.[17] Most foreign imports have an even lower RVP. In comparison, Bakken crudes (API gravity = 38-40°, S = 0.2%), the most likely replacement, have a RVP of up to 15.5 psi.[18] Thus, replacing ANS and foreign imports with Bakken would increase ROG and TAC emissions from tanks and fugitive sources by up to a factor of 2.5. The TAC emissions would increase even more as the concentration of TACs in the Table 3-1 crudes are much higher than in the current crude slate.

The volatility and TAC speciation information required to evaluate this crude switch, from ANS, to an ANS-look alike based on a Bakken blend, is completely absent from the DEIR. Vapor pressure and crude TAC speciation information are not confidential and are routinely

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12 NTSB, Preliminary Report; DCA14MR004, 2014. Available at: https://www.ntsb.gov/doclib/reports/2014/Casselton_ND_Preliminary.pdf.

13 Karlamangla, Soumya, "Train in Alabama oil spill was carrying 2.7 million gallons of crude." Los Angeles Times, http://articles.latimes.com/2013/nov/09/nation/la-na-nn-train-crash-alabama-oil-20131109, November 9, 2013.

14 Los Angeles Times, May 1 2014, http://www.latimes.com/nation/nationnow/la-na-nn-ntsb-investigation-fiery-crude-oil-train-derailment-virginia-20140501-story.html.

15 Measured by American Society for Testing and Materials Method ASTM D323-08, Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method) is used to determine the vapor pressure at 100 F with initial boiling point above 32 F.

16 See AP-42, Section 7.1: Organic Liquid Storage Tanks.

17 ExxonMobil Refining and Supply Company, ANS11U, Available at: http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx and http://www.exxonmobil.com/crudeoil/download/ans11u.pdf.

18 Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014, Available at: http://www.unece.org/fileadmin/DAM/trans/doc/2014/dgac10c3/UN-SCETDG-45-INF26e.pdf; Dangerous Goods Transport Consulting, Inc., A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation, Submitted by American Fuel & Petrochemical Manufacturers, May 14, 2014, pp. 5, 19, Available for download from: https://www.afpm.org;

North Dakota Petroleum Council, Bakken Crude Quality Assurance Study, Available at: http://www.ndoil.org/image/cache/Summary_2.pdf;

included in public documents to support tank and fugitive emission calculations. Further, crude assay data is widely reported.[19] See, for example, the Tesoro Vancouver Application.[20]

The DEIR offers irrelevant information to support its theory, arguing that "the amount of fugitive emissions from a piece of equipment is a function of the mechanical integrity of the equipment and the pressure applied to its contents. The weight of the crude oil is not a factor." DEIR, p. C.2-2. While this is partially correct, in that the design of the equipment and the pressure exerted by the contained crude oil on this design are important factors that determine the amount of emissions during routine operations, it fails to acknowledge other key factors such as RVP and TAC concentrations in the crude discussed above. The DEIR must evaluate the foreseeable scenarios of both light sweet crude, including Bakken, and heavy sour crude, including tar sands.

The foreseeable switch from ANS and other current components of Valero's crude slate to a Bakken crude or a Bakken-tar sands mix, included in DEIR Table 3-1, is a feedstock change that should have been explicitly identified and evaluated in the DEIR. These new crudes are chemically and physically different from the current crude slate and the crude slate evaluated in the VIP EIR in ways that are not captured by exclusive consideration of crude slate sulfur content and API gravity. These differences will result in significant impacts not evaluated or disclosed in the CBR Project DEIR.

Bakken crudes have unique chemical and physical characteristics that distinguish them from currently refined crudes and which would result in significant environmental impacts not identified in the DEIR, including significant risk of upset, air quality, odor, and public health impacts. These unique characteristics include high volatility, flammability,[21] and elevated concentrations of TACs and ROG.

The amount of TACs and ROG released from storage tanks and fugitive components depends upon the vapor pressure of the crude oil. Bakken crude oils are the most volatile of the

[19] Jeff Thompson, Public Crude Assay Websites, February 24, 2011. http://www.coqa-inc.org/docs/default-source/meeting-presentations/20110224_Thompson_Jeff.pdf.

[20] Tesoro Savage, Application for Site Certification Agreement (Vancouver Application), vol. 1, August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20I/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%20I.pdf and vol. 2, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

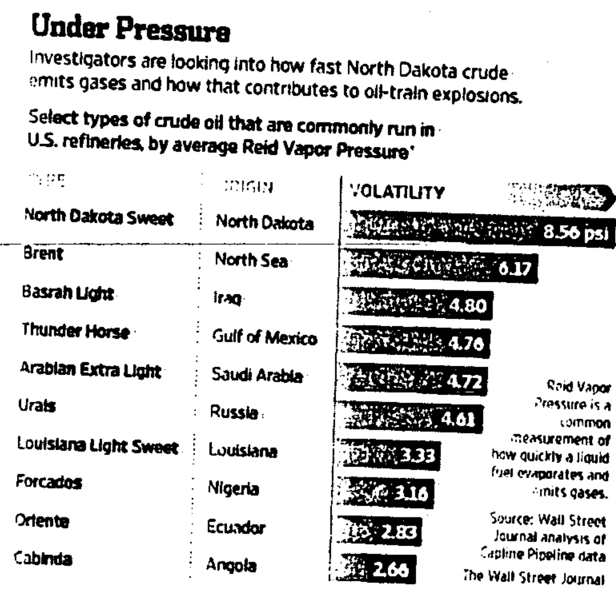
[21] Flammable crude oils will ignite when they are mixed with air in certain concentration ranges. The lowest temperature at which they produce sufficient vapor to support combustion is called the "flash point".

crudes listed in DEIR Table 3-1. Crude oil data collected by Capline Pipeline, which tested crudes from 86 locations world-wide for vapor pressure, found the following:[22]

> "[l]ight, sweet oil from the Bakken Shale had a far higher vapor pressure – making it much more likely to throw off combustible gases – than crude from dozens of other locations… According to the data, oil from North Dakota and the Eagle Ford Shale in Texas had vapor-pressure readings of over 8 pounds per square inch, although Bakken readings reached as high as 9.7 PSI. U.S. refiner Tesoro Corp., a major transporter of Bakken crude to the West Coast, said it regularly has received oil from North Dakota with even more volatile pressure readings – up to 12 PSI. By comparison, Louisiana Light Sweet from the Gulf of Mexico, had vapor pressure of 3.33 PSI, according to the Capline data."

This data, summarized in Figure 1, shows that "light" crude oils vary substantially in vapor pressure and thus would have a wide range of environmental impacts when stored and transported. The more volatile the crude, the higher the ROG, TACs, and methane (a potent greenhouse gas) emissions, the higher the flammability, and the greater the potential consequences in the event of an accident. Thus, the DEIR's assertions that there will be no increase in ROG and TACs as lights will replace lights is simply inaccurate.

Figure 2: Volatility (psi) of Some Commonly Refined Crude Oils

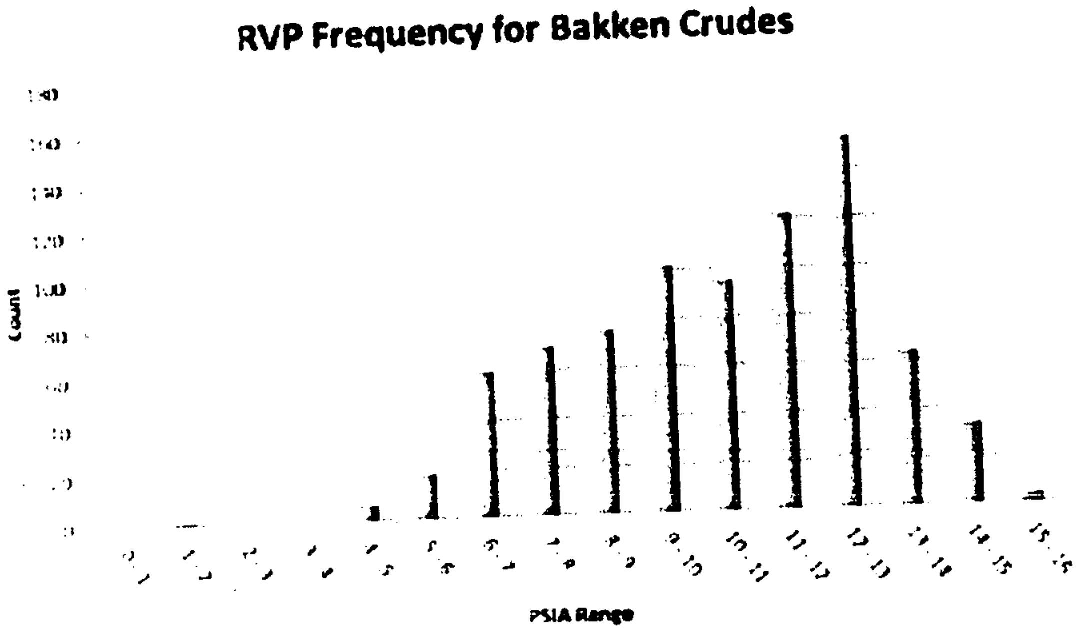


Source: Wall Street Journal, February 23, 2014

[22] Russell Gold, Analysis of Crude From North Dakota Raises Further Questions About Rail Transportation, Wall Street Journal, February 23, 2014.

Other data, summarized by American Fuel & Petrochemical Manufacturers[23] indicate that the RVP of Bakken crude oil can be substantially higher than the value reported based on Capline Pipeline data. A study of Bakken crudes involved in the Lac-Mégantic accident by the Transportation Safety Board of Canada (TSBC)[24] concluded that the volatility and flammability of Bakken crudes were more similar to gasoline than to crude oil, distinguishing Bakken crudes from conventional crude oils.

Figure 3



Source: Dangerous Goods Transport Consulting, Inc., 2014

Bakken and other light crude oils taken straight from the well typically contain large amounts of natural gas liquids (NGLs), known as light ends or condensate.[25] These include C2 to C5 hydrocarbons: methane, propane, butane, ethane, and pentane. These are the components most likely to volatilize, burn, or explode in an accident. These light ends have the effect of increasing a crude's vapor pressure, lowering its flash point and lowering its initial boiling point, all of which result in increased environmental risks. These are called "live" crude oils. The high concentration of light ends makes them highly flammable, more likely to form fire balls and

[23] Dangerous Goods Transport Consulting, Inc., 2014. North Dakota Petroleum Council.

[24] Transportation Safety Board of Canada, TSB Laboratory Report LP148/2013 (TSBC 2013). Available at: http://www.bst-tsb.gc.ca/eng/lab/rail/2013/lp1482013/LP1482013.asp.

[25] Dangerous Goods Transport Consulting, Inc., 2014. https://www.afpm.org/WorkArea/DownloadAsset.aspx?id=4229.

boiling liquid expanding vapor explosions (BLEVES) in accidents. The failure to recognize this resulted in a significant underestimate of ROG and TAC emissions and hazards in the CBR Project DEIR.

In most petroleum-producing regions, light ends are removed before they are shipped using a stabilizer—a tall, cylindrical tower that uses heat to separate the light ends, which are then condensed and sent to a fractionator for processing. Crude stabilizers and NGL pipelines to send the recovered NGLs to market are ubiquitous in oil fields that produce light crude oils as crude pipeline specifications set pressure limits that force stripping of the NGLs. However, in the Bakken fields, this infrastructure is rare and most Bakken crude that is shipped by rail is shipped live. This distinguishes it from other light crudes, which are shipped dry, e.g., Eagle Ford crudes in Texas, where oil field infrastructure exists to process it and most of it is shipped by pipeline, which requires that NGLs be stripped.[26]

Other crudes that Bakken would replace, such as ANS, are hard to ignite because they do not have as much combustible light ends. Most light crudes, including the imported foreign crudes currently processed, are stabilized. These stabilized crudes will not actively boil at ambient temperature and can be more safely shipped, stored, and refined. Thus, while "light" crude may replace other types of "light" crude, there are major differences in composition that affect environmental impacts. The CBR Project DEIR does not impose any condition(s) that require that NGLs be removed from received crudes to mitigate these impacts. Thus, analyses must assume that they will be present.

In addition, Bakken crudes, when blended with heavy crudes to meet crude slate requirements, have resulted in many refinery operating issues, which increase emissions. These include fouling of the cold preheat train; desalter upsets; and fouling of hot preheater exchangers and furnaces; as well as corrosion.[27] These operating problems increase emissions. These operating problems and attendant emission increases were not disclosed in the CBR Project DEIR.

2. Crude Slate Impacts Are Not Part of the Baseline

The DEIR next asserts that "[e]ven if VOC emissions were to increase based on Valero's purchase of light North American crudes, any such emissions increases would properly be considered part of the baseline because the baseline includes the full scope of operations allowed under existing permits that were issued based upon prior CEQA review." DEIR, p. C.2-1.

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[26] 'Degassing' North Dakota Crude Oil Before Shipping Among Safety Ideas, Insurance Journal, May 14, 2014. Available at: http://www.insurancejournal.com/news/national/2014/05/14/329095.htm.

[27] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html.

Elsewhere, the DEIR asserts, "Finally, even if one assumed that Valero will purchase 70,000 barrels per day of light sweet North American crude, and the crudes delivered and processed became substantially lighter, any resulting increase in emissions would be within the baseline for operational air quality impact." This is supported by citing the same suite of CEQA cases relied on for the parallel argument with respect to heavy sour crudes discussed above. DEIR, p. C.2-2. The response to this argument around heavy sour crudes applies equally here and is incorporated by reference.

The baseline argument for light sweet crudes goes a step further than for heavy sour crudes, arguing that "Valero holds permits for all of the Refinery's process equipment... The City and the BAAQMD issued these permits based on the environmental impact report (EIR) for the Valero Improvement Project (VIP) prepared and certified by the City in 2003. The baseline includes the full scope of operations allowed under these permits. In particular, the baseline includes the permitted operation of the Refinery's eight crude oil storage tanks (storage tanks S-57 through S-62, S-1047, and S-1048). In connection with the VIP, the BAAQMD issued permits based on the City's EIR." DEIR, p. C.2-3.

This mischaracterizes the VIP EIR and the permits for the subject tanks. The VIP EIR evaluated only the two new storage tanks (VIP DEIR, p. 3-51) and the increase in ROG emissions from several other unidentified tanks up to a 5 ton/year increase in ROG relative to a 3-year baseline, based on a vapor pressure of 5 psi.[28] VIP DEIR, Table 4.2-9. The CBR Project would facilitate an additional increase in ROG and TAC emissions from these tanks over the same 3-year baseline, due to an increase in the vapor pressure of the stored crude oils and higher amounts of TACs in the rail-imported crudes. Thus, the VIP EIR did not evaluate the full scope of the ROG and TAC emissions that would occur as a result of the CBR Project.

In addition, the VIP EIR analyzed the TAC emissions from these tanks. These emissions were based on a speciation profile that assumes far less toxic air contaminants than would be present in the crudes listed in the CBR Project. DEIR Table 3-1. For example, the VIP EIR calculations assumed that benzene would be present in the crudes stored in new Tanks 1707 and 1708 at 0.009 weight percent (wt.%).[29] The benzene content of the suite of tar sands crudes listed in DEIR Table 3-1 are substantially higher than 0.009 wt.%, ranging from 0.02 wt.% to

[28] The BAAQMD Permit Handbook in Chapter 3.1 refers to U.S. EPA's AP-42 guidelines, Chapter 5.2, in which a default RVP for crude oil is listed as 5 psi, though it is noted that RVP of crude oils can range from less than 1 up to 10 psi. See: http://hank.baaqmd.gov/pmt/handbook/rev02/PH_00_05_03_01.pdf and http://www.epa.gov/ttnchie1/ap42/.

[29] The benzene concentration assumed in the storage tanks is calculated from post-VIP ROG emissions of 193 ton/yr (VIP DEIR, Table 4.2-9) and the post-VIP benzene emissions of 33.93 lb/yr (VIP DEIR, Table 4.7-6) as: 100x[33.93 lb/yr/(193 ton/yr)(2000 lb/ton)] = 0.009 wt%.

0.81 wt.%,[30] or over 2 to 90 times higher. Similarly, Material Safety Data Sheets (MSDSs) submitted by others seeking to import similar cost-advantaged North American crudes, including Bakken, indicate benzene concentrations up to 7 wt.%,[31] with Bakken crudes generally having the highest concentrations of benzene among all those evaluated. Benzene is a known human carcinogen. Human exposure to benzene has been associated with a range of acute and long-term adverse health effects and diseases, including cancer and adverse hematological, reproductive and development effects.[32]

The CBR Project DEIR incorrectly asserts that "even if the Project were to cause an increase in ROG emissions from storage tanks, any such increase would be considered part of the baseline conditions." DEIR, p. C.2-3. The CEQA baseline is not determined by permit conditions, but rather by actual conditions. The full scope of tank operations, i.e., storing crude oils that have much higher vapor pressures and concentrations of TACs than existed in the market place at the time of the 2002 VIP CEQA review, were never subject to CEQA review and must be evaluated in the instant case.

II. THE DEIR UNDERESTIMATED ROG EMISSIONS

The DEIR estimated that the Project would result in a net decrease in ROG emissions of 1.61 ton/yr, as summarized in Table 1. DEIR, Table 4.1-5.

Table 1: Annual and Daily Net Operational ROG Emissions

Source	ROG* (ton/yr)	ROG** (lb/day)
Unloading Rack & Pipeline Fugitive Components	1.88	10.30
Locomotives	1.70	9.32
Marine Vessels (Displaced Baseline)	-5.18	-28.38
Total Net Emissions	**-1.61**	**-8.77**

* Source: DEIR Table 4.1-5

** Calculated as (ton/year)(2000 lbs/ton)/(365 days/year)

[30] www.crudemonitor.ca. Concentrations reported in volume % (v/v) in this source were converted to weight % by dividing by the ratio of compound density in kg/m^3 at 25 C (benzene =876.5 kg/m^3) to crude oil density in kg/m^3, based on the most recent sample, as of June 27, 2014.

[31] TSBC 2013: Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets for Enbridge Bakken (n-hexane = 11%); sour heavy crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%); sweet heavy crude oil (toluene = 7%); light sweet crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%). August 29, 2013. Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

[32] CARB. Report to the Scientific Review Panel on Benzene. Prepared by the Staffs of The Air Resources Board and The Department of Health Services, November 27, 1984, Available at: http://www.arb.ca.gov/toxics/id/summary/benzene.pdf; Chronic Toxicity Summary: Benzene, Available at: http://www.oehha.org/air/chronic_rels/pdf/71432.pdf; World Health Organization. Exposure to Benzene: A Major Public Health Concern. Available at: http://www.who.int/ipcs/features/benzene.pdf.

The DEIR underestimated ROG emissions as it excluded many sources of ROG emissions from the Project, discussed below. The *increase* in ROG emissions is significant when these omissions are cured.

A. Decrease In Ship Emissions Are Not Real Or Enforceable

The ROG emissions in Table 1 assume marine vessel emissions would be reduced by 5.18 ton/yr, by eliminating 73 vessel trips (70,000 bbl/day x 365 day/350,000 bbl/vessel). DEIR, p. 4.1-16. The DEIR asserts that "[c]rude oil delivered to the Refinery by tank car would not displace crude oil delivered to the Refinery by pipeline." DEIR, p. ES-3, 1-1.

However, it is well known that San Joaquin Valley crude oil production is declining.[33] The nearby Shell Oil Refinery in Martinez, for example, recently increased crude storage capacity to substitute imported crude oil by marine vessel "for diminishing San Joaquin Valley crude by pipeline." DEIR, Table 5-1. ESA expressed concern that ship deliveries could increase in the future to replace diminishing supplies of crude oil available by pipeline. Valero 2013, Data Request No. 2, Item 1.[34] Further, the BAAQMD Statement of Basis for the VIP Project states: "Valero anticipates the possibility that crude may no longer be brought in by pipeline. This could result from a problem with the pipeline, or a change in the cost of crude that makes pipeline supply no longer economical."[35] Thus, it is entirely possible, especially in the absence of any enforceable conditions of approval, that the Project would not decrease marine deliveries to the extent claimed in the DEIR.

The DEIR must be modified to include clearly stated and enforceable provisions to assure that any increase in ROG and TAC emissions from importing crude by rail rather than by marine vessel or pipeline are fully offset by reductions in ship emissions and that the reductions are achieved in practice. These conditions should include requirements to test, record, and report to the City the RVP of all crude oil delivered by ship, rail, and pipeline and source testing of representative ship and locomotive emissions to assure the reductions are achieved.

B. Storage Tanks ROG and TAC Emissions Were Omitted

The DEIR did not adequately quantify emissions from the tanks that would store the crude oil delivered by rail. The emissions from floating-roof tanks include: tank breathing losses

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[33] California Energy Commission, Margaret Sheridan, California Crude Oil Production and Imports, April 2006. Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF.

[34] Valero Responses to: Valero Crude by Rail Project Data Request Number 2, April 2, 2013.

[35] http://www.baaqmd.gov/~/media/Files/Engineering/Title%20V%20Permits/B2626/B2626_2010-05_renewal_03.ashx?la=en.

(the sum of rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses estimated by the EPA model TANKS 4.0.9d) and roof landing losses.

1. Significant Tank Breathing Losses Were Omitted

Tank breathing losses are estimated using the EPA model: TANKS 4.0.9d. The CBR Project DEIR did not include any emissions from the tanks that would store the rail-imported crude.

The CBR Project DEIR describes the Project as replacing 70,000 bbl/day of crude oil delivered by ship with 70,000 bbl/day of crude oil delivered by train. The CBR Project DEIR fails to consider what happens to the crude oil after it is transferred from the rail cars through a new pipeline. DEIR, Sec. 3.2. It simply states that the contents of each tank car will be pumped "into storage tankage located in the Refinery's crude oil storage tank field." DEIR, p. 3-20. This crude oil will be stored in existing storage tanks. As the imported crude oil will have a higher vapor pressure than current crude oils stored in these tanks, ROG and TAC emissions from the tanks will increase. The VIP EIR did not evaluate these emission increases. The CBR Project DEIR also does not include these ROG and TAC emissions.

The Project described in the IS/MND included transferring crude oil from rail cars into existing external floating roof tank 1776. This required changing the service of this tank from jet fuel and other refinery products to crude oil. The ROG emissions were estimated with the EPA TANKS 4.0.9d model for a throughput of 70,000 bbl/day and a crude oil RVP of 9.4 psi. The resulting ROG emissions were 39.3 lb/day and 7.18 ton/yr. The net ROG emission increase, relative to December 2009 through November 2012 baseline, was 23.7 lb/day and 4.33 ton/yr. DEIR, Appx. E.3 (2/13 Application, Table 3-2). The supporting calculations for these emission increases (in Appendix B to the February 2013 Application, provided in DEIR, Appx. E.3, Attachments B-1 and B-2) were withheld from the DEIR as confidential business information (CBI).

The Project was modified in November 2013 to replace Tank 1776 with Tanks 1701 through 1708 (S-57 through S-62). These are existing external floating roof tanks that are currently permitted to store crude oil and have historically stored crude oil delivered by both ship and pipeline. DEIR, Appx. E.4 (11/13 Application, p. 6). Thus, the baseline emissions from these tanks include both San Joaquin Valley crudes and ANS and other ship-imported crudes. These tanks are not in the Title V permit for the Valero Refinery, but rather in the Title V Permit for NuStar Logistics, L.P., Facility B5574. The November 2013 Application incorrectly asserts that these tanks are neither altered nor modified sources and thus are not subject to Authority to Construct and New Source Review requirements for the CBR Project. DEIR, Appx. E.4 (11/13 Application, p. 7). The November 2013 Application at p. 7 (DEIR, Appx. E.4) asserts:

"Changes in material stored. The tanks are currently permitted to store crude oil received by marine vessels and pipeline. With the implementation of this project, the tanks will continue to store crude oil. The crude oil will be received from rail cars, as well as from marine vessels and pipeline. Tanks 1701 through 1706 have historically stored crude oil delivered by ships and pipeline. Tanks 1707 and 1708 were recently constructed and were permitted under NSR to store crude oil. These tanks currently comply with all the requirements in Regulation 8, Rule 5, and associated permit conditions."

Similarly, the DEIR argues (DEIR, p. 4.1-17):

"Nor would the Project cause any emissions increases from storage tanks. Currently, the Refinery stores crude oil delivered by ship and pipeline in eight existing storage tanks numbered 1701 through 1708. Crude oil delivered by rail would be stored in the same tanks. The tanks would not be modified, and would continue to be subject to the same throughput limit and other permit conditions."

Thus, the DEIR does not include any ROG or TAC emissions from these tanks. However, this assertion is invalid, as explained above. The basis of this argument is that "Valero must blend crude feedstocks to a narrow range of weight and sulfur content before they can be processed into marketable products. Because the crude oil blends cannot become significantly heavier or lighter, nor contain significantly more sulfur, there would be no increase in processing emissions." DEIR, p. 4.1.17. This is immaterial as to ROG and TAC emissions because they do not depend on weight and sulfur content of the crude, but rather on vapor pressure and TAC speciation of the crude. These are not related to the gravity or sulfur content of the crude oil.

The ROG and TAC emissions from the receiving storage tanks would increase if 70,000 bbl/day of ship-imported or pipeline-imported crude were replaced with 70,000 bbl/day of rail-imported crude. The DEIR is deficient for failing to include any estimate of these emission increases and for withholding all information required to estimate these emissions, information that is never classified as CBI in public documents—vapor pressures, tank characteristics, baseline emissions, etc.

An approximate estimate of the increase in daily ROG emissions can be made from the previously reported daily ROG emissions for Tank 1776. The IS/MND estimated daily ROG emissions of 39.3 lb/day for a 70,000 bbl/day throughput of crude with an RVP of 9.4 psi. The RVP of the baseline crude in the seven storage tanks that would be used is unknown. However, the DEIR indicates that it is either San Joaquin Valley crude (pipeline) or Alaska North Slope lookalikes.

First, assuming the baseline crude has an RVP equal to that for Alaska North Slope crude, or 6.3 psi,[36] the baseline ROG emissions for 70,000 bbl/day would be **26.3 lb/day.**[37] The increase in ROG emissions, from storing 70,000 bbl/day of Bakken crude in the same tank(s), assuming the reported upper-bound vapor pressure for Bakken crude (15.5 psi)[38] would be **64.8 lb/day.**[39] Thus, the net increase in ROG emissions from replacing 70,000 bbl/day of ship-imported ANS with 70,000 bbl/day of rail-imported Bakken is **38.5 lb/day** (64.8 - 26.3 = 38.5). The corresponding net increase in annual emissions would be **7.0 ton/year**[40] if all of the rail-imported crude were Bakken. This is a reasonably foreseeable scenario as crudes required to blend 100% Bakken to an ANS-lookalike crude could be imported by marine vessel

Second, assuming the baseline crude has an RVP equal to that of San Joaquin Valley crude or other similar heavy sour crudes, 0.04 psi,[41] the baseline ROG emissions for 70,000 bbl/day would be **0.2 lb/day.**[42] As detailed above, the increase in ROG emissions, from storing 70,000 bbl/day of Bakken crude in the same tank(s), assuming the reported upper-bound vapor pressure for Bakken crude (15.5 psi)[43] would be **64.8 lb/day.**[44] Thus, the net increase in ROG emissions from replacing 70,000 bbl/day of pipeline-imported San Joaquin Valley or other similar heavy sour crudes with 70,000 bbl/day of rail-imported Bakken is **64.6 lb/day** (64.8 - 0.2 = 64.6). The corresponding net increase in annual emissions would be **11.8 ton/year** if all of the rail-imported crude were Bakken. This is a reasonably foreseeable scenario as crudes required to blend 100% Bakken to an ANS-lookalike crude could be imported by marine vessel.

The resulting daily net increase in ROG emissions for a San Joaquin Valley or other similar heavy crude baseline, but otherwise assuming all of the CBR Project DEIR's emissions, is 56 lb/day, as shown in Table 2. This increase in ROG emissions is significant, as it exceeds

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[36] ExxonMobil Refining and Supply Company, ANS11U, Available at: http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx and http://www.exxonmobil.com/crudeoil/download/ans11u.pdf.

[37] Baseline ROG emissions from storage of 70,000 bbl/day of ANS in one or more of existing tanks 1701 - 1708 = (39.3 lb/day) (6.3 psi/9.4 psi) = **26.3 lb/day.**

[38] Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014.

[39] Increase in POC emissions from storing 70,000 bbl/day of Bakken crude in one or more of existing tanks 1701-1708 = (39.3 lb/day)(15.5 psi/9.4 psi) = **64.8 lb/day.**

[40] Increase in annual emissions = (38.5 lb/day)(365 days/year)/(2000 lb/ton) = **7.02 ton/yr.**

[41] Emission Calculation Protocol for Oil Production Tanks, September 1, 2000.

[42] Baseline ROG emissions from storage of 70,000 bbl/day of ANS in one or more of existing tanks 1701 - 1708 = (39.3 lb/day) (0.04 psi/9.4 psi) = **0.17 lb/day.**

[43] Classification and Hazard Communication Provisions for Crude Oil – Bakken Crude Oil Data, June 13, 2014.

[44] Increase in ROG emissions from storing 70,000 bbl/day of Bakken crude in one or more of existing tanks 1701 - 1708 = (39.3 lb/day)(15.5 psi/9.4 psi) = **64.8 lb/day.**

the BAAQMD CEQA significance threshold[45] of 54 lb/day and triggers New Source Review thresholds that require Best Available Control Technology. This is a significant impact that was not disclosed in the DEIR. The total Project increase would be even greater than the emissions in Table 2, which do not include ROG increases from other omitted sources, discussed below.

Table 2: Revised Annual and Daily Net Operational ROG Emissions
San Joaquin Valley Crude Baseline

Source	**ROG** (ton/year)	**ROG** (lb/day)
Unloading Rack & Pipeline Fugitive Components	1.88	10.30
Locomotives	1.70	9.32
Storage Tank (SJV Crude Baseline)	***11.79***	***64.60***
Marine Vessels (Displaced Baseline)	-5.18	-28.38
Total Net Emissions	**10.19**	**55.83**
BAAQMD CEQA Significance Threshold	10	54
Significant?	**YES**	**YES**

The increase in ROG emissions in Table 2 would be accompanied by an increase in TAC emissions, which are estimated by multiplying the ROG emission increase by the weight percent of each TAC in the ROG emissions (i.e., the TAC speciation profile). The contribution of TAC emissions from these tanks were not included in the DEIR's health risk assessment, which only evaluated diesel particulate matter and PM2.5.

Because the Project would result in significant ROG emissions, the lead agency is required to examine the impact of the increase in localized ROG emissions on ambient air quality and the local community and identify mitigation that is capable of reducing or eliminating these impacts to below a level of significance. To mitigate the Project's significant ROG emissions, the City should consider feasible mitigation measures such as the use of zero-leak fugitive components; use of geodesic domes on external floating roof tanks, which are commonly used on tanks that store RVP 11 crude oils; cable-suspended, full-contact floating roofs; and the use geodesic domes on the existing fixed roof tanks.[46]

[45] BAAQMD Proposed Air Quality CEQA Thresholds of Significance, May 3, 2010, Available at: http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Summary_Table_Proposed_BAAQMD_CEQA_Thresholds_May_3_2010.ashx?la=en.

[46] See, e.g., Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, September 6, 2013, Draft Negative Declaration (Carson Neg. Dec.), Available at: https://www.aqmd.gov/CEQA/documents/2013/nonaqmd/Draft_ND_Phillips_66_Crude_Storage.pdf and City of Richmond, Chevron Refinery Modernization Project DEIR (Chevron DEIR), Chapter 4.3, pp. 4.3-92, Available at: http://chevronmodernization.com/wp-content/uploads/2014/03/4.3_Air-Quality.pdf.

2. <u>Roof Landing, Degassing, and Cleaning Emissions Were Omitted</u>

The increase in ROG emissions estimated above is based on an adjustment of a calculation in the IS/MND based on EPA's TANKS 4.0.9d model (TANKS). However, this model only estimates rim seal losses, withdrawal losses, deck fitting losses, and deck seam losses. It does not estimate roof landing losses, inspection losses, or flashing losses. Thus, it underestimated tank emissions. Therefore, the above estimate of the increase in ROG emissions in Table 2 is an underestimate. These additional emissions should be estimated, added to other tank emissions, and mitigated when the DEIR is revised.

The Project involves seven existing external floating roof tanks configured to comply with BAAQMD Regulation 8-5. DEIR, p. 3-5. These tanks are pontoon-type tanks. DEIR, Appx. E.4 (2/13 Application, p. 1-8). Pontoon tank roofs are supported on legs. In floating roof tanks with leg-supported roofs, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operations. However, when the tank is emptied, the roof sits on the legs and is essentially uncontrolled.

The EPA has explained that the TANKS model does not include roof landings, and recommended that they be estimated with the equations in AP-42. In other words, the EPA TANKS model estimates evaporative emissions for normal operations only, *i.e.*, it assumes that the floating tank roof is always floating.[47] However, when a tank is emptied to the point that the roof no longer floats on the liquid but lands on deck legs, evaporative losses occur.

> After the floating roof is landed and the liquid level in the tank continues to drop, a vacuum is created which could cause the floating roof to collapse. To prevent damage and to equalize the pressure, a breather vent is actuated. Then, a vapor space is formed between the floating roof and the liquid. The breather vent remains open until the roof is again floated, so whenever the roof is landed, vapor can be lost through this vent.[48]

These losses are called "roof landing losses."

In addition, "degassing and cleaning losses" occur when tanks are drained and degassed for inspection and/or cleaning. These include both roof landing emissions, complete tank

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

[48] EPA, AP-42, Chapter 7.1 Organic Liquid Storage Tanks, November 2006, Available at: http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

degassing, and emissions from cleaning out accumulated sludge. These emissions are essentially uncontrolled tank emissions.[49]

The tank cleaning emissions could be substantially higher for Bakken crudes than for other types of crude. Bakken crudes leave waxy deposits in pipelines and tanks, which require more frequent cleaning,[50] and thus higher emissions, than the crudes they would replace. Environmental impacts from chemical dispersants used to control these waxy deposits in tanks and pipelines also should be evaluated.

The EPA recommends methods to estimate emissions from degassing and cleaning and roof landing losses.[51] The method for estimating emissions depends on the construction of the tank, *e.g.*, the flatness of the tank bottom and the position of the withdrawal line (the so-called liquid "heel"). Degassing, cleaning, and roof landing losses continue until the tank is refilled to a sufficient level to again float the tank roof. Total ROG emissions from floating roof tanks during a roof landing is the sum of standing idle losses and filling losses. They can be estimated using formulas contained in EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 7.1, Organic Liquid Storage Tanks, Section 7.1.3.2.2. These emissions are routinely included in emission inventories. They are required to be reported, for example, in Texas.[52] They are also included in the emission inventory for Tesoro's Vancouver Terminal, which imports similar crudes by rail, and stores them in tanks.[53]

To reduce emissions from tank breathing losses (Comment II.B.1), degassing, cleaning and roof landing losses, the City should require the Applicant to install geodesic domes on the tanks that would store rail-imported crudes, thus avoiding emissions from these and other tank sources.

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

[50] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, Available at: http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html.

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

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

[53] Tesoro Savage, Application for Site Certification Agreement, Section 5.1.2.1.4, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%201/EFSEC%202013-01%20-%20Compiled%20PDF%20Volume%201.pdf .

Over 10,000 aluminum domes have been installed on petrochemical storage tanks in the United States.[54] The ExxonMobil Torrance Refinery: "completed the process of covering all floating roof tanks with geodesic domes to reduce volatile organic compound (VOCs) emissions from facility storage tanks in 2008. By installing domes on our storage tanks, we've reduced our VOC emissions from these tanks by 80 percent. These domes, installed on tanks that are used to store gasoline and other similar petroleum-derived materials, help reduce VOC emissions by blocking much of the wind that constantly flows across the tank roofs, thus decreasing evaporation from these tanks."[55]

A crude storage project, recently proposed at the Phillips 66 Los Angeles Carson Refinery, required external floating roof tanks with geodesic domes to store crude oil with an RVP of 11.[56] Carson Neg. Dec. Table 1-1. The ConocoPhillips Wilmington Refinery added a geodesic dome to an existing oil storage tank to satisfy BACT.[57] Similarly, Chevron proposes[58] to use domes on several existing tanks to mitigate VOC emission increases at its Richmond Refinery.[59] The U.S. Department of Justice CITGO Consent Decree required a geodesic dome on a gasoline storage tank at the Lamont, Texas refinery.[60] Further, numerous vendors have provided geodesic domes for refinery tanks.[61] The crudes that would be stored in the Project tanks have vapor pressures that are comparable to gasoline (TSBC 2013, Sec. 3.2.7), justifying the use of geodesic domes to control tank emissions.

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

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

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

[57] SCAQMD Letter to G. Rios, December 4, 2009, Available at: http://yosemite.epa.gov/r9/air/epss.nsf/e0c49a10c792e06f8825657e007654a3/e97e6a905737e9bd882576ed0064b56a/$FILE/ATTTOA6X.pdf/ID%20800363%20ConocoPhillips%20Wilmington%20-%20EPA%20Cover%20Letter%20%20-AN%20501727%20501735%20457557.pdf.

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

[59] Chevron DEIR, Chapter 4.3.

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

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

3. Tank Flashing Emissions Were Omitted

Most Bakken crudes are transported raw, without stabilization, due to the lack of facilities in the oil fields, as discussed elsewhere in these Comments. Unstabilized or "live" crude oils have high concentrations of volatile materials entrained in the bulk crude oil. Tank flashing emissions occur when these crude oils, such as Bakken, are exposed to temperature increases or pressure drops. When this occurs, some of the compounds that are liquids at the initial pressure/temperature transform into gases and are released or "flashed" from the liquid. These emissions are in addition to working and breathing emissions from tanks and are not estimated by the EPA TANKS 4.0.9d model. These emissions can be calculated using standard procedures.[62] The DEIR did not mention or calculate these emissions, nor does it include permit conditions that would allow only stabilized crude oils to be received.

4. Water Draw Tank Emissions Were Omitted

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

C. Rail Car Unloading Emissions Were Omitted

The Project includes a rail car unloading rack capable of unloading two parallel rows of 25 crude oil rail cars simultaneously. DEIR, p. ES-3. The DEIR does not disclose any emissions from the unloading process, while EIRs for other similar facilities such as the proposed Phillips 66 CBR Project in Santa Maria, report unloading emissions.[63]

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

[63] Marine Research Specialists (MRS), Phillips 66 Company Rail Spur Extension Project Public Draft Environmental Impact Report and Vertical Coastal Access Assessment, November 2013; p. 2-14, Available at: http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/Draft+EIR-Phillips+66+Rail+Spur+Extension+Project+(November+2013)/Full+EIR+-+Large+File/p66.pdf.

At Valero, each side of the rack would have 25 unloading stations, which would "bottom-unload" closed-dome tank cars using 4-inch-diameter hoses, with dry disconnect couplings that would connect to a common header between the two sides of the rack (a check valve, connected to the top of each tank car via 2-inch-diameter hose would open to allow ambient air to enter during unloading and immediately close when unloading is finished). DEIR, p. 3-2.

A check valve would be installed onto each vent valve on the top of each tank car. The vent valve on the top of each tank car would be opened and the accompanying check valve would only allow fresh air into each tank car, and would prevent release of hydrocarbon fugitive emissions to the atmosphere. At each end car and on approximately every 8 tank cars in the 25 tank car string, a hose would be connected from the tank car's vent connection to a separate "equalization header." The equalization header would ensure the vapor spaces above the stored liquid crude in the tank cars is equalized between the tank cars. Individual drain hoses would be manually connected to the bottom of each tank car by on-site workers. The contents of each tank car would be drained by gravity into a collection pipe (collection header) and then pumped directly into storage tanks. DEIR, p. 3-21.

A typical rail car unloading system is described differently in the Santa Maria Rail DEIR. Santa Maria DEIR, p. 2-14. In that DEIR, the rail car unloading system consists of an adapter unit that connects the rail car to couplings, hoses, valves and piping that connect to a positive displacement pump. Air and crude oil vapors are commonly mixed in with crude oil, from loading and evaporation during transit. These vapors can present an explosion risk for downstream equipment and are typically removed with air eliminators. As the vapors contain high concentrations of ROG and TACs, they are typically routed to carbon columns or an incinerator to control the emissions.

The Valero CBR Project DEIR does not mention these vapors, an air eliminator, or indicate how they will be controlled. The Valero CBR Project DEIR only notes that "the BAAQMD will consider locomotive emissions and tank car unloading emissions as may be caused by the Project." DEIR, p. 3-2. This is not adequate. If unloading emissions will occur, at an air eliminator or other release point, the DEIR should be modified to describe them and to quantify them. If they are not present, the DEIR should explain how the explosion hazard typically associated with unloading cargos such as Bakken crude will be addressed as it is not clear that the air equalization system would eliminate this hazard.

D. Sump Emissions Were Omitted

The unloading facility includes a liquid spill containment sump with the capacity to contain the contents of at least one tank car. DEIR, p. ES-2. Crude oil that spills into this sump would release vapors including ROG and TAC emissions. The DEIR did not include these emissions.

E. Rail Car Fugitive Emissions Were Omitted

ROG and TACs will be emitted from rail cars from their point of origin through unloading as rail cars are not vapor tight. The DEIR did not include these emissions.

The crude oil would be shipped in tank cars, such that the volume of loaded crude oil shipped is less than the capacity of the rail car to accommodate expansion during shipping. This volume reduction creates free space at the top of the tank car, which provides space for entrained gases to be released from the crude oil[64] and emitted to the atmosphere during transit and idling in rail yards.[65]

As rail cars are not vapor tight, these vapors in the head space above the oil are emitted to the atmosphere during rail transport and at the unloading terminal. Further, most Bakken crudes are shipped live as discussed earlier. These crudes will flash in the tank cars when exposed to temperature increases or pressure drops, causing valves to open, emitting ROG and TACs.

These losses are consistent with the well-known "crude shrinkage" issue associated with crude by rail. The crude delivered is significantly less than the crude loaded. The reported range in crude shrinkage is 0.5% to 3% of the loaded crude.[66] Some of this shrinkage is likely due to emissions from the rail car during transit. The emissions of ROG and TACs from rail cars has been confirmed by field measurements.[67] The DEIR did not include these ROG and TAC emissions in its emission calculations or the health risk assessment.

Tank cars have domes to allow space for the product to expand as temperatures rise. Each dome has a manhole through which the tank car can be loaded, unloaded, inspected, cleaned, and repaired. Dome covers may be hinged and bolted on or screwed on. Most domes

[64] Anthony Andrews, Congressional Research Service, Crude Oil Properties Relevant to Rail Transport Safety: In Brief, February 18, 2014, pp. 8-9.

[65] A DOT 111 (or comparable) tank car generally has a capacity of 34,500 gallons or 263,000 lbs. gross weight on rail. Under some conditions, the maximum gross weight can be increased to 286,000 lbs. At an API gravity of 50°, a tank car can hold its maximum volume of 31,800 gallons and not exceed the 286,000 lb gross weight on rail limit. As the API gravity drops, the amount of oil that can be carried must also drop. Thus, a tank car of Bakken crude, at its highest density of 39.7° API, can only hold 30,488 gallons, a volume reduction of about 1,300 gallons. Further, as crude oil density (and thus API gravity) is temperature dependent, volume will increase as temperature increases. Thus, the shipper may have to reduce the shipped volume even further. This volume reduction creates a space above the crude oil where vapors accumulate.

[66] Alan Mazaud, Exergy Resources, Pennsylvania Rail Freight Seminar, May 23, 2013, p. 17. Available at: http://www.parailseminar.com/site/Portals/3/docs/Alan%20Mazaud%20Presentation%20-%20AM.pptx

[67] http://www.youtube.com/watch?v=35uC1gLctnw.

have vents and safety valves to let out vapors.[68] Thus, they are sources of ROG emissions that were omitted from the emission calculations. Further, when dome covers are left open, any residual vapors escape to atmosphere. Residual material clings to the bottom and sides of empty rail cars and emits ROG and TAC while the rail cars idle at the site, waiting for the entire unit train to be unloaded. Open covers are common in railyards as they are opened for inspections and repairs. The ROG and TAC emissions from these sources were omitted from the DEIR's emission inventory.

Further, each tank car has a bottom outlet which is used for loading and unloading that includes pumps, manifolds, and valves, all of which leak ROG and TACs. Finally, liquid leaks occur when unloading arms are disconnected, even for the so-called no leak arms proposed for the Project. These disconnect leaks evaporate, contributing to ROG and TAC emissions.

An estimate of these emissions can be based conservatively on the lower end of the range of crude shrinkage (0.5%) discussed above and the maximum freight weight per car of 106 tons from the TRN Spec Sheet-1. DEIR, Appx. E.6 (6/11/14 Memo to Morgan from Velzy, pdf 1208). Assuming 50 cars/train and two unit trains per day, a total of 53 ton/day[69] of ROG can be emitted as the trains traverse the 1500 miles between the shipping point and the Valero rail terminal. Of these 1500 miles, 263 miles are within California.[70] DEIR, Appx. E.5 (Air Quality & GHG Supplement, pdf 1198). Thus, 9.3 ton/day of ROG (18,600 lb/day) can be emitted within California from rail car leakage.[71] Of the 263 miles within California, 22 miles are within the boundary of the BAAQMD. *Ibid.* Thus, 0.8 ton/day (1,555 lb/day) of ROG emissions can be emitted within the BAAQMD.[72] These daily emissions greatly exceed the BAAQMD daily CEQA significance threshold for ROG of 54 lb/day, requiring mitigation.

Additional ROG would be emitted at the Valero railyard, while railcars wait for the entire train to be unloaded, and from the emptied railcars, enroute to the cleaning facility, from residual product that clings to the bottom and sides of the railcars.

These ROG emissions contain the same chemicals found in the crude oil, including benzene, toluene, xylene, hexane, and ethylbenzene. As discussed below, some crudes can contain up to 7% benzene by weight. See Table 3 below. Thus, greater than 1,301 lb/day of benzene could be emitted in California and greater than 109 lb/day of benzene within the

[68] Chapter 11. Tank Car Operations, Available at: http://www.globalsecurity.org/military/library/policy/army/fm/10-67-1/CHAP11.HTML.

[69] ROG emissions from train transit = (106 ton/car)(50 car/train)(2 train/day)(0.005) = **53 ton/day.**

[70] Distance within California = (136+390)/2 = 263 mi.

[71] ROG emitted within California = (318 ton/day)(263/1500) = **9.3 ton/day.**

[72] ROG emitted within BAAQMD = (318 ton/day)(22/1500) = **0.8 ton/day.**

BAAQMD from rail car leakage. This rail car leakage is much greater than the amount of benzene (and other TACs) included in the HRA. For example, the HRA included only 0.06 lb/day of benzene[73] from fugitive components (DEIR, Appx. E.4, pdf 1160) or a tiny fraction of the 109 lb/day of benzene that could be emitted within the BAAQMD from the rail cars themselves.

These are huge emissions, greatly exceeding the ROG (and HRA) CEQA significance thresholds of the BAAQMD and other air district along the rail route. See DEIR, Tables 4.1-5 and 4.1-6. The City must require mitigation for these ROG and TAC emissions.

III. THE DEIR FAILS TO DISCLOSE AND UNDERESTIMATES TAC EMISSIONS USED IN HEALTH RISK ASSESSMENT

Health Risk Assessments (HRAs) typically contain tables that summarize the amount of each TAC and the corresponding cancer, chronic, and acute health risk due to each. The supporting TAC emission calculations are presented in an appendix. The modelling files are separately attached. The HRA in this DEIR does not include most of this information. (Modelling files are available on a CD, which must be requested.) The supporting emission calculations are incomplete and scattered throughout many appendices with no road map explaining how it all fits together, with many analyses superseded.

There is no evident basis for concluding the Project would not result in a significant health impacts as the results are simply stated without the supporting emission calculations, leaving the reader the chore of digging through thousands of pages of appendices to make guesses at the TAC emissions included in the HRA analysis.

My analysis of this material indicates that the HRA only included diesel particulate matter and PM2.5 emissions from locomotives and TAC emissions from fugitive sources, a comparatively minor source of TAC emissions. The TAC emissions from all other sources (storage tanks, idling rail cars) discussed in Comment II were excluded. The TAC emissions from fugitive sources were underestimated, as explained below.

The unloaded crude oil will be transported from the unloading rack to existing crude supply piping in a 4,000–foot-long pipeline. DEIR, p. 1-2. The connecting system includes 3 pumps, 521 valves, 940 flanges, 295 connectors, and 6 pressure relief valves (plus a 15% contingency for valves, flanges and connectors). DEIR, Appx. E.4-1 (11/13 Application, pdf 1179). Crude oil vapors will be emitted from all of these components. The DEIR estimated TAC emissions from these components by first estimating ROG emissions using CARB

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[73] Benzene in fugitive emissions from Ex. E.4, Table 3-5: (2.57E-3 lb/hr)(24 hr/day)/(2000 lb/ton) = **3.1E-5 ton/day.**

emissions factors. The ROG emissions were then multiplied by the weight percent of each TAC in the crude.

The TAC emissions from fugitive components were estimated using the "default speciation profile" for crude oil from the EPA program, TANKS4.09.[74] DEIR, Appx. E.4-1 (11/13 Application, pdf 1179, footnote). A "speciation profile" for a petroleum product identifies each chemical in the liquid and its concentration, reported as volume or weight percent. The default speciation profile used in the DEIR is not representative of the crude oil(s) that could be imported at the rail terminal and is entirely hypothetical. DEIR, Table 3-1. The conclusion that the hypothetical speciation profile is appropriate to evaluate Project health impacts is unsupported.

My review of the HRA speciation profile indicates that it is not based on the maximum amount of each TAC found in the crude oils that could be stored in the tanks. Material Safety Data Sheets (MSDSs) submitted in other applications to import cost-advantaged North American crudes[75] indicate that much higher concentrations of TACs could be present in the crude oils unloaded at the Valero Rail Terminal.

The upper bound values from these MSDSs are summarized in Table 3 and compared with the speciation profile used in the DEIR. This table shows that the HRA significantly underestimated all of the organic TACs included in the HRA. Similar information for diesel particulate matter, the only other TAC included in the HRA, is not available in the documents I reviewed.

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[74] Crude oil component speciation data was obtained by using the TANKS409d model available at http://www.epa.gov/ttnchie1/software/tanks/ using the database interface to export the speciation profile for the TANKS default crude oil, *viz.*, "Data --> Speciation Profiles --> Export" menu selection and choosing crude oil. This spreadsheet confirms that the default benzene level for crude oils is 0.6 wt.%.

[75] Tesoro Application to SCAQMD for Tank 80079 Throughput Increase, October 3, 2013, PRN 556835 (10/3/13 Application), MSDS for Light Sweet Crude, pdf 12; Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets, August 29, 2013, Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf.

Table 3: Comparison of DEIR Draft EIR, Appx. E.4, Table 3-5, HRA Speciation Profile for Fugitive Emissions with Maxima Reported in MSDS(s)[76]

TAC	HRA Speciation Profile[77]	Weight Percent Maxima MSDS	Factor Difference
Benzene	0.6	7	11.7
Ethyl Benzene	0.4	7	17.5
Hexane	0.4	11	27.5
Toluene	1	7	7.0
Xylenes	1.4	7	5.0

Table 3 shows that the risk assessment underestimated the amount of benzene, ethyl benzene, hexane, toluene and xylenes in emissions by factors of 5 (xylenes) to 28 (hexane). Actual TAC emissions, after adjusting for the speciation profile, would be much higher as the DEIR excluded most of the sources of ROG emissions that would contribute TACs. The increase in benzene alone is large enough to increase the cancer risk at the maximum exposed individual worker (MEIW) over the BAAQMD Regulation 2-5 significance threshold of 1 in one million. DEIR, Appx. E.4-1 (11/13 Application, pdf 1189).

The DEIR argues that the benzene content of two Canadian crudes are on average lower than the benzene content of Alaska North Slope crude (0.33%), the design crude for the refinery. DEIR, Appx. K, p. K-17. However, the benzene content of other crudes listed in DEIR Table 3-1 are on average much higher than ANS. Light crudes, like Bakken, have been reported to contain benzene concentrations of up to 7 weight %, or twenty-one times more than the design ANS crude.

In sum, the DEIR fails to properly analyze the health impacts of importing, storing, and refining the crude oil that the CBR Project will likely bring to Valero.

[76] Tesoro Savage, Application for Site Certification Agreement, vol. 2, Appendix G: Material Safety Data Sheets for Enbridge Bakken (n-hexane = 11%); sour heavy crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%); sweet heavy crude oil (toluene = 7%); light sweet crude oil (benzene = 7%; toluene = 7%; ethylbenzene = 7%; xylene = 7%), August 29, 2013. Available at: http://www.efsec.wa.gov/Tesoro%20Savage/Application/EFSEC%202013-01%20Volume%20II%20-%20Appendices/EFSEC%202013-01%20Compiled%20Volume%20II.pdf. See also 3/7/13 Revised Application, pdf 96-115.

[77] DEIR, Appx. E.4, Table 3-5, pdf 1160.

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

PSX - Q3 2013 Phillips 66 Earnings Conference Call

EVENT DATE/TIME: OCTOBER 30, 2013 / 03:00PM GMT

THOMSON REUTERS

Doug Terreson, ISI group.

Doug Terreson - ***ISI Group - Analyst***

Good morning everybody. I have a couple of questions on refining. First, the Company has significantly increased use advantaged crudes in the past couple of years with significant benefits. While it may be hard to know, I wanted to see whether Greg can talk a little bit about how much running room that the Company may have in this area in coming years. Second, the unfavorable delta for secondary products seemed to increase in each of the major regions, especially on the Gulf Coast and Central Corridor. I think Greg attributed this to rising feed stock costs. I just wanted to see if there was any additional color on that decline, and also whether or not there was anything specific to those regions that caused them to be affected more than the others?

Greg Garland - ***Phillips 66 - Chairman and CEO***

I'll take a stab, and then Tim and Greg can kind of help answer the question. If you think about the running room, you know, we plan, Doug, to eventually get to 100% advantaged crude across the refineries. That's some combination of getting more crude East and West because that's where we still have the opportunities. When you think about Bayway and you think about the West Coast refineries, rail is a key piece of that. We're adding capabilities. We're taking more cars. By the end of this year, we think we'll have all the 2,000 cars in place that we've purchased. We're thinking about buying some more rail cars. We certainly have a large project underway at Bayway to be able to unload at Bayway 75 a day. We're trying to get Bayway positioned where we can get it on a pretty steady diet of Bakken. We have the Jones Act vessels where we can run Eagle Ford around to Bayway. We're working that. We've said this for a while that we do think that crudes like LLS become an advantaged crude for us on the Gulf Coast. While today we would lump that in the 500,000 barrels a day of Brent based crude that we're running, ultimately it becomes an advantaged crude. I do think between what ourselves and others are doing on the West Coast, we're going to pressure ANS prices, and so ANS, rather than being a Brent base type crude, it becomes an advantaged crude. They're partly the actions we're taking, and the actions others are taking, that put pressure on some of these crudes. I think we do get to 100% advantaged crude over the next couple of years.

Clayton Reasor - ***Phillips 66 - SVP, IR, Strategy, and Corporate Affairs***

Secondary product.

Greg Maxwell - ***Phillips 66 - CFO***

Secondary products. Crude prices went up 8% to 12%. TI was up 12%. Brent's up 8% this quarter, over the last quarter. Our prices stayed flat for a lot of the secondary products. That's where we saw the compression.

Tim Taylor - ***Phillips 66 - EVP***

Primarily coke and NGL prices did not keep up pace with the crude price.

Doug Terreson - ***ISI Group - Analyst***

Okay. Thanks a lot guys.

Operator

Evan Calio, Morgan Stanley.

Evan Calio - ***Morgan Stanley - Analyst***

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COMMUNITIES FOR A BETTER ENVIRONMENT

January 28, 2015

Saundra McDaniel
Clerk of the Boards
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

[Via US Mail]

Re: NOTICE OF INTENT TO FILE CEQA PETITION

Dear Ms. McDaniel,

PLEASE TAKE NOTICE, under Public Resources Code section 21168.5, Communities for a Better Environment ("Petitioner") intends to file a verified petition for writ of mandate and complaint for declaratory and injunctive relief against the South Coast Air Quality Management District ("Air District") in Los Angeles Superior Court. The petition challenges the Air District's approval and certification of the final Negative Declaration for the Phillips 66 Carson Crude Oil Storage Capacity Project ("Project") on December 12, 2014.

The petition seeks a writ of mandate to compel the Air District to comply with CEQA and a writ of mandate directing the Air District and Real Parties in Interest, Phillips 66 and Does 1-20, to take no action in furtherance of this Project unless and until CEQA review is correct and complete. The petit also seeks injunctive relief seeking the Air District's withdrawal of its certification of the Notice of Determination and Project approvals. Finally, the petition seeks declaratory relief stating that the Ai District failed to fulfill its obligation and duty to comply with all applicable statutes and regulations, including CEQA, and that, as a result, all actions taken in connection with approval of the Project are invalid and unlawful.

Sincerely,

Maya Golden-Krasner
Yana Garcia
Staff Attorneys, Communities for a Better Environm

Cc: Dr. Barry Wallerstein, Executive Officer
Kurt Wiese, General Counsel