CBE, Sierra Club, Center, ForestEthics et al. Comments on the Revised Draft Environmental Impact Report for the Phillips 66 Company Rail Spur Extension and Crude Unloading Project

ATTACHMENT A:

Previous Comments and Materials Submitted for the Draft Environmental Impact Report of the Project.

January 27, 2014

Via Email
(p66-railspur-comments@co.slo.ca.us)

San Luis Obispo County Department
of Planning and Building
Murry Wilson
976 Osos Street, Room 200
San Luis Obispo, CA 93408

RE: **Comments to the Draft Environmental Impact Report ("DEIR") for the Phillips 66 Company Rail Spur Extension Project ("Project")**

Dear Mr. Wilson,

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 rail expansion allows the company to get tar sands "dilbit" oils that its throughput increase allows it to convert into engine fuel feedstocks for the Rodeo facility, where a liquefied petroleum gas expansion requires this change in oil processing, and allows some resultant byproducts, otherwise uneconomic to dispose, to be recovered and sold. These interdependent activities could switch the SFR to refining tar sands oil. Phillips 66 discloses this to investors. Its environmental review does not—thereby hiding 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, the Natural Resources Defense Council, Food and Water Watch, San Francisco Baykeeper, and the California Nurses Association, we respectfully submit this comment seeking an adequate environmental review of the 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.

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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 Natural Resources Defense Council ("NRDC") is a national environmental organization with over 1.4 million members and online activists. NRDC's mission is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends.

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 675,000 members and e-activists throughout California and the western 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.

Food & Water Watch works to ensure the food, water and fish we consume is safe, accessible and sustainably produced. So we can all enjoy and trust in what we eat and drink, we help people take charge of where their food comes from, keep clean, affordable, public tap water flowing freely to our homes, protect the environmental quality of oceans, force government to do its job protecting citizens, and educate about the importance of keeping the global commons — our shared resources — under public control.

San Francisco Baykeeper works to reverse the environmental degradation of the past and promote new strategies and policies to protect the water quality of the San Francisco Bay. For two decades, Baykeeper has been the premiere watchdog of the water quality of San Francisco Bay.

California Nurses Association ("CNA"), founded in 1903 is the largest all nurse union in the United States. CNA successfully fought for the first and only statewide law mandating minimum nurse-to-patient ratios in California which saved thousands of lives, among many other laws making hospitals safer for patients. CNA is currently involved in national campaigns to bring economic and political justice and a safe environment in addition to its mainstay of fighting for healthcare justice, and the best nurse contracts in the United States.

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As set forth below in the attached report of Phyllis Fox, Ph.D., PE ("Fox Santa Maria Report"), and in the attached exhibits, the DEIR suffers from numerous deficiencies that render it inadequate under the California Environmental Quality Act[1] ("CEQA") and the CEQA Guidelines[2] ("CEQA Guidelines"). We respectfully request that the County reject the DEIR as an environmental review document, and defer approval of the Project until such time as the DEIR is revised to comply with CEQA.

An EIR is "the heart of CEQA."[3] "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."[4] 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."[5] The DEIR for the proposed Project not only fails entirely to live up to this mandate, but also tramples principles of Environmental Justice.

The DEIR suffers from several inadequacies predicated on two fundamental defects. First, the DEIR fails to disclose the specific quality of oil feedstock that the Project would enable Phillips 66 to process at its Santa Maria facility in relation to that of its current baseline feedstock. The DEIR obscures that the Project will allow the company to partially refine tar sands crude in Santa Maria. Second, the DEIR illegally piecemeals this Project. The DEIR fails to properly acknowledge the inextricable link between this Project and other projects, in particular masking the identity of the "San Francisco Refinery," which is comprised of this Santa Maria facility and its interdependent partner facility in Rodeo, California. Consequently, the DEIR fails to:

(1) provide a stable, accurate and detailed project description, thus undermining every aspect of the impacts analysis;
(2) accurately evaluate numerous Project impacts, including air quality, greenhouse gas emissions, public health and safety, and biological resources;
(3) provide sufficient analysis of cumulative impacts; and
(4) adopt feasible mitigation measures.

Attached Exhibits 1 through 26 support this comment. For these and other reasons detailed herein, the DEIR is inadequate under CEQA. The County must revise the DEIR and recirculate it for public comment.

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[1] Pub. Res. Code § § 21000 *et seq.*
[2] 14 Cal. Code Regs. § § 15000 *et seq.*
[3] *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("*Laurel Heights I"*).
[4] Pub. Res. Code § 21061
[5] *Laurel Heights I*, 47 Cal. 3d at 392 (citations omitted).

I. THE EIR'S PROJECT DESCRIPTION IS INADEQUATE.

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."[6] 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.[7]

Furthermore, "[a]n accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity."[8] 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.[9] The EIR's Project Description fails to meet this standard in three respects: first, it fails to disclose a change to a different, perhaps even lower, quality crude feedstock; second, it illegally piecemeals this Project from Phillips 66's greater project to import "advantaged crude"; and third, it fails to estimate and analyze impacts from the project's duration.

A. The Project Description Fails to Disclose a Change to a Different Quality Crude Feedstock.

This Project will enable Phillips 66 to import and process tar sands crudes at Santa Maria. Yet, the DEIR fails to disclose this fundamental Project characteristic and consequently fails to analyze any associated and evidently significant impacts. The failure to disclose the type and chemical composition of the new crude oils and their resultant potential impacts is a "threshold issue" and "fundamental defect" in environmental review.[10]

Phillips 66 is currently in the process of implementing a series of projects to allow a switch to refining what its management 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..."[11] In May 2013, Phillips 66 EVP Tim Taylor stated in response to a question on bringing heavy Canadian crude oil into California: "Today, we are doing some barge movements down the coast into California on heavy Canadian. You can look in the Northwest to do that. So that's an option that we're going to continue to use and we're looking at expanding that opportunity with some of the logistics things we're putting in place. We're also continuing to move crude by rail in smaller amounts into

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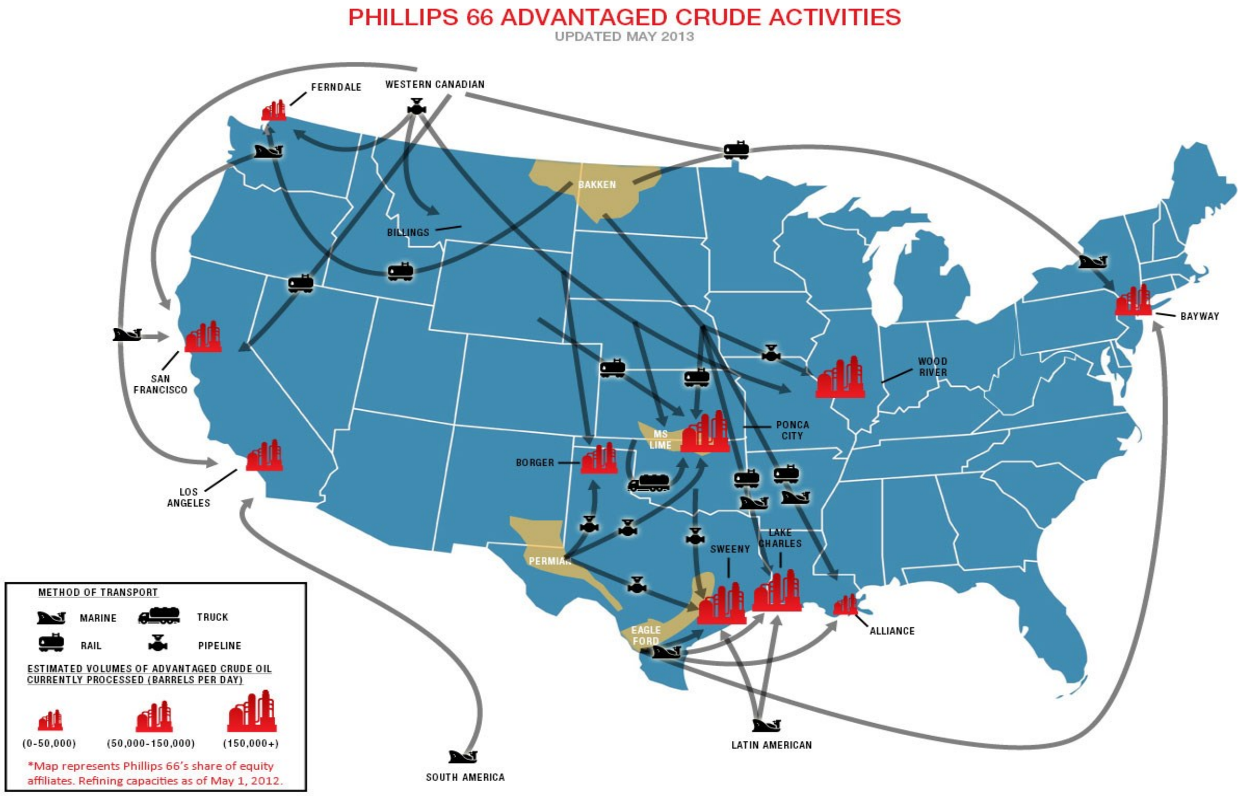
[6] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713, 730, quoting *County of Inyo v. City of Los Angeles* (1977) 71 Cal. App. 3d 185, 193.
[7] *Id.* at 730.
[8] *Id.* (citation omitted).
[9] *See* CEQA Guidelines, §15124 (requirements of an EIR).
[10] *See* eg. Exhibit 25.
[11] September 12, 2013 Transcript, pdf 7: Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/Barclays_091213_Final.pdf, last accessed January 17, 2014.

California and looking at projects really to increase that as well."[12] These heavy Canadian crudes include tar sands crudes.[13] The map immediately below details this strategy.



Phillips 66 map indicating plans to transport Western Canadian crude oil to San Francisco Refinery.[14] Notice that the icon labeled "San Francisco" identifies the San Francisco Refinery, which includes the Santa Maria facility.

These tar sands crudes are cost-advantaged because they are more difficult to process, and, especially in the case of Canadian-sourced oils, they are stranded, with no pipeline access, and must be delivered by rail.[15] Phillips 66 is further incentivized to seek out tar sands blends produced by its own affiliates.[16] In addition, the company has no choice but to seek such an alternative supply of crude oil feedstock. As the DEIR indicates, since 1986, California has steadily faced a declining supply of crude oil.[17] This is particularly the case for the Santa Maria facility and the declining supply in Santa Barbara County.[18] This decline in locally available crude stands in stark contrast to the Santa Maria facility's recent Throughput Expansion that

[12] May 31, 2013 Transcript, pdf 13, Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/PSX-Transcript-2013-05-01.pdf.
[13] *See* Fox Rodeo Report at 9.
[14] Phillips 66 Advantaged Crude Activities: Updated May 2013, last accessed Jan 22, 2014, available at: http://www.phillips66.com/EN/Advantaged%20Crude/index.htm.
[15] Fox Rodeo Report at 9.
[16] *See* Canadian Crude Monitoring Program (www.crudemonitor.ca): Christina Dilbit Blend ("produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility"); and Surmont Heavy Blend (50% owned, and operated by, Conoco Phillips Canada).
[17] DEIR at 6-3; see also Karras Rodeo Report.
[18] *Id.* at 2-27 – 2-30.

enables the Santa Maria facility to process more crude oil. This inconsistency, coupled with the company's publicly stated intention, highlights the company's anticipation to develop a new crude source. Because the Santa Maria facility is currently not equipped to take on the delivery of large amounts of crude by rail, this Project's rail spur is necessary to complete that switch.

Although the DEIR admits that the Project goal is to access a, "full range of competitively priced crude oil,"[19] its analysis attempts to shift the reader's eye to the lighter end of the spectrum of "advantaged crude." Indeed, in spite of the clear indications that Phillips 66 has every intention of bringing down heavy, Western Canadian crudes, including tar sands oils, the DEIR unnecessarily harps on but one type of advantaged crude: Bakken, which is sourced from North Dakota and classified as a "lighter" crude oil feedstock. Although the transport, storage and refining of Bakken poses significant environmental impacts, the source generally contrasts with heavier tar sands crude. Both the DEIR's Introduction and Executive Summary note that the most likely sources of crude would be, "the Bakken field in North Dakota or Canada." The DEIR continues to either cite Bakken solely as an example of crude source, or adds the legally indispensable "and/or Canadian crude" following any reference to North Dakota Bakken.[20] However, the DEIR notes that the Santa Maria facility mainly processes heavy, high-sulfur crude oil.[21]

Bakken Crude is an Unlikely Feedstock for the Santa Maria Refinery

In reality, the Santa Maria facility cannot even handle a lighter crude, such as North Dakota Bakken, for the following three reasons. First, the Project notes that the Santa Maria facility uses two Delayed Coking Units to remove the heavier components from the feedstock.[22] Refining of Bakken does not require coking and would idle Santa Maria's cokers; it would however, require a significant modification and capital investment in most of the existing refining equipment that the DEIR does not disclose.[23] Second, the remaining gases produced in the Delayed Coking Units are sent to amine units sized for the removal of hydrogen sulfide (H_2S), prevalent in heavier crudes, including tar sands.[24] There is little or no H_2S in Bakken. These process capabilities are, thus, unnecessary to refine Bakken; yet, necessary to refine tar sands crude.[25] Third, the size of the unit cars described in this Project is not suitable for the transport of Bakken. If the project proponent's true intent was to solely bring in Bakken sourced crudes, there would be no need for cars the size of what is described in the DEIR. The DEIR should have disclosed the proper purpose of these three project components.

Moreover, changes in the type and amount of semi-refined products sent to Rodeo would result in changes in emissions at Rodeo.[26] The DEIR does not disclose any changes in emissions at the Santa Maria or Rodeo Refineries from processing the rail-imported crude. This omission

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[19] DEIR at 2-1.
[20] See eg. DEIR at ES-3, 2-21, 4.12-21, 2-26. The Project's stated goal is to access competitively priced crude oil from, "North America," which would certainly not preclude Canadian tar sands oils.
[21] DEIR at 2-3.
[22] DEIR at 2-28.
[23] *See* Fox Santa Maria Report at 10.
[24] *Id.*
[25] *Id.* at 7-10.
[26] *Id.*

either eliminates Bakken as the major crude import, pointing to a heavy, higher sulfur crude, such as tar sands, or renders the DEIR deficient for failing to analyze the impacts of the crude switch.[27]

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.[28]

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.[29] 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.[30]

Consequently, the DEIR's omission of this switch to a very different crude oil feedstock violates CEQA.[31] 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 crudes in Santa Maria, unless the DEIR *first* discloses this critical component of the Project.[32] At a minimum, the DEIR should have established whether this Project would result in the company's use of a different or lower quality crude oil feedstock, whether in Santa Maria or any foreseeable location, such as Rodeo, and evaluated such consequent impacts.[33] Until then, the DEIR Project Description is inaccurate, incomplete and renders the analysis of significant environmental impacts inherently unreliable.[34]

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[27] *Id.*

[28] Fox Rodeo Report at 13.

[29] *See* Fox Rodeo Report, Fox Valero Report and Karras Rodeo Report at 11-13.

[30] *See* Chemical Safety Board Interim Report on Chevron Fire, dated 19 April 2013.

[31] *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").

[32] *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).

[33] *Id*.

[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).

B. The Project Is Piecemealed.

CEQA requires that an EIR describe the entirety of a project, including reasonably foreseeable future actions that are part of it.[35] 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."[36] Under this standard, "the facts of each case will determine whether and to what extent an EIR must analyze future expansion or other action."[37] 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.[38] Further, there must be discussion "in at least general terms" of the future activity, even if the project is contingent on uncertain occurrences.[39]

Phillips 66 San Francisco Refinery

As a threshold issue, the County should note that the Phillips 66's San Francisco Refinery 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 DEIR notes, "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."[40] The refining processes at Phillips 66's Santa Maria and Rodeo facilities are integrated to a capacity that neither can achieve alone.[41] Further, Phillips 66 reports these two facilities as a single processing entity, the San Francisco Refinery, to industry and government monitors.[42]

In order for Phillips 66 to implement its "advantaged crude" strategy for the San Francisco Refinery, 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 potentially lock the Rodeo Refinery into a change in oil feedstock processing, most likely tar sands "dilbit" processing.[43] That lower quality feedstock, gas oils and naptha, is produced at Santa Maria and sent to Rodeo by pipeline.[44] However, the

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35 CEQA Guidelines § 15378(a).
36 *Laurel Heights I*, 47 Cal. 3d at 394-396.
37 *Id.* at 396.
38 Id. at 396-397.
39 *Id.* at 398.
40 DEIR at 2-3.
41 *See* Karras Rodeo Report (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.
42 *Id.*
43 *See* Karras and Fox Rodeo Reports.
44 *Id.* and DEIR at 2-29.

Santa Maria facility currently lacks the rail spur required to unload any rail-imported crude to initiate this piecemealed strategy and switch to refining tar sands crude.

(i) The Prior Throughput Expansion is Dependent on this Project.

The DEIR's assertions that the throughput expansion project is unrelated and not dependent on the Rail Spur Project are misleading and incorrect.[45] This Project wholly supports the throughput expansion. A review of the current baseline for refining at the Santa Maria facility shows that the facility is presently operating far below capacity on declining local crude supplies,[46] calling into question any initial need to increase throughput capacity.

Notably, one of the key purposes of this Project is to build the infrastructure to allow crude oil to be imported from distant sources to replace declining local crude oil sources and facilitate a 10% increase in crude throughput, separately permitted. The company's stated intent, noted above, to switch to "advantaged crudes," explains this apparent contradiction. The Santa Maria throughput increase project increases, "…the volume of products leaving the Santa Maria facility for the Rodeo Refinery via pipeline."[47] Nevertheless, the DEIR 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 Rail Spur Project."[48] Yet, the DEIR then admits that, "the only sources of crude oil to meet refinery crude oil demand are from California production, Alaska production, [or] other North American Production that is delivered by truck or rail."[49] This begs the simple question: if local supply is declining, leaving imports, or advantaged North American crudes by "truck or rail," as the only feasible option, 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 DEIR overlaps with the Throughput Expansion explicitly in two regards. First, the evaluation of transport risks associated with this project cites not only to the same analysis performed in the Throughput Increase Project EIR, but that actual EIR itself.[50] Second, the inclusion of the Vertical Coastal Access component is particularly telling. 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.[51] The company provides a detailed discussion of this requirement in this Project's DEIR. The Vertical Coastal Access requirement intersects with this Project. For instance, the DEIR recommends a quantitative risk assessment to determine the minimum distance the coastal access route should be located.[52]

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[45] *See eg.* DEIR at 2-29.
[46] Fox Santa Maria Report at 3.
[47] S*ee* Fox Rodeo Report at 6, citing Throuput Project DEIR at ES-4, 2-25.
[48] DEIR at ES-18.
[49] DEIR at 6-3.
[50] DEIR at 4.7-38.
[51] *See* DEIR at ES-12.
[52] DEIR at ES-16.

Evidently, the public must also be protected from the rail transport of hazardous materials, as well as the facility 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 handling tar sands crude. The two projects are piecemealed and integral to this greater design. Specifically, this Project will allow an increase in crude processing of up to 10,921 BPD.[53] The DEIR did not, but must, analyze all of the impacts of this increase in crude throughput processing capacity, including the increase in emission of processing an additional 10,921 BPD of crude and the increase in emissions of a change in the crude slate itself. The DEIR analyzes none of the impacts associated with a 10,921 BPD increase in crude throughput or the change in crude slate.

(ii) The Phillips 66 Rodeo Refinery is Dependent on this Project.

These two Santa Maria projects, the Throughput Increase and Rail Spur, 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.[54] 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.[55] This increase would be converted into semi-refined products in the Santa Maria facility's distillation units and coker to yield gas oil and naptha, which would be sent to the Rodeo Refinery, where propane and butane would be separated, contributing to the propane/butane slated for recovery by the Rodeo Project.[56]

This Project would then allow the import of cost-advantaged tar sands crude streams that are LPG-rich into the company's Santa Maria facility:

> 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.[57]

Furthermore, analysis of current propane and butane recovery levels at the Rodeo facility highlight the dependence of these projects on one another. The table immediately below[58] summarizes the baseline propane and butane currently recoverable from fuel gas at the Rodeo

[53] *See* Fox Santa Maria Report at 3-4.
[54] *See* Karras and Fox Rodeo Reports.
[55] Fox Rodeo Report at 5, 6.
[56] *Id.*
[57] Fox Rodeo Report at 7.
[58] *See* Supplemental Evidence-C to Appeal of Phillips 66 Rodeo Propane Recovery Project EIR, attached as Exhibit 7.

refinery based on all currently available actual data, which were submitted by Phillips 66 to the Bay Area Air Quality Management District as representative of the project baseline:

Baseline LPG in Rodeo Facility Fuel Gas, December 2009–November 2012

	Units	**Average**	**90th Percentile**
U233 fuel gas flow	(MMSCFD)	29.83	35.21
	(million lbs/day)	1.71	2.02
Propane in fuel gas	(lb/lb fuel gas)	0.2381	0.2381
	(million lbs/day)	0.407	0.481
	(barrels/day)	**2,290**	**2,700**
	(% of project design)	**54%**	**64%**
Butane in fuel gas	(lb/lb fuel gas)	0.2230	0.2230
	(million lbs/day)	0.381	0.450
	(barrels/day)	**1,880**	**2,220**
	(% of project design)	**49%**	**58%**

Project design: 4,200 b/d propane and 3,800 b/d butane; data from DEIR at 3-23. Compressed liquid densities at 60 ºF: 178 lb/barrel propane and 203 lb/b butane; data from EPA's AP 42 Appendix A. All other data from Phillips 66 Air Permit Application attachments provided in Exhibit 7. Conversions from MMSCFD (1 atm., 60 ºF) to lbs/d based on fuel gas MW (21.75 lb/lb-mol), and on propane and butane mass fractions (lb/lb fuel gas shown in table), from Attachment 4. Butane shown includes *n*-Butane and Isobutane.

The Rodeo project aims to recover 4,200 b/d of propane and 3,800 b/d of additional butane.[59] The Rodeo refinery's current recovery, even at the 90th percentile (conditions existing only 10% of the time), only meets 64% of the objective propane goal and 58% of the objective butane goal, based on Phillips' data submitted to air officials. The San Francisco Refinery is a closed circuit. In order for Phillips 66 to meet its project goal in Rodeo, it must utilize the benefits of both the Santa Maria Throughput Increase Project and this rail extension Project. Changes in the amount and type of feedstock would be required to achieve the propane and butane recovery goals.[60]

In addition, the Throughput Increase Project anticipates a 10% increase in throughput capacity, and therefore butane and propane feedstocks.[61] 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. 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 DEIR's assertion that, "no crude oil or refined product would

[59] Id. and see Phillips Propane Recovery Project DEIR at 3-21 and 3-23.
[60] Fox Rodeo Report at 3.
[61] Fox Rodeo Report at 6, citing Throughput Increase Project EIR.

be transported out of the refinery by rail."[62] Further, some tar sands crudes are classified as a semi-refined product,[63] 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.[64] While such a solution may be economic for pipeline delivery systems it could be quite costly if the diluent is returned by rail. However, this same diluent is LPG-rich. 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.

Evidently, plenty of "telling evidence" exists regarding the intimate connection between the proposed Project, the Throughput Increase Project and the Propane Recovery Project. The Rodeo Project depends on the projects at the Santa Maria Facility and vice versa. Consequently, these are connected actions that must therefore be analyzed concurrently with the direct impacts of the proposed Project itself.[65]

Finally, under CEQA, even assuming, arguendo, that the Rodeo Propane Recovery project is not an integral part of this proposed Project, the DEIR 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.[66] The DEIR's admission that Santa Maria supplies partially refined oil to Rodeo by procesing declining local crude supplies established the dependence of the Rodeo facility on the replacement feedstock to be imported by the Project. In its current state, the DEIR's incomplete, unstable and vague project description undermines the validity of the document's environmental impact analyses. The document should be revised to correct these many deficiencies.

C. The DEIR Fails to State a Project Duration.

The expected operational duration of a project is vital to any meaningful assessment of the potential environmental consequences of the project, by both decisionmakers and the public. It is impossible to identify, much less mitigate potential, and foreseeable impacts without information relating to the approximate or known duration of a proposed project's operational components. It is critical for an accurate, stable and finite project description.[67] The DEIR fails to meet this standard.

Although both the initial study and the DEIR include discussions of the Project's anticipated impacts in the context of construction, demolition and general, continued operations,

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[62] DEIR at ES-5.
[63] Fox Rodeo Report at 6.
[64] *See eg.* Exhibit 18 at 7.
[65] CEQA Guidelines, § 15378, subd. (a) agency must evaluate the environmental impacts of the whole of the action.
[66] *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).
[67] *See County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.

both documents omit identification of a precise duration of those Project phases, beyond the construction phase, which is identified as lasting between 9-10 months. This Project implicates a potentially significant period of operation of the proposed rail car tracks, the resultant transport of a different quality and volatile crude feedstock up and down the West Coast, the proposed rail spur's increase in cargo load capacity at the Santa Maria facility, and the use of the new 24-inch above ground pipeline, as well as the 200 mile pipeline stretch to the Rodeo plant. A legally sufficient project description must identify the anticipated duration of these activities.

For example, it matters whether the Project locks the Refinery into receiving somewhere between 80-73 23,500-30,000 gallon railcars, 5 times a day, for a 5 year, 10 year, or 75 year period. Moreover, as explained above, and detailed further throughout these comments, many of this DEIR's shortcomings stem from its failure to analyze the applicant's clear intent and plan to shift the Refinery's overall crude slate. The physical and chemical components and overall composition of the crude that will be unloaded at the Santa Maria facility directly informs the necessary impact, mitigation and alternatives analyses undertaken in this DEIR. As written, however, the DEIR simply states that the crude oil market is too "speculative" to determine whether and how displaced oil sources will be replaced, when necessary *over time*.[68] The Project foresees changing components over time; an analysis of project duration is essential. Such integral points of analysis as the direct, immediate, and foreseeable impacts of the Project are thus obscured entirely, unnecessarily, and in violation of CEQA.[69]

II. THE DEIR'S ANALYSIS OF AND MITIGATION FOR THE IMPACTS OF THE PROPOSED PROJECT ARE INADEQUATE.

A. The DEIR Fails to adequately Analyze and Mitigate the Project's Public Health Impacts.

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."[70] Only with a genuine, good faith disclosure of a proposed project's components, can a lead Agency's analyze the full range of potential impacts of the project, identify, and implement mitigation measures where necessary, prior to project approval.[71]

This Project has the potential to degrade the environment and to cause serious public health impacts. This includes an increased risk of dangers to workers. Indeed, because of the DEIR's failure to include integral project components and the refinery's overall the crude slate change in its analyses, the DEIR often asks the wrong questions, causing the Project's environmental impacts to appear benign, non-existent, or even beneficial. In other instances, the

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[68] DEIR at 2-30 (emphasis added).
[69] See, *County of Inyo v. City of Los Angeles*, *supra*, 71 Cal. App. 3d 185.
[70] *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).
[71] 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.

document lacks the necessary detail to verify the validity of its analyses. Consequently, the DEIR fails to include a sufficient analysis of the Project's impacts on worker and public health and safety, as required by CEQA.[72] The following six issues highlight these inadequacies.

(i) The DEIR either Underestimates or Fails to Address the Project's Toxic Air Contaminant and Hazardous Air Pollutant Emissions.

The DEIR provides no information about existing exposure to Toxic Air Contaminants (TACs) including those identified in the Notice of Preparation (NOP) and Initial Study, and further identified as impacts of particular concern to the SLOAPCD, in comments submitted by the agency. This omission violates CEQA's core requirement that an EIR include an adequate "description of the physical environmental conditions in the vicinity of the project."[73] As the Guidelines instruct, "[k]nowledge of the regional setting is critical to the assessment of environmental impacts."[74] Unless the DEIR adequately describes the public's existing exposure to TACs, decision-makers cannot: (1) understand the scope of the existing TAC problem; (2) measure the Project's new TAC impacts against a baseline of current TAC emissions; (3) evaluate mitigation of those impacts; or (4) intelligently decide whether the Project's approval is worth the exposure increases caused by the project.

Moreover, the DEIR fails to identify, analyze or mitigate known impacts, which will result from the added presence of additional TACS and Hazardous Air Pollutants (HAPs) typically found in the crude blend that will be delivered, processed and transported as a result of this Project. Some of these TACs and HAPs, that are of particular concern to both the United States Environmental Protection Agency (EPA) and the California Air Resources Board (CARB), yet are either omitted or inadequately analyzed in the EIR, include the following: benzene, sulfur compounds, toluene, xylenes, inorganic lead and other metals including Nickel, diesel particulates.

(ii) The DEIR Fails to Adequately Mitigate Potential Toxic Asbestos Impacts From Both the Construction and Operations Phases of the Project.

The Initial Study identifies naturally occurring asbestos and asbestos containing material as two sources of potential toxic contaminants, resulting in a significant impact on the environment.[75] Both potential sources are identified as toxic contaminants of particular concern to the SLOPACD; triggering notification and survey requirements to ensure that known, severe human health impacts do not flow from construction, demolition and ongoing operations related to the rail spur project.[76] Such concern was also based on the fact that such activities would

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[72] *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.").
[73] CEQA Guidelines § 15125(a).
[74] *Id*. § 15125(c).
[75] NOP and Initial Study, 8
[76] NOP and Initial Study, Appendix C, Comments – Agency Referral Responses, SLOACPD Response to Initial Study and Mitigated Negative Declaration, at pp. 4-5.

occur in “close proximity to multiple sensitive receptors.”[77]

The DEIR addresses potential impacts from asbestos releases into the air and surrounding environment in the mitigation table, at IST-13, by simply “covering” during construction. However, the DEIR makes no mention of mitigation measures applicable to demolition, or ongoing operations and their resulting disturbance to the surrounding area containing asbestos. As of updates made in 2011, however, CARB has identified asbestos, including naturally occurring asbestos as a toxic contaminant for which there is no safe level of exposure; thus, merely “covering” construction projects, without addressing ongoing disturbances, particularly in light of the close proximity of multiple sensitive receptors, is an inadequate mitigation measure.

(iii) The DEIR Fails to either Adequately Identify or Mitigate Diesel Particulate Matter Emissions During both Construction and Operations Phases of the Project.

The DEIR admits that both the operational activities and the construction phase of the project will result in emission levels above SLOAPCD thresholds for diesel particulate matter (DPM) a state recognized TAC.[78] The DEIR classifies such impacts as falling in both the Class I and Class II impact categories. The first, Class I, are impacts that are both significant and unavoidable; and second, Class II, are impacts that are potentially significant, but less than significant with mitigation. While these classifications appear to recognize the severity of the potential impacts that may be caused by DPM, the analysis contained in the DEIR falls short of fully identifying the extent of impacts that will be caused by an increase in DPM emissions. Furthermore, the DEIR’s analysis is misguided by the fact that it fails to state an accurate baseline level of the Santa Maria facility’s current, and foreseeable process emissions. Finally, the DEIR fails to account for the increase in emissions that will come from the Refinery’s undisclosed change in crude slate, and fully fails to identify the Project’s increase in emissions at the Rodeo facility, as a result of the DEIR’s piecemealed analysis.

An Improper Baseline

In section 4.3.1.4, the DEIR generally states that “toxic emissions” including DPM, are associated with the Refinery’s current daily operations.[79] While it does not state a precise level for those emissions, the DEIR goes on to provide data from a toxic release inventory used to conduct analyses for the last Health Risk Assessment (HRA) done by Phillips 66, pursuant to the requirements of AB2588.[80] That HRA was conducted in 2007, was based on an emissions inventory taken in 2004, and was used for the Throughput Increase Project Health Risk Analysis in 2010. Although the 2004 data was updated in 2010, in order to assess the potential impacts from the Refinery’s Throughput Increase Project, it fails to state a proper baseline for the purpose of identifying the current level of DPM emissions.

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[77] *Id*.
[78] DEIR, 4.3-36; *and see*, California Air Resources Board Toxic Air Contaminant Identification List, available at: http://www.arb.ca.gov/toxics/cattable.htm#Note 1, last accessed, Jan. 26, 2014.
[79] DEIR 4.3- 18.
[80] *Id*.

As described in more detail, *infra*, the CEQA Guidelines state that the baseline for a project should consist of "the physical environmental conditions … as they exist *at the time the notice of preparation is published*."[81] The DEIR's reliance on emissions inventories from 2004, even as updated in 2010, not only fails to meet CEQA's requirement that a baseline reflect conditions at the time of the NOP, but such data also fails to provide an accurate depiction of the refinery's true emission levels throughout the life of the Project. The DEIR admits that as of 2013 the Refinery's throughput levels and operating capacity do not reflect the modifications of the Throughput Increase Project.[82] Setting aside the contradiction embodied by the DEIR's reliance on data used for the purpose of that Project's environmental analyses, when at the same time it fails to disclose the relationship between the two projects, the DEIR states that the Refinery emissions levels are based on operations up to the facility's full permitted throughput capacity. This alone appears to violate CEQA's requirement to use actual, rather than permitted emissions, as the project baseline.[83] Yet, the DEIR goes on to state that such emissions levels do not reflect the change in operational capacity enabled by the Throughput Increase Project. Thus, the permitted levels, even as of 2013, still fail to provide an accurate depiction of the existing environmental conditions, of this Project, as this Project is integrally related to the Throughput Increase Project.[84]

Finally, as a result of the DEIR's failed analysis of the range of potential DPM emissions the DEIR underestimates the mitigation necessary to prevent harmful impacts caused by DPM. For example, the DEIR provides that it will address the increase in diesel emissions during construction and operations by watering exposed areas 3 times per day for 61% fugitive dust control; that it will require reduced vehicle speeds to 15 mph and the use of Tier 3 engines with DPM on construction equipment above 100 hp.[85] It further states that it will confer with SLOAPCD, prior to and during Project operations to develop plans to address the Project's above threshold emissions levels, including achieving off site emissions reductions, in order to account for those emissions that surpass the County's applicable threshold levels.[86] As noted throughout this comment, such deferred mitigation activities are improper under CEQA.

(iv) The DEIR Fails to Identify or Mitigate Additional Impacts of Emissions Resulting from the Project's Change in Crude Slate.

This Project enables the Santa Maria facility to receive new sources of crude, whose chemical composition, including chemicals mixed to enable transport and further processing at the Rodeo facility remain undisclosed, and therefore, cannot be analyzed for their impacts.[87] This leaves such impacts without mitigation or alternatives analyses, thwarting the entire purpose of the document, in violation of CEQA.[88]

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[81] CEQA Guidelines, 14. Cal. Code Reg. § 15125(a).
[82] DEIR 4.3-21.
[83] *See* Exhibit 25.
[84] *See supra* Section I.A.
[85] DEIR 4.3-35.
[86] *Id*.
[87] *See supra* and Fox Santa Maria Report.
[88] *See Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs*, *supra*, 91 Cal.App.4th 1344, 1355

In addition to generally requiring more energy, and power generation to refine, the composition of tar sands crudes is chemically different from other heavy, locally sourced crudes, currently processed at the Santa Maria facility, and/or transported by pipeline to Rodeo. By their composition, tar sands are heavier, denser, and have higher sulfur contents than locally sourced crudes.[89] As outlined above, tar sands crudes are distinct from even the heaviest of crudes currently processed at the Refinery, 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. If released, these air pollutants amount to increased emissions that would result in significant public health and air quality impacts not addressed in the DEIR.

As a result, the DEIR fails to account for significant increases in overall emission estimates, including those of DPM, potent carcinogens such as benzene, toxic sulfur compounds that would individually and cumulatively cause malodors, and degrade ambient air quality; and a dramatic increase in incidents of accidental releases adversely affecting the health of workers and residents throughout the County, and even along the rail route up and down the West Coast. Furthermore, the high acid levels in these crudes and their semi-refined products would accelerate corrosion of refinery components, contributing to equipment failure, more accidental releases, and again, risking harm to both worker and public health and safety.

Bitumen Chemical Composition

Bitumen is composed of higher molecular weight chemicals, including large amounts of benzene, toluene, xylenes, and other heavy metals, present in both state and federal toxic emissions inventories, and therefore of particular concern to both federal and state regulatory agencies.[90] Benzene has a high cancer potency and is known to cause severe reproductive, developmental and immune systems impacts at even low exposure levels.[91] Systemic benzene poisoning, a long term exposure risk, includes the potential for severe hemorrhages, and may at times result in fatality.[92] Concentrated, acute exposure levels have also been known to cause headaches, and nausea.[93] 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.[94]

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

[89] Fox Santa Maria Report at 26.
[90] *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.
[91] Determination of Acute Reerence 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, Jan. 26, 2014.
[92] *Id*.
[93] *Id*.
[94] California Air Resources Board, Toxic Air Contaminant Identification List, available at: http://www.arb.ca.gov/toxics/cattable.htm#Note 1, last accessed, Jan. 26, 2014.

heavy crude oil, including even the heaviest of "American crudes," which, according to Phillips 66, comprise the majority of the crude slate currently processed at the Refinery.[95] The environmental damage caused by these contaminants, when released includes acid rain; harmful bioaccumulation of the contaminants; the formation of ground-level ozone and smog; visibility impairment; odor impacts affecting residents near the Refinery; accidental releases due to corrosion of refinery equipment; and depletion of soil nutrients.[96]

Currently, the level of bitumen present in the refinery's overall crude slate is as low as 2 - 7%.[97] Given this Project's overall components, including those that are unaddressed in the DEIR, such as the Throughput Increase Project and its resulting dramatic increase in process capacity at Santa Maria, this level of tar sands crude present in the overall crude slate will increase dramatically. The Project may in fact increase the import of heavy tar sands bitumen crudes by up to the entire permitted capacity of the Refinery.[98] This means, that there will be a remarkable increase not only in the content of lead and other metals listed above contained in the crude itself, but also in derivative coke and coke products, transported out of the refinery.[99] 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, including rail cars and pipelines used for transport.[100] Nevertheless, the DEIR fails to identify, analyze or mitigate the wholly foreseeable Project emissions of these contaminants.

For instance, the DEIR does not disclose BTEX concentrations either in the baseline crude slate or in the range of crudes that will be imported by way of the Project.[101] BTEX levels in diluent generally range from about 27,000 ppm to 60,900 ppm.[102] The BTEX in dilbits, blended from these diluents materials in turn, ranges from 8,000 ppm to 12,300 ppm.[103] Again, because of the high vapor rate that is characteristic of the diluents, and thus also characteristic of dilbit, dilbit will likewise quickly evaporate from any unseamed openings. Thus, whether because of pure diluents or the blended dilbit arriving to the Santa Maria facility by way of rail, and likewise being processed, or transported out of the facility by way of pipeline, a remarkably high level of hazardous toxic materials exists, well above the current baseline level that is implicated by this Project, and completely beyond the contents of the DEIR.

The DEIR's current, single mass fraction crude vapor speciation profile contained in the document's impacts analysis is wholly insufficient to address the potential risks associated with the increase in dilbit at the Refinery.[104] In order to assess and mitigate the potential impacts from the increased concentration of TACs, and HAPs, and their associated risk of causing serious harm to human health and environment, the DEIR should, at a minimum, include the amount of

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95 Fox Santa Maria Report at 29.
96 *Id*.
97 Fox Santa Maria Report at 2.
98 *Id.* at 28.
99 *Id.* at 29.
100 *Id.* at 22.
101 *Id.* at 22
102 *Id*.
103 *Id*.
104 *Id.* at 23.

diluents needed to enable efficient delivery and transport of tar sands crude into and out of the Santa Maria facility.

Overall, a switch in crude slate directly implicates additional HAPs to be emitted at many 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.[105] Moreover, when any amount of dilbit is released, the substance will generally create spills far more difficult to clean, or remedy, than those caused by even the heaviest of locally sourced crudes.[106] When held in a storage tank, pipe or rail car, diluents alone can also rapidly evaporate and escape through any unseamed openings[107] – another set of significant impacts the DEIR leaves unidentified, unaddressed and unmitigated.

(v) The DEIR Fails to Identify Risks to Worker Health and Safety.

The DEIR fails to adequately identify the health risks posed to on-site workers as a result of the Project. While the DEIR states that there are health risks associated with exposure to carcinogenic compounds at the refinery, the DEIR fails to provide an assessment of how the increased exposure to carcinogens, stemming from the project, will impact on-site workers.[108] Thus, the DEIR further fails to identify these critical potential impacts.

Workers at both of Phillips 66's San Francisco Refinery facilities will bear the brunt of the burden caused by vapor and other emissions of TACs and HAPs from various transport and refinery equipment. On-site workers will also be on the frontlines of any accidents, spills or other hazards caused by the Project, and therefore are particularly susceptible to suffer from the most serious health impacts, that may stem from this Project.[109] Because of the TACs and HAPs present in the tar sands bitumen crudes and in their blended diluents, the County must require a full HRA analysis that accounts for the change in crude slate. Currently, the DEIR cites to the HRA used for the Throughput Increase Project, yet, fails to acknowledge the relationship between the two Projects. Such a blatant contradiction, that also confirms that these projects are piecemealed, should not stand. The DEIR ignores impacts to workers and the County should require a revised HRA that includes the added TAC and HAP burdens resulting from the combined components of the Throughput Increase, Propane Fuel Recovery, and Rail Spur Projects, prior to approving any EIR document, and certainly prior to Project approval.

(vi) The DEIR Fails to Identify Cumulative Impacts to Public Health.

The DEIR omits a necessary analysis of cumulative impacts of the Project, one of CEQA's most vital requirements.[110] An EIR must "discuss cumulative impacts of a project when the project's incremental effect is cumulatively considerable."[111] Furthermore, a lead

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[105] *Id.* at 16.
[106] *Id.* at 21.
[107] *Id.*
[108] DEIR, 4.3-48.
[109] Fox Santa Maria Report at 24.
[110] *See* Pub.Res.Code § 21082 (referring to the CEQA Guidelines §§ 15130(a)(1) and 15355 for the applicable definition of cumulative impacts); *see also*, *Bozung v. Local Agency Formation Commission* (1975) 13 Cal.3d 263, 283
[111] CEQA Guidelines § 15130(a) (emphasis added).

agency must find "that a project may have a significant effect on the environment" when "[t]he project has possible environmental effects that are individually limited but cumulatively considerable." [112] The Guidelines define "cumulatively considerable" to mean "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."[113] The purpose of this analysis is to avoid considering projects in a vacuum, wherein seemingly benign impacts could lead to severe environmental harm, in light of the environmental context.[114] The DEIR must, therefore, "demonstrate that the significant environmental impacts of the proposed project were adequately investigated[,] discussed[,] and … considered in the full environmental context," including existing pollution burdens in the areas that are directly impacted by the Project.[115]

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.[116] 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 communities.[117] 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.[118] 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

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[112] CEQA Guidelines § 15065(a).
[113] *Id.*
[114] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th at 720.
[115] CEQA Guidelines § 15125(c).
[116] 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, last accessed, Jan. 26, 2014; and Zip code Results, Rodeo, available at:
http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56, last accessed, Jan., 26, 2014.
[117] *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.
[118] 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, last accessed, Jan. 26, 2014.

alone.[119] 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.[120] Guadalupe is identified as a linguistically isolated city, and similar to Nipomo has a high concentration of hazardous waste facilities.[121] It also bears the impacts of a high concentration of emissions from other concentrated pollution stationary sources, such as the Santa Maria Refinery.[122] 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. [123]

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.[124] Moreover, Rodeo also suffers from a high rate of low birth weights and asthma, ranking in the top 1 and 16% for each, respectively.[125]

The particular vulnerabilities of these communities, and the existing pollution burdens that exist in each, even without the added impacts of the proposed Rail Spur Project, 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. As detailed above, the Project's emissions and impacts analysis is incomplete, as a result of the DEIR's failure to disclose information relating to the Refinery's overall shift in crude slate. Even absent an analysis that includes the Refinery's change in crude, those emissions that are currently identified in the DEIR as being less than significant, are not analyzed in the context of the existing pollution burdens in either Santa Maria and its surrounding communities, or Rodeo. This analysis is an integral component of CEQA, one that the DEIR illegally omitted.[126]

Overall, the DEIR's failure to disclose the exact qualities of its projected and foreseeable feedstock switch preclude any meaningful analysis of the impact of this Project on worker and community health. The DEIR simply does not provide enough information. Even if the Project were to implement the DEIR's claimed Bakken feedstock, Bakken crude is a light and volatile crude with a high API gravity and very low sulfur content, significantly distinct from the current crude feedstock processed at the Refinery, and also distinct from tar sands crudes.[127] When refined, it yields very little residuum, which is generally used for coker feeds, but it yields large amounts of gasoline.[128] If the crude slate were switched to Bakken, combustion emissions at the

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[119] 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, last accessed, Jan 26, 2014.
[120] *See* OEHHA Cal Enviro Screen 1.1, *supra*, and *see, Id*.
[121] *Id*.
[122] *Id*.
[123] *Id*.
[124] 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.
[125] *Id*.
[126] CEQA Guidelines §§ 15064(d), 15125(c); *see also, Kings County Farm Bureau*, 221 Cal. App. 3d 692, 729.
[127] *Id*. (citations omitted)
[128] Fox Santa Maria Report at 9.

Santa Maria Refinery may decrease overall, however, VOC and other HAP emissions would significantly increase, as well as the risks to worker and public health and safety.[129]

B. The DEIR Fails to Adequately Analyze and Mitigate the Project's Air Quality Impacts.

The EIR's analysis of the Project's criteria pollutant impacts is riddled with errors. We highlight five: 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, it underestimates or ignores altogether emissions of criteria pollutants. Third, the Project relies on an illegal use of Emission Reduction Credits. Fourth, the EIR's analysis completely underestimates indirect emissions. Fifth, the EIR's analysis is predicated on a faulty and illegal baseline. 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 DEIR 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.[130] However, it is clear that the air quality impacts of the Proposed Project will regularly extend far beyond the county line, or even other areas that the DEIR makes brief mention of, and the DEIR fails to account for that.

The study area of an EIR must include "the area which will be affected by a proposed project."[131] 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."[132] 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."[133]

By employing an artificially constrained study area, the DEIR fails to assess the air quality impacts of operational emissions outside of San Luis Obispo County. Although the DEIR does calculate both GHG and criteria emissions outside of the County, it neither evaluates the significance of these emissions, nor discusses any mitigation measures. This is particularly problematic. For example, locomotive emissions outside of the County will be significant—the DEIR calculates locomotive GHG emissions outside of the County as over 60,000 $MTCO_2E$, which accounts for nearly 80% of the total operational GHG emissions of the proposed project.[134] Similarly, the criteria emissions from locomotives outside of San Luis Obispo County

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[129] *Id.* at 10.
[130] See DEIR at 4.3-1
[131] 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").
[132] *Save the Plastic Bag Coalition v. City of Manhattan Beach* (2011) 52 Cal.4th 155, 173.
[133] Muzzy Ranch Co. v. Solano Cnty. Airport Land Use Com. (2007) 41 Cal. 4th 372, 387.
[134] See DEIR at 4.3-50, Table 4.3.15.

are significant.[135] Among other emissions, the DEIR fails to evaluate the impacts of 160 tons of NO_x, 5 tons of PM_{10}, and nearly 25 tons of CO that will be emitted each year in California outside the County borders.[136]

By artificially limiting the geographic scope of the analysis to air pollutants emitted within the boundaries of San Luis Obispo County, the DEIR substantially underestimates the significant air quality impacts of transporting crude oil by rail from oilfields across North America to the Sana Maria facility. The DEIR should be revised to evaluate the Project's emissions outside of the County, and to discuss mitigation for those emissions.

(ii) The DEIR Does Not Analyze Emissions from All of the Project's Components.

The DEIR fails to assess emissions from all components of the Project. Most blatantly, the DEIR fails to assess the air quality impacts of the San Francisco Refinery as a whole, and includes no analysis of the emissions that will be caused at the Rodeo component as a result of the rail spur extension 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.[137] As discussed *supra* in Part I, 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.

Most importantly, because the DEIR does not disclose the quality of crude oil that will be brought to the San Francisco Refinery as a result of the rail spur expansion, the DEIR cannot analyze the severe air quality impacts that will result from processing different-quality crude. The proposed rail spur extension will allow the San Francisco Refinery to import different or lower-quality crude oil from oilfields throughout North America.[138] 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, which is not discussed in the DEIR.[140] Each of these flaring episodes comes with associated and extremely high levels of additional pollution.

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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[135] See DEIR at 4.3-44, Table 4.3.13.
[136] See DEIR at 4.3-44, Table 4.3.13.
[137] *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.
[138] See DEIR at 2-21.
[139] *See* Karras Decl. (Rodeo).
[140] *See* Karras Decl. (Rodeo).

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 DEIR does not analyze these effects, and consequently the DEIR also fails to discuss mitigation measures for these impacts.

The EIR process for 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.

(iii) The DEIR Inappropriately Relies on Emission Reduction Credits Requested by the Rodeo Facility.

The DEIR underestimates the SO_2 emissions of the Project. The DEIR fails to disclose an application for Emission Reduction Credits ("ERCs") that would likely result in future SO_2 emissions increases at Phillips 66's San Francisco Refinery. The application was filed for the Rodeo facility, but it is equally relevant here because the Rodeo and Santa Maria facilities are, by Phillips 66's own admission, the two component parts of the San Francisco Refinery.

Phillips 66 asserts that its Rodeo Propane Recovery Project will result in a reduction in SO_2 emissions, and has requested 174.7 tons per year of SO_2 ERCs for that reduction.[143] According to Phillips 66, "[o]f this amount, 7.61 tpy will be used to offset project SO_2 increases so that there will be no net increase in SO_2 emissions from the project (see Table 3-1). The remaining 167.1 tpy of SO_2 (174 tpy minus 7.61 tpy) will be banked as ERCs."[144] The assertions in this application are contrary to the assertions in the EIR for the Rodeo Propane Recovery Project, which claims that the Rodeo project will reduce refinery-wide SO_2 emissions "by at least 50%."[145] Banking ERCs equal to the claimed emission reduction would allow the refinery to increase its SO_2 emissions in the future, thus negating any claimed SO_2 reduction benefits.

The DEIR must identify and analyze the impacts of these SO_2 ERCs in order to capture the full air quality impacts of the Project, inextricably linked to the Rodeo facility. The failure to acknowledge and assess these impacts is a clear violation of CEQA's mandate to identify and avoid the significant effects of a project on the environment.

(iv) The DEIR Fails to Adequately Analyze Indirect Emissions.

CEQA requires an EIR to consider both direct and indirect impacts of a proposed project.[146] 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."[147] The scale of the Project's

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[141] *See* Karras Decl. (Rodeo).
[142] *See* Karras Decl. (Rodeo).
[143] *See* Karras Decl. (Rodeo).
[144] Air Permit Application at 17, Section 3.4 (Air Permit App Sections 1–3).
[145] Rodeo PRP EIR at ES-2, 3-5, and 4.3-19.
[146] CEQA Guidelines, 14 Cal. Code Reg. § 15358(a).
[147] CEQA Guidelines, 14 Cal. Code Reg. § 15358(a)(2).

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."[148] Thus, the DEIR 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.[149]

The DEIR does not acknowledge a switch to a lower or different quality crude feedstock and therefore does not address the indirect emissions associated with that switch, for example, greenhouse gas emissions from crude source demand activities such as extraction and front-end refining and diluting.

Similarly, the DEIR does not adequately analyze the substantial air quality impacts associated with the transport of crude oil from new sources across North America. The refinery currently receives all crude oil for processing by pipeline,[150] while the Project proposes to import crude oil by rail from "oilfields throughout North America."[151] The Project would result in up to 250 trains per year moving from Canada or North Dakota to Northern California, through some of the most densely populated regions of the state, along the coast to the Santa Maria Refinery in Central California.[152] Evidently, the air quality impacts, for instance of GHGs, of such extensive rail transport as compared to current impacts of local pipeline transport will be substantial and severe. The DEIR fails entirely to assess the significance of these impacts or to propose mitigation for these impacts. By limiting the study area to the boundaries of San Luis Obispo County, as discussed *supra* in Part II.B.1, the DEIR 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.

Additionally, as noted above, the DEIR fails to account for emissions associated with the Rodeo facility. These include increased criteria pollutant and GHG emissions resulting from the processing of different or lower-quality crude, 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 DEIR 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.

(v) The DEIR Uses an Inappropriate Baseline Environmental Setting, Rendering its Air Quality Analysis Unreliable.

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148 Kings County Farm Bureau v. City of Hanford (1990) 221 Cal. App. 3d 692, 717.
149 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.").
150 DEIR at 2-27.
151 DEIR at ES-3, 1-4, 2-21.
152 See DEIR at 2-21 (estimating a maximum of 250 trains per year).

The baseline for a project consists of "the physical environmental conditions in the vicinity of the project, as they exist at the time the notice of preparation is published."[153] As the DEIR acknowledges, emissions resulting from current refinery operations are a key component of baseline air quality.[154] However, instead of providing data on current refinery emissions, the DEIR instead relies on the emissions limitations in the refinery's permits to establish baseline air quality.[155]

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.[156] 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.[157] 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.[158]

The DEIR provides no information about the actual emissions levels at the Refinery, and thus fails to provide sufficient information to establish an appropriate baseline environmental setting. The DEIR should be revised to provide this information and an accurate and informative baseline as required under CEQA review.

C. The DEIR Fails to Adequately Disclose, Analyze or 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 or, "information about how adverse the adverse impact will be."[159] Without this information, it is impossible for County decision makers and the public to evaluate the extent and severity of the Project's impacts relevant to public safety. The DEIR fails to meet this burden in three respects: (1) it continues to omit relevant and indispensable information regarding crude quality and therefore never addresses resultant safety impacts; (2) it illegally defers mitigation in relying on safety precautions and anticipated plans that are not yet approved; and (3) it includes a flawed and under-estimated analysis of the risk of oil spill or train car derailment.[160] The DEIR therefore fails to provide any currently real and enforceable measures and performance standards and can provide no assurance the Project's impacts related to hazards would not be significant, or that they would be mitigated at all.[161]

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[153] CEQA Guidelines, 14. Cal. Code Reg. § 15125(a).
[154] See DEIR at 4.3-17 to 4.3-22.
[155] DEIR at 4.3-18 to 4.3-19.
[156] Communities for a Better Env't v. S. Coast Air Quality Management District (2010) 48 Cal. 4th 310.
[157] CBE v. SCAQMD, 48 Cal. 4th at 320.
[158] *Id.*
[159] *Santiago County Water District v. County of Orange* (1981) 118 Cal. App. 818, 831.
[160] *See* DEIR at 4.7.
[161] *See Sacramento Old City Ass'n v. City Council* (1991) 229 Cal. App. 3d 1011.

Scope of Analysis/Federal Preemption

As an initial matter, the DEIR's Study Area and Scope of analysis of public safety risks is unnecessarily limited to the vicinity of the Rail Spur.[162] Although the DEIR provides a detailed description of catastrophic failure scenarios, it does not analyze whether those impacts would prove significant, to any degree of specificity, in regards to this Project. The DEIR's analysis of risks to public safety ends with the Santa Maria facility boundary.[163]

The implications of this Project, however, include approximately 400 tanker cars per week moving up and down the West Coast, likely containing extremely hazardous tar sands crude, or highly flammable Bakken.[164] The DEIR simply analyzes the risks of spill and derailment in regards to the unloading facility at the refinery and in the vicinity of the Union Pacific Railway right of way.

The DEIR claims that certain train movements may be "preempted from local and state environmental regulations by federal law under the Interstate Commerce Commission Termination Act ("ICCTA") of 1995 . . . ." However, ICCTA does not preempt CEQA. Indeed, no published decision has so held. Accordingly, the DEIR must analyze *all* hazard and public safety impacts created by the Rail Spur Project, regardless of whether they occur on the project site or not.

(i) The DEIR Fails to Discuss the Public Safety Risks of Refining a Different or Lower Quality Crude Oil Feedstock.

The DEIR's failure to disclose the company's switch to crude with a significantly different chemical composition, and even to tar sands crude, renders the instant analysis of public safety impacts inherently flawed. It fails to identify the varied risks associated with refining, storing and transporting these crudes.

(a) The DEIR does Not Adequately Consider Accidental Releases at the San Francisco Refinery.

It is uncertain whether the Santa Maria facility can handle the unique chemical composition of tar sands crudes without significant upgrades. Higher acid and/or sulfur content in a crude may increase the risk of corrosion to refinery equipment and pipes, which in turn can lead to leaks, explosion or fire.[165] There is no assurance that required metallurgical upgrades have occurred at the Santa Maria facility to cope with the different composition of "advantaged

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[162] DEIR at 4.7-1, 4.7-2. Section 4.7.1.1 anticipates the scope of review: "The area that could be impacted by a release also includes all rail routes in the County and any routes associated with existing trucking of crude oil or associated facility hazardous materials." However, the DEIR, after an extensive review of the applicable Federal, State and local laws, merely analyzes project impacts immediately within the vicinity of the rail spur (section 4.7.4).
[163] The company proposes only two mitigation measures (registration of railroad crossings within the Santa Maria facility with the Federal Department of Transportation and installation of crossbucks at those crossings, DEIR at 4.7). This places full reliance on the federal government and ignores explicitly delegated authority outlined throughout the DEIR, for instance the CPUC's regulation in regards to railroads.
[164] See Fox Rodeo Report and DEIR at 4.12-21and 2-21.
[165] *See* http://www.dir.ca.gov/DIRNews/2013/IR2013-06.html

crude." Such refinery infrastructure changes are extensive and not required by any regulatory framework. As noted above, changes in crude slate at the Chevron Refinery in Richmond suggests that failure to perform required metallurgical upgrades can lead to catastrophic accidents.[166]

A crude slate change could result in corrosion, a root cause of significant accidental releases, even if the crude slate is within the current design slate basis, due to compositional differences. In fact, although the sulfur composition at Chevron Richmond remained within the design range,[167] the gradual and significant change over time caused 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 release sent 15,000 people to nearby hospitals and created huge black clouds of pollution billowing across the Bay. It also put workers at the unit in grave danger, with several escaping the gas cloud and inferno narrowly.

Incidents such as those that occurred at the Chevron Richmond Refinery confirm that refining oil is an inherently dangerous process. According to the report "Improving Public and Worker Safety at Oil Refineries" prepared by Governor Jerry Brown's Office, every week, the U.S. Department of Energy receives reports on process safety incidents in the U.S. refinery industry.[168] The week that ended March 14, 2013 had 26 reported incidents, including unplanned flaring at the Torrance, California Exxon Mobil Refinery; an unplanned shut-down of the hydrocracking unit at Valero's Benicia, California facility; and the unexplained restart of a major electrical unit at the Chevron Refinery in Richmond, California.[169] Recent news reports tell of multiple catastrophic events that have resulted in fatalities, serious injuries, and devastating environmental effects.[170] The DEIR fails to account for any preventative or responsive precautions to address the Project's goal of accessing a wide range of "advantaged crudes."

(b) The DEIR does Not Adequately Consider the Impacts of Transport of Tar Sands Crude by Rail.

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[166] 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/.

[167] US Chemical Safety and Hazard Investigation Board, 2013, 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.").

[168] *See* Improving Public and Worker Safety at Oil Refineries Draft Report of the Interagency Working Group on Refinery Safety Governor Jerry Brown, dated July 2013.

[169] *Id.*

[170] *See* Associated Press, *Crews slowed by Heat in attacking Calif. rail fire*, NBC News, Aug 24, 2011 http://www.nbcnews.com/id/44259169/ns/us_news-life/t/crews-slowed-heat-attacking-calif-rail-fire/; and Bret Schulte, *Oil Spill Spotlights Keystone XL Issue: Is Canadian Crude Worse?*, Apr. 4, 2013. http://news.nationalgeographic.com/news/energy/2013/04/130405-arkansas-oil-spill-is-canadian-crude-worse/; and Marianne Lavelle, *Oil Train Crash Probe Raises Five Keys Issues on Cause*, National Geographic, Jul. 11, 2013. http://news.nationalgeographic.com/news/energy/2013/07/130711-oil-train-crash-five-key-issues/; and David Boroff, *At least eight injured, five critically, as explosions rock Blue Rhino propane gas plant in Florida*, National Geographic Jul. 30, 2013, http://www.nydailynews.com/news/national/15-missing-florida-explosions-article-1.1412355; and Matthias Gafni, *Benicia: Three Valero refinery rail cares filled with coke derail*, Contra Costa Times, Nov. 5, 2013, http://www.contracostatimes.com/news/ci_24458813/valero-refinery-rail-car-derails-benicia.

The Federal Railroad Administration has expressed concern about an increasing number of severe corrosion incidents found in rail tank cars and service equipment.[171] Further, there is a history of major spills, derailments and explosions of hazardous materials along California rail routes.[172] The New York Times even recently published an article: "Accidents Surge As Oil Industry Takes the Train."[173] Although the DEIR skims the surface of analysis of such impacts,[174] it fails to do so in regards to the Project itself, and in particular to the transport of tar sands and other crudes.

The DEIR does highlight the tragedy in Lac-Mégantic, Canada. Several derailed tank cars spilled oil resulting in multiple explosions and fires causing 47 fatalities, extensive damage to the town center and precipitated the evacuation of about 2,000 people from the surrounding area.[175] The transport of crude by rail also implicates significant hazards to public safety. Bakken itself is particularly flammable, and was the feedstock transported in Lac-Mégantic, but tar sands crude also contain the very dense and toxic diluted bitumen that the rail cars are likely to carry. These oils in particular pose an especially serious environmental and public health threat when accidentally released into the environment. The EPA recently noted that spills of diluted bitumen require a different response action or equipment than for conventional oil spills.[176] Dilbit spills are simply more difficult and more expensive to clean up.[177] A 2010 spill of tar sands oil in Michigan has left substantial amounts of the oil on the river bottom to this day, and a $1 billion clean-up continues.[178] Public health officials found numerous acute health impacts lasting for days and spanning numerous areas: Cardiovascular, dermal, gastrointestinal, neurological, ocular, renal, respiratory and other impacts.[179] Alternatively, should the project rely on rail transport of Bakken crude, equally serious unmitigated spill, fire and explosion hazards could result, albeit by somewhat different chemical mechanisms and associated safety system gaps, as the Lac–Mégantic incident examples tragically. The DEIR fails to sufficiently analyze any potentially similar impacts throughout California as a result of this Project, and completely omits any discussion beyond the Project's immediate vicinity, for instance, impacts resulting from increased traffic, train idling and old ageing train cars not equipped for these hazardous materials.

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171 See http://www.fra.dot.gov/eLib/details/L04717.
172 For example, there was a very major spill into Upper Sacramento River in 1991. *See*, http://www.dfg.ca.gov/ospr/NRDA/Cantara.aspx.
173 *See 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.
174 *See* DEIR at 4.7.
175 DEIR at 4.7-17.
176 EPA, Comment letter to US Department of State regarding the Supplemental Draft Environmental Impact Statement from TransCanada's proposed Keystone XL project, 2013.
177 Environmental Working Group, Poisons in the Pipeline, Tests Find Toxic Stew in Oil Spill, June 2013, page 6.
178 *See* http://www.epa.gov/enbridgespill/.
179 Michigan Department of Community Health, Acute Health Impacts of the Enbridge Oil Spill, November 2010. http://www.michigan.gov/documents/mdch/enbridge_oil_spill_epi_report_with_cover_11_22_1 0_339101_7.pdf (last accessed 19 June 2013); U.S Department of Health and Human Services and ATSDR, Kalamazoo River/Enbridge Spill: Evaluation of Crude Oil Release to Talmadge Creek and Kalamazoo River on Residential Drinking Water Wells in Nearby Communities, 27 February 2013, p. 90. http://www.michigan.gov/documents/mdch/enbridge_oil_spill_epi_report_with_cover_11_22_1 0_339101_7.pdf (last accessed 20 June 2013)

(ii) The DEIR's Analysis Illegally Defers Mitigation of Public Safety Precautions.

Formulation of mitigation measures should not be deferred until some future time.[180] 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.[181] An EIR cannot rely on any management plans, studies, or reports developed after the EIR process.[182]

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.[183] This amendment and review has not yet occurred, and will not occur until after the close of the CEQA process. CEQA specifically forbids any post-project approval bilateral negotiation between project proponent and lead agency.[184] The DEIR's cursory analysis is unclear regarding whether the Spill Prevention, Control and Countermeasure Plan will also address the risk of fire or explosion and danger to the public. 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.

The DEIR also includes an exhaustive discussion of certain State regulatory bodies charged with public safety duties. The DEIR does no more than highlight the current regulatory setting, with sparse discussion of relevance to the Project. For instance, the DEIR outlines the authority delegated to the California Public Utilities Commission to inspect and maintain safety at railroad crossings, yet does not make any demonstration that Phillips 66 has or will reach out to the Commission to institute proceedings to ensure safety given a higher frequency of rail cars and traffic or "virtual pipelines" of highly flammable material passing through some of the most densely populated and environmentally sensitive (e.g., water supply for most of the state) areas in the United States.[185]

Similarly, the DEIR also notes the California Accident Release Prevention Program, which mirrors the Federal Risk Management program.[186] These programs would document hazard review, provide process hazard analyses, incident investigation, and ensures maintenance and mechanical integrity of the refinery.[187] The DEIR notes these critical requirements, however, "if applicable."[188] Its analysis has not only deferred mitigation of public safety impacts, but also pushes that mitigation beyond certainty.

The DEIR relies on plans that are not yet approved, and because it fails to provide enforceable measures and performance standards, there is no assurance the Project's impacts

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[180] CEQA Guidelines section 15126.4(a)(1)(b).
[181] *See eg.* Communities for a Better Environment v. City of Richmond, 184 Cal. App. 4th 70, 92 (2010).
[182] *Id.*
[183] DEIR at 4.4-28.
[184] *Communities for a Better Environment* v. *City of Richmond*, 184 Cal. App. 4th at 93.
[185] DEIR at 4.7-45.
[186] DEIR at 4.7-51.
[187] *Id.*
[188] *Id.*

related to hazards would not be significant and that they would be mitigated at all.[189] A revised EIR must identify all feasible mitigation measures and analyze alternatives that would substantially lessen the significant impacts of the Project.

(iii) The DEIR's Analysis of Risk of Oil Spill and Train Derailment is Innaccurate and Misleading.

In detailing the current setting of transporting crude by rail, the DEIR acknowledges the extent of dangers, for instance, the fatal accident in Lac-Mégantic, Canada.[190] The DEIR then begins its analysis of the risk of this similar Project, and either dispels those potential catastrophic incidents with either an assertion of improbability or a conclusory analysis.

An Inappropriate Threshold of Significance

First, the DEIR ignores the potentially catastrophic consequences of an accident by focusing on the alleged improbability of one occurring.[191] It finds the risk of oil spill to pose less than significant impact.

However, "a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project," constitutes a significant effect on the environment.[192] Probability does not factor into the evaluation of this adverse change alone without consideration for the magnitude of potentially catastrophic harm; the correct inquiry is whether the potential for such an adverse change exists. Regardless, the many recent incidents involving crude shipped by rail have shown that such accidents are reasonably foreseeable.

The DEIR instead incorporates a threshold of significance to measure risks to public safety that is based on probability.[193] The DEIR's analysis relies on the Santa Barbara County Public Safety Thresholds.[194] The analysis interprets the Santa Barbara thresholds to identify a significant impact based on "amber or red regions" of the Santa Barbara County Safety Criteria. These amber or red regions are determined by Fig. 4.7-5 in the DEIR. The amber or red regions are determined by comparing the number of injuries or fatalities of an activity with the frequency per year. This probability-based criteria is not compatible with CEQA. This is particularly the case for a "new" (transport of tar sands or Bakken crude) activity in a "virtual pipeline" that poses different impacts, making any historical analysis of frequency outdated and therefore irrelevant.

The DEIR commits the same error in regards to cumulative impacts: the analysis notes the proximity of the proposed Phillips pipeline (Pipeline Project) route would be located relatively close to the UPRR railroad in Price Canyon and the subsequent overlap in dangers if a derailed train/oil spill interacted with failure of the pipeline. The DEIR offers the assurance that

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[189] *See Sacramento Old City Ass'n v. City Council* (1991) 229 Cal. App. 3d 1011.
[190] DEIR at 4.7-17.
[191] DEIR at 4.7.56.
[192] CEQA Guidelines section 15382.
[193] DEIR at 4.7-55.
[194] *Id.*

the resulting "oil spill and fire," is highly unlikely, and therefore considered less than significant.[195]

Second, the DEIR further dispels any significant risks to public safety on the basis of generalized and conclusory statements that are specifically prohibited under CEQA.[196] The following are examples:

> "With the increase level of train traffic that would occur with the Rail Spur Project, there would be an increased risk of accidents at these road crossings. However, given that the trains on site would only be moving at speeds of around three miles per hour these impacts would be considered less than significant."[197]
>
> In regards to security, "the Applicant indicates that the site has a comprehensive security system designed to address all security issues. The security system is periodically tested to confirm its effectiveness. It must meet or exceed Industry standards while addressing Homeland Security issues."[198]
>
> In regards to a discussion on injury and fatality rates: "as rail traffic would occur regardless of whether additional crude oil cars were added to the train, the transportation of crude oil would not increase the accident/trauma-related injuries and fatalities associated with rail accidents.[199]
>
> "Given the properties of crude oil, the likelihood of an explosion is virtually non-existent and consequently explosion scenarios are not addressed further in this document."[200]

It is remarkable that the DEIR does not even address first response or other emergency precautions. This is particularly the case given the potential inability, as recent news has informed, of first responders to control fires from rail spills or explosions.

History of Violations

Given that this Project would implement operations to allow Phillips 66 to transport highly volatile materials up and down the West Coast through highly populated areas, Phillips 66's regulatory compliance record is highly relevant. In 2004, a leaking crude oil pipeline "caused a release" at the Santa Maria facility.[201] The DEIR, especially in the context of switching to a different quality crude slate, should have provided more information regarding

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[195] DEIR at 4.7-63.
[196] *See Berkeley Keep Jets Over the Bay Com. v. Board of Port Cmrs*. (2001) 91 Cal. App. 4th 1344, 1371 (striking down an EIR "for failing to support its many conclusory statements by scientific or objective data"); *San Joaquin Raptor Rescue Center v. County of Merced* (2007) 149 Cal. App. 4th 645, 659 ("[D]ecision makers and general public should not be forced to . . . ferret out the fundamental baseline assumptions that are being used for purposes of the environmental analysis.").
[197] DEIR at 4.7-57.
[198] DEIR at 4.7-7.
[199] DEIR at 4.7-28.
[200] DEIR at 4.7-37.
[201] DEIR at 4.7-37.

whether this incident was similar to the failed pipe in the crude unit that caused the Chevron Richmond Refinery August 6 2012 fire.

According to the U.S. Environmental Protection Agency ("EPA") the Refinery ranked as the 8th most toxic polluter of all California facilities with large chemical releases. Phillips 66 was ranked 12th on the Toxic 100 Air Polluters index.[202] This index, prepared by the Political Economy Research Institute, identifies the top U.S. air polluters among the world's largest corporations and ranks corporations based on the chronic human health risk from all of their U.S. polluting facilities.[203]

The DEIR should have provided this additional information to properly evaluate the Project. Overall, its conclusory analysis and incompatible threshold of significance violate CEQA. The DEIR failed to properly assess, or even identify, the Project's significant, perhaps even catastrophic, risks to public safety, omitting any consideration of proper and critical mitigation.[204]

D. The DEIR Fails to Adequately Analyze the Project's Impacts Related Biological Resources.

The DEIR fails to sufficiently analyze significant environmental effects on biological resources in and around the site of the Project. Specifically, the DEIR should be revised to ensure that the on-site federally-endangered Nipomo Mesa Lupine and off-site prime agricultural farmland are adequately protected.

(i) The DEIR does Not Adequately Analyze the Project's Impact on Endangered Species.

CEQA mandates a finding of significance for any impact that "restrict[s] the range of an endangered, rare or threatened species."[205] The Supreme Court applied this requirement, making clear that any impacts to federally designated critical habitat are per se significant.[206] The reasoning is manifest: the federal agency charged with the protection of a listed species has the requisite expertise to determine the habitat areas that, if impacted, would "restrict the range" of the listed species, and that determination must be respected by state and local agencies under CEQA.[207]

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[202] *See* EPA 2011 Toxics Release Inventory and the Political Economy Research Institute Toxic 100 Air Polluters, available at http://www.peri.umass.edu/toxicair_current/ (last accessed, Jan 20, 2014).
[203] The index relies on the U.S. EPA's Risk Screening Environmental Indicators ("RSEI"), which assesses the chronic human health risk from industrial toxic releases. The underlying data for RSEI is the EPA's Toxics Release Inventory ("TRI"), in which facilities across the U.S. report their releases of toxic chemicals. In addition to the amount of toxic chemicals released, RSEI also includes the degree of toxicity and population exposure.
[204] Cf: DEIR at 4.7-58.
[205] CEQA Guidelines § 15065(a)(1).
[206] *Vineyard Area Citizens for Responsible Growth, Inc., v. City of Rancho Cordova,* 40 Cal. 4th 412, 425, 449 (2007) (EIR invalidated for failure to consider significant any reduction in water flow in designated critical habitat area for the Central Valley steelhead trout).
[207] CEQA Guidelines § 15065(a)(1); see also 16 U.S.C. § 1532(5)(A)(i) (defining critical habitat as the areas "on which are found those physical or biological features essential to the conservation of the species").

Federally-and State-Endangered Nipomo Mesa Lupine

The Initial Study and DEIR identifies the Nipomo Mesa Lupine, a state and federally listed endangered plant species, as a biological resource that will be impacted through the construction and operational phases of the project. The document further identifies additional significant impacts to other ground-dwelling and animal species, including mortality impact on the American Badger, which is a fully protected species under California law, and impacts on dune shrub and dune habitats. However, the DEIR fails to mitigate the significant impacts posed to those, and other biological resources by this Project. In particular, without disclosing a switch to a different crude feedstock, the DEIR never analyzes the issues of impact or how to avoid, minimize or protect endangered species from that new feedstock and its plethora of different chemical compositions.

The Santa Maria Refinery property is home to the last remaining population of the federally-endangered Nipomo Mesa lupine.[208] Based on the botanical surveys for the DEIR, "[t]he current determination of presence/absence of Nipomo lupine within the Project Site cannot be adequately determined."[209] Though no blooming specimens were identified during the surveys, Figure 4.4-2 Sensitive Species Survey Map[210] shows two locations in the northern part of the Biological Survey Area (BSA), which according to the legend were mapped by CNPS in 2006. As represented by Figure 4.4-2, the Nipomo Mesa lupine, like many annual plants, moves around on the landscape to take advantage of preferred ecological conditions, and under drought conditions the Nipomo Mesa lupine can persist as an underground seed bank without producing above-ground individuals.[211] Consequently, despite the botanical survey's inability to detect the species, this Project will certainly directly impact previously occupied habitat, will likely indirectly impact extant habitat and populations and may impact and possibly eradicate the last remaining population of this highly endangered lupine on the planet.

To mitigate for the possibility of this impact, the DEIR proposes mitigation measure BIO-1: before project activities are undertaken, a focused survey shall be conducted during a normal rainfall season to determine whether the Nipomo Mesa lupine is present within the project site.[212] If the survey determines that the lupine is present, Phillips 66 will apply for an Incidental Take Permit with the California Department of Fish and Wildlife.[213]

The DEIR claims that, with mitigation measure BIO-5a, which involves the development of a Dune Scrub Habit Restoration Plan, the impacts on the Nipomo Mesa lupine would be less than significant.[214] However, the Dune Scrub Habitat Restoration Plan does not purport to preserve existing populations of Nipomo Mesa lupine, but instead to "restor[e] and enhanc[e] central dune scrub habitat *immediately adjacent to* known Nipomo Mesa lupine populations."[215]

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[208] USFWS letter, attached to Initial Study, Appendix C.
[209] DEIR at 4.4-17.
[210] DEIR at 4.4-16
[211] FWS letter; DEIR at 4.4-17.
[212] DEIR at 4.4-17.
[213] DEIR at 4.4-17.
[214] DEIR 4.4-17.
[215] DEIR at 4.4-22 (emphasis added).

Therefore the proposed mitigation is inadequate to fully mitigate direct and indirect impacts to the Nipomo Mesa lupine.

Additionally, if the pre-project survey does not find that the lupine is present, no mitigation is proposed to be implemented. However, 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.[216] Another survey that simply searches for blooming specimens may not prove sufficient to detect this endangered plant's populations. In any event, any of these mitigation measures, analyses or even consultation with the Fish and Wildlife Service performed *after* certification of this deficient DEIR constitutes *illegally deferred mitigation*.[217]

The DEIR should be revised to provide for the protection of this federally and state-endangered species. Further, any revisions must address the direct and indirect impacts to this species from proximity to the storage and partial refining of tar sands crude – prior to project approval. The DEIR should also be revised to consider an alternative location for construction activities in order to avoid disturbing any Nipomo Mesa lupine populations and habitat identified in future surveys.

(ii) The DEIR does Not Adequately Analyze the Project's Impacts Related to Rare Plants and Plant Communities.

The DEIR appears to downplay the status of the Silver Dune Lupine – Mock Heather Scrub Alliance which is present on the proposed project.[218] It is actually a plant alliance that is considered highly imperiled and is tracked by the California Department of Fish and Wildlife.[219]

Although the DEIR addresses the Global (G3) and State Rank (S3), it fails to describe the significance of these ranks. Global G3 rank indicates that the alliance is "moderate risk of extinction or elimination due to a restricted range, relatively few populations or occurrences, recent and widespread declines, or other factors" globally and the S3 rank indicates that it is "Vulnerable in the jurisdiction due to a restricted range, relatively few populations or occurrences, recent and widespread declines, or other factors making it vulnerable to extirpation."[220] In the case of the S3 rank, the jurisdiction is the State of California. The DEIR fails to identify the number of acres of any of the plant alliances that occur on site, including the highly imperiled Silver Dune Lupine-Mock Heather Scrub Alliance. Therefore it is impossible to evaluate the direct or indirect impacts to this rare alliance or any of the alliances from the proposed project.

(iii) The DEIR does Not Adequately Analyze the Project's Impacts Related to Wildlife.

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[216] See USFWS letter.
[217] *Communities for a Better Environment* v. *City of Richmond*, 184 Cal. App. 4th at 93.
[218] DEIR at 4.4-3
[219] *See* https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=24716&inline=1 at PDF page 50
[220] http://www.natureserve.org/publications/ConsStatusAssess_RankMethodology.pdf

The DEIR documents that American badgers occur on the proposed project site[221]. The DEIR recognizes that they are a Species of Special Concern, but it fails to recognize that they are also a fully protected species as a furbearing mammal under California Code of Regulations Title 14 Section 460. By simply excluding badgers from their dens, as proposed in Bio-4, does not answer the question if that exclusion results in "take" of the badger or not. Additional monitoring of the displaced badger(s) is(are) required.

In addition, the DEIR documents that burrowing owls occur on the proposed project site.[222] The DEIR recognizes that burrowing owls are Species of Special Concern, but it fails to identify any avoidance or mitigation strategy for the owls. Burrowing owls are in decline throughout California, and as the DEIR recognizes has not reproduced successfully in the central coast in the last 20 years. However, that does not eliminate the need to provide mitigation habitat for the owls that will be impacted by the proposed project. The DEIR needs to comply with the California Department of Fish and Wildlife's recent guidance on burrowing owl,[223] which requires projects to:

> "Mitigate for permanent impacts to nesting, occupied and satellite burrows and burrowing owl habitat with
>
> (a) permanent conservation of similar vegetation communities (grassland, scrublands, desert, urban, and agriculture) to provide for burrowing owl nesting, foraging, wintering, and dispersal (i.e., during breeding and non-breeding seasons) comparable to or better than that of the impact area, and
> (b) sufficiently large acreage, and presence of fossorial mammals." (at 12).

Other requirements for mitigation are also included in the California Department of Fish and Wildlife's guidance, requirements omitted from the DEIR's analysis.

(iv) The DEIR does Not Adequately Analyze the Project's Impacts Related to Agricultural Activities.

The DEIR fails to include a comprehensive analysis of agricultural site constraints. Without a full investigation, the DEIR has no basis to conclude that the proposed construction of Project components in an agricultural area would not result in impacts. Site constraints, such as the presence of livestock, and the potential impact of diesel exhaust on pasture and cattle, must be identified prior to Project approval. An EIR must include objective measurements of a cumulative impact when such data are available (or can be produced by further study) and are necessary to ensure disclosure of the impact.[224]

San Luis Obispo County is one of the leading agricultural production counties in California.[225] The site of the Proposed Project borders prime farmlands on its southern border,[226]

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[221] DEIR at 4.4-20
[222] DEIR at 4.4-29
[223] http://www.dfg.ca.gov/wildlife/nongame/docs/BUOWStaffReport.pdf
[224] *See Kings County Farm Bureau*, 221 Cal. App. 3d at 729.
[225] DEIR at 4.2-1.

and a portion of the project site currently supports grazing activities.[227] Despite this, the DEIR asserts that the construction of a rail spur and the travel of up to 250 unit trains, each with 73 to 80 tank cars each year would have no significant and unavoidable impacts to agricultural resources.

The DEIR acknowledges that construction and operations activities could result in significant impacts on the productivity of adjacent farmlands—dust and contaminated air emissions, hazardous materials spills, and increased water use, among other impacts, could adversely affect agricultural lands adjacent to the project site by contaminated soil and water and putting strain on already limited water resources.[228] Further, the DEIR, by cross-referencing to other mitigation measures, including oil spill control and fugitive dust monitoring, asserts that the impacts on adjacent agricultural lands could be mitigated to less than significant.[229] This conclusory assessment is insufficient. Agricultural impacts are considered significant if they impair the agricultural use of other property.[230] The DEIR's "bundled" mitigation measures do not provide substantial evidence that the Project will not significantly impact adjacent agricultural properties.

E. The Project is Inconsistent with State and Local Plans.

An EIR shall discuss any inconsistencies between the proposed project and applicable general plans, specific plans and regional plans.[231] Such regional plans include, but are not limited to, the applicable air quality attainment or maintenance plan or State Implementation Plan, area-wide waste treatment and water quality control plans, regional transportation plans, regional housing allocation plans, regional blueprint plans, plans for the reduction of greenhouse gas emissions, habitat conservation plans, natural community conservation plans and regional land use plans for the protection of the coastal zone.[232] An applicable plan, policy, or regulation is one that has already been adopted and thus legally applies to a project.[233] This necessarily includes County General Plans, such as the SLO County General Plan, adopted by the County in 2010, and other applicable State and Federal regulations, executive orders and policies.

The DEIR fails to discuss any potential inconsistency with applicable plans, polices, and regulations including (1) the San Luis Obispo County General Plan, (2) Contra Costa County's Industrial Safety Ordinance, and General Plan, (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

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[226] DEIR at 4.2-15, Figure 4.2-3.
[227] DEIR at 4.2-2.
[228] DEIR at 4.2-22.
[229] DEIR at 4.2-22.
[230] DEIR at 4.2-19.
[231] CEQA Guidelines § 15125(d).
[232] *See, San Franciscans Upholding the Downtown Plan v. City & Cnty. of San Francisco* (2002) 102 Cal.App.4th 656, 678.
[233] *Chaparral Greens v. City of Chula Vista* (1996) 50 CA4th 1134, 1145, n7.

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.[234] The Project, however, will increase all of those issues, wholly conflicting with the General Plan's over-arching environmental goals.

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.[235] Phillips 66's switch to denser, higher sulfur crude, as well as its storage, transport and the process for recovery of propane and butane at the Rodeo facility, as a result of this Project conflicts with the Contra Costa County Industrial Safety Ordinance that requires Inherently Safer Systems. The pending project proposals at both facilities are also inconsistent with the recommendations of the Chemical Safety Board ("CSB").

In particular, the CSB found a catastrophic and hazardous failure from running higher sulfur crude in existing refineries built before 1985.[236] The CSB identified that corrosion at the Chevron Richmond Refinery, which led to the pipe rupture, was in large part caused by sulfur compounds in the crude processed at the Richmond refinery.[237] It 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.[238] The DEIR fails to recognize the CSB's analysis and fails to address any proposed recommendations made by the CSB. Thus, it is unclear whether there would be a potential conflict between what the Project entails and what the CSB has set forth as its recommendations for refinery safety. What appears clear, is that the types of crude that the Refinery will be importing by rail will dramatically increase the overall sulfur content in the Refinery's crude slate, and would thus likely cause similar issues to those experienced at the Chevron Refinery, which lead to the Chevron Refinery fire, in August, 2012.[239]

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.

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[234] 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.
[235] *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.
[236] *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, last accessed, Jan. 26, 2014.
[237] *Id.*
[238] *Id.*, at 15.
[239] *See*, Chemical Safety Board, Chevron Richmond Refinery Interim Investigation Report, April 2013, *supra*.

The DEIR does little more than simply mention OSHA, and provides cursory statements in section 4.3, relating to Air Quality Impacts, and elsewhere, that diminish the relevance of the Act. For example, without stating a current or anticipated, foreseeable increase in the presence of hydrogen sulfide, the DEIR states that the hydrogen sulfide levels within the crude slate are "not expected to produce substantial impacts beyond possible OSHA related worker exposure issues…"[240] The DEIR even claims that such issues are outside the scope of the EIR.[241] In section 4.7, in the context of Hazards assessment, the DEIR states only that the Project's security vulnerability assessments must comply with OSHA Process Safety Management and EPA rules relating to risk management. The DEIR fails to acknowledge, however, that such issues must be raised, and included in a potential conflicts analysis, as the components and implications of the Project may conflict with such rules, given the potential hazards and dangerous impacts the Project may have on workers.

The President's August, 2013 EO, was signed and executed for the purpose of creating a comprehensive plan to address increasing chemical safety concerns throughout various industrial facilities, including refineries.[242] To that end, the President ordered a federal working group that includes, *inter alia*, OSHA and the EPA, to begin the process of improving operational coordination with State and Local partners, as well as owners and operators of industrial facilities increasing their use of hazardous chemicals. By simply dismissing, or failing to adequately analyze the increase in safety and hazards impacts that will result from the Project, the DEIR fails to demonstrate compliance with new federal initiatives such as the EO and forthcoming recommendations which will result from CSB's investigations. The DEIR, therefore, fails to sufficiently address potential conflicts with existing laws, rules, or regulations, in violation of CEQA.[243]

Finally, although the DEIR mentions the Global Warming Solutions Act of 2006 (AB 32) in its list of applicable regulations in the documents "Regulatory Setting" section, the DEIR's analysis fails to fully recognize that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." The DEIR further fails to actually identify, much less analyze the project's true GHG emission levels, in the context of the current state-wide 2020 greenhouse gas emissions reduction goals, which are, pursuant to AB 32, signed into law. The DEIR's omission of an adequate GHG analysis, stands in stark contrast to statements made by Phillips 66 officials themselves, relating to the possible conflict between the law and their strategy for their two California refiners. Asked what he thought the permitting track is for delivering Bakken crude or Canadian heavy crude to California by rail, CEO Garland replied, "I think we are pushing it. I think there is some resistance, given the heavy nature of the crudes and the carbon footprint of the crudes and AB 32

[240] DEIR, 4.3-52.
[241] *Id*.
[242] *See* Executive Order Improving Chemical Safety and Security, August 1, 2013, available at: http://www.whitehouse.gov/the-press-office/2013/08/01/executive-order-improving-chemical-facility-safety-and-security.
[243] *See generally*, Guidelines § 15125(d); *see also*, *Chaparral Greens v. City of Chula Vista* (1996) 50 CA4th 1134, 1145.

cap and trade, et cetera, et cetara [sic] in California."[244]

The DEIR fails to address the above examples of the Project's conflicts with local, State and Federal plans. Overall, the DEIR's description of the Project and its environmental setting is inaccurate and inadequate to the extent that it improperly minimizes the environmental effects discussed further throughout this comment.

III. THE EIR FAILS TO ADEQUATELY ANALYZE THE PROJECT'S CUMULATIVE ENVIRONMENTAL IMPACTS FROM OTHER REFINING-RELATED PROJECTS.

An EIR must discuss a Project's significant cumulative impacts.[245] 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."[246]

A project has a significant cumulative effect if it has an impact that is individually limited but "cumulatively considerable."[247] "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."[248] 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."[249] The DEIR fails to meet this requirement; for the following reasons, its analysis of cumulative impacts is incomplete, cursory and superficial.

Initially, the DEIR's analysis does not comply with CEQA's requirement that agencies first determine whether cumulative impacts to a resource are significant, and then to determine whether a project's impacts are cumulatively considerable (*i.e.,* significant when considered in conjunction with other past, present and reasonably foreseeable projects).[250] The DEIR skips the first step and focuses only on the second.[251] This error caused the document to underestimate the significance of the Project's cumulative impacts because it focused on the significance of the Project's impacts on their own as opposed to considering them in the context of the cumulative problem. It is wholly inappropriate to end a cumulative analysis on account of a determination that a project's individual contribution would be less than significant. Rather, this should constitute the beginning of the analysis.

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[244] *Transcript of Jan. 30, 2013 Phillips 66 Fourth-Quarter Earnings Conference Call*, available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/PSX-Transcript-2013-01-30T.pdf, last accessed Jan. 26, 2014, 2013.
[245] CEQA Guidelines section 15130(a).
[246] CEQA Guidelines section 15355(b).
[247] *Id*. §§ 15065(a)(3), 15130(a).
[248] *Id*. § 15065(a)(3).
[249] *Communities for a Better Env't v. Cal. Res. Agency* (2002) 103 Cal.App.4th 98, 114.
[250] CEQA Guidelines § 15064(h)(1).
[251] *See eg*. DEIR at 4.7-61.

Second, the DEIR's scope is limited largely to direct, immediate impacts within the immediate Project vicinity. For example, the analysis of cumulative hazards of transporting crude by rail, the analysis of impacts is limited to the County, despite the fact that Project-related rail traffic would pose the same risks throughout its California wide route.

Third, the list of reasonably foreseeable future projects considered in the EIR is under inclusive, especially in light of the potential geographic scope of certain potentially significant impacts. One of the EIR's most egregious deficiencies is the document's failure to disclose that several California refiners are considering developing "Crude By Rail" projects that could bring in tar sands-based dilbit or Bakken crudes to each of the Bay Area refineries.[252] Each of the Bay Area's refineries have either recently permitted projects or have pending permits that will facilitate transporting and refining tar sands crude. These refinery projects, including at least three projects proposed by Phillips 66 (Santa Maria Facility Throughput Extension Project, this Project, and the Ferndale Washington Crude Unloading Facility Project), as well as several others including the Valero Crude by Rail Project, the Tesoro Project, and the WesPac Pittsburg Energy Infrastructure Project could result in the delivery of tar sands diluted with other chemicals to the Bay Area.

The California Attorney General has even expressed concern, and recently wrote the attached letter to the City of Pittsburg[253], inquiring about the link of the WesPac project to other refineries in the Bay Area. This County should also ask the same relevant questions.

Although the DEIR mentions these Santa Maria projects, and purports to analyze the cumulative environmental impacts from the projects it identifies (it uses the wrong baseline, the permit levels), it does not come close to disclosing the full list of projects with staggering environmental impacts on the Bay Area.[254]

Three other projects omitted from consideration in the DEIR's analysis of cumulative environmental impacts include[255]:

(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 DEIR 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 DEIR fails to evaluate the Project's cumulative

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[252] *See* Karras and Fox Rodeo Reports.
[253] See Letter from Attorney General, Kamala D. Harris, to City of Pittsburg, *Recirculated Environmental Impact Report for the WesPac Energy Infrastructure Project*, dated January 15, 2014, attached as Exhibit 25.
[254] *See* DEIR Table 3.1.
[255] 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.

impacts of Santa Maria semi-refined products in, and in transport to, Rodeo. These include a cumulatively considerable increase in criteria and toxic air contaminant air emissions and greenhouse gas emissions. This includes cumulative environmental impacts of refining increased volumes of tar sands crude.

(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.[256]

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.[257]

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.[258] 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 BBLs per day.[259] 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.[260]

As mentioned above, the Phillips San Francisco Refinery is one of the refineries that may receive crude oil and/or deliver-crude oil to the Terminal.[261] Therefore, the DEIR should have included an analysis of this WesPac project in the cumulative impact analysis, both because the physical construction and operation of this facility will contribute to cumulative environmental impacts and because it could facilitate greater amounts of crude delivery to and from the Santa Maria facility. The DEIR 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 DEIR must identify feasible mitigation measures capable of reducing these environmental impacts.

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[256] WesPac RDEIR at 2.0-1.
[257] *Id*. at 2.0-4.
[258] *Id*. at 2.0-1.
[259] *Id*. at 2.0-2.
[260] *Id*.
[261] *Id*.

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.[262] 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."[263]

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 DEIR should have acknowledged the switch to this different quality crude oil feedstock and provided a suitable cumulative impacts analysis.

IV. THE DEIR FAILS TO ANALYZE A REASONABLE RANGE OF PROJECT ALTERNATIVES

An EIR "must consider a reasonable range of potentially feasible alternatives" to a project.[264] An alternative is feasible 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."[265]

Although "CEQA establishes no categorical legal imperative as to the scope of alternatives to be analyzed in an EIR[,] [e]ach case must be evaluated on its facts."[266] The scope of alternatives is judged by the rule of reason.[267] Generally, the scope of alternatives is sufficient so long as the EIR provides "information sufficient to permit a reasonable choice of alternatives

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[262] *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.").
[263] *Communities for Better Env't v. Cal. Res. Agency* (2002) 103 Cal. App. 4th 98, 120.
[264] 14 Cal. Code Reg. § 15126.6(a).
[265] Cal. Pub. Res. Code § 21061.1.
[266] *Citizens of Goleta Valley v. Bd. of Supervisors* (1990) 52 Cal. 3d 553, 556 (*Goleta II*).
[267] 14 Cal. Code Reg. § 15126.6(a) ("There is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason.").

so far as environmental aspects are concerned."[268] In addition, the EIR must include "sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project."[269] "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.'"[270] Thus, an EIR for a specific project must necessarily be more detailed than an EIR for the approval of a general plan.[271]

The DEIR fails to identify a reasonable range of alternatives and to discuss the alternatives in sufficient detail to allow meaningful evaluation and analysis.[272] The DEIR analyzed only three alternatives: a no project alternative, a loop rail unloading configuration alternative, and a reduced rail deliveries alternative.[273] The DEIR also identified four 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 included two trucking alternatives, a marine transport alternative, and a rail unloading at the Santa Maria Pumping Station alternative.[274]

(a) The DEIR Fails to Consider a Reasonable Range of Alternatives.

The DEIR, however, fails to consider even the most simple of alternatives, for example, an alternative rail route that avoids the populations with the highest density in Central and Northern California. Currently, the Rail Spur Project proposes a rail route that would bring trains of crude oil through heavily populated urban areas, exposing large numbers of people to the criteria air emissions associated with locomotive operation, and greatly increasing the human health and safety risks of potential accidents or spills. A spill in the Sacramento-San Joaquin Delta, for example, could jeopardize the water supply for much of the State. Instead of directing trains through Northern California, along the Sacramento River and through the City of Oakland, the DEIR should analyze an alternate rail route that would avoid bringing rails cars containing highly flammable and volatile crude or semi-refined gas oil through high population areas.

The DEIR should also be revised to include an analysis of alternative modes of transporting crude oil from oilfields across North America. For example, the DEIR analyzed only one marine transport alternative, and did not analyze a pipeline alternative. Parties objecting to the EIR are not responsible for formulating alternatives for consideration—the lead agency bears this burden.[275] 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.[276] The DEIR failed to include these two, and other reasonable alternatives in its analysis.

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[268] *Found. for San Francisco's Architectural Heritage v. San Francisco* (1980) 106 Cal. App. 3d. 893, 910.
[269] 14 Cal. Code Reg. § 15126.6(d).
[270] *Al Larson Boat Shop, Inc. v. Bd. of Harbor Commrs.* (2d Dist. 1993) 18 Cal. App. 4th 729, 746 (quoting 14 Cal. Code Reg. § 15146).
[271] *See Al Larson Boat Shop, Inc. v. Bd. of Harbor Commrs.* (2d Dist. 1993) 18 Cal. App. 4th 729, 746.
[272] *See* 14 Cal. Code Reg. § 15126.6(d).
[273] DEIR at 5-24.
[274] DEIR at 5-15 to 5-23, Tables 5.1 and 5.2.
[275] *See Laurel Heights I*, 47 Cal. 3d at 406.
[276] *See Laurel Heights I*, 47 Cal. 3d at 406.

(b) The DEIR Fails to Consider Alternatives that Would Lessen the Significant Impacts of the Project.

In addition to failing to assess a reasonable range of alternatives, the DEIR fails to analyze alternatives that would avoid or substantially lessen the significant impacts of the project.[277] Of the three alternatives analyzed, the DEIR identifies the no project alternative as the environmentally superior alternative.

However, when the no project alternative is the environmentally superior alternative, CEQA requires an EIR to identify the next environmentally superior alternative. The DEIR identifies the reduced rail deliveries alternative as the next environmentally superior alternative, but notes that certain environmental impacts of the reduced rail deliveries alternative depend heavily upon the question of whether the County would be preempted by federal law from regulating locomotive emissions outside of the Santa Maria Refinery site.[278] As discussed above, the argument that the County may be preempted from regulating air impacts outside of the project site is invalid. Consequently, according to the County itself, the reduced rail deliveries alternative would offer no advantage over the Proposed Project in terms of NO_x, ROG, and diesel particulate emissions, and only a minimal advantage in terms of hazard risks, noise, GHG emissions, and health risks.[279] Even assuming *arguendo* that preemption applies, the reduced rail deliveries alternative, while better than the proposed Project, still has significant impacts.

The DEIR's failure to consider even an alternative with more than minimal environmental advantages over the proposed project is contrary to the purpose of the CEQA alternatives requirement. An EIR must identify a range of reasonable alternatives "which would feasibly attain most of the basic objectives of the project *but would avoid or substantially lessen any of the significant effects of the project*."[280] None of the alternatives considered in the DEIR, including the reduced rail deliveries alternative, would avoid or substantially lessen the significant impacts of the Project; the range of alternatives considered in the DEIR is insufficient.

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[277] See CEQA Guidelines, 14 Cal. Code Reg. § 15126(a).
[278] DEIR at 5-35 to 5-36.

[280] 14 Cal. Code Reg. § 15126.6(a) (emphasis added).

V. CONCLUSION

The DEIR remains woefully inadequate under CEQA. The County must substantially revise and recirculate the document in order to correct its numerous defects. We appreciate the opportunity to submit our initial comments on the DEIR and will submit further comments, if necessary, as soon as possible.

Sincerely,

/s/

Roger Lin
Greg Karras
Yana Garcia
Heather Lewis
On behalf of Communities for a Better Environment

Devorah Ancel
Staff Attorney
On behalf of the Sierra Club

Diane Bailey
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On behalf of San Francisco Baykeeper

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On behalf of California Nurses Association

Comments

on

Environmental Impact Report

for the

Phillips 66
Rail Spur Extension Project

Santa Maria, California

Prepared
for
Sierra Club
San Francisco, CA

January 27, 2014

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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 crude oil, to replace local supplies. The proposed tracks and unloading facilities would be designed to accommodate unit trains of up to 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 the Sierra Club to review the Draft Environmental Impact Report (DEIR)[1] on this Project and prepare comments on the adequacy of the project description and the hazards and hazardous materials section.

My evaluation, presented below, indicates the DEIR's Project description is incomplete. First, it fails to disclose the baseline crude slate composition, which determines the CEQA baseline emissions from crude import through refining. Second, it fails to disclose the link between the Rail Spur Project and two other directly related projects: (1) the Propane Recovery Project at Phillips 66's Rodeo facility,[2] which is linked by pipeline to the Rodeo Refinery, and (2) the Throughput Increase Project at the Santa Maria Refinery[3]. The impacts of these directly related projects should be evaluated as a single project. Together, they result in many significant impacts that were not disclosed in the Rail Spur Project DEIR.

The DEIR fails to evaluate the impacts resulting from a significant switch in crude slate, the raison d'etre for the Project. The entire Project, including crude slate change, would result in significant unmitigated air quality, global warming, worker and public health, odor, risk of upset, public safety, visual, noise, and other impacts, either not disclosed or not mitigated in the DEIR. Finally, the DEIR fails to evaluate reasonable alternatives to the Project and to impose all feasible mitigation.

My resume is included in Attachment 1 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 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

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[1] Marine Research Specialists (MRS), Phillips 66 Company Rail Spur Extension Project Public Draft Environmental Impact Report and Vertical Coastal Access Assessment, November 2013.

[2] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project, Final Environmental Impact Report, November 2013 (FEIR).

[3] 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.

professional engineer (chemical, environmental) in five states, including California; a Board Certified Environmental Engineer, certified in Air Pollution Control by the American Academy of Environmental Engineers; and a Qualified Environmental Professional, certified by the Institute of Professional Environmental Practice.

I have prepared comments, responses to comments and sections of EIRs for both proponents and opponents of projects on air quality, water supply, water quality, hazardous waste, public health, risk assessment, worker health and safety, odor, risk of upset, noise, land use and other areas for well over 100 CEQA documents. 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 DEIR only evaluated a portion of the Project. The Project as described in the DEIR is narrowly defined as a modification to an existing rail spur extension to allow crude to be delivered to the Santa Maria Refinery by train for processing. DEIR, p. 2-1. However, as explained below, the Rail Spur Project is actually only one of the components of a much larger project consisting of at least three parts: (1) Throughput Increase Project; (2) Rail Spur Project; and (3) Propane Recovery Project at Rodeo.

The Santa Maria Refinery currently receives all crude oil by pipeline from various mostly local sources, including the Outer Continental Shelf (60-85%), Price Canyon/Santa Maria Valley/San Joaquin Valley (5-20%), San Ardo (5-10%), and Canada (2-7%). DEIR, p. 2-27. Most all of these sources, particularly the major ones -- offshore platforms and local oil fields -- are in decline. DEIR, p. ES-18 ("However, if and when local crude oil production (the major source of oil for the SMR) declines, the Rail Spur Project...would allow the SMR to maintain operating up to its permitted throughput levels."), p. 2-30 ("In addition, production from offshore Santa Barbara County [the major source of SMR's crude] has been in decline for a number of years... This declining production... generates the need for the Rail Spur Project."), p. 6-3 ("California production of crude oil per year has been in decline since 1986...The decline has average about 1.7% per year since 1995. More recently, the decline has averaged over 3% annually since the year 2000... Delivery of other North American crudes to California could help to offset the need for foreign imports as local production declines.") Thus, the

Throughput Project likely could not be implemented but for the Rail Spur Project, which allows crudes to be imported to replace declining local sources.

A. Link With Crude Throughput Increase Project

Thus, Phillips 66 is arguing on the one hand that the Rail Spur Project is required to replace dwindling local crude supplies while on the other it has proposed to increase its throughput capacity, without disclosing the source of the new crude. Clearly, Phillips 66 anticipated the need to increase its crude supply, given the diminishing local supplies, when it was planning the Crude Throughput Increase Project in 2008,[4] at a time it faced dwindling local crude supplies at high costs. Thus, the need to import more cost-effective crudes from distant sources, accessible only by rail, must have been on the table at the time the Throughput Increase Project was developed.

The decline in local crude supplies is not news and has long been known.[5] In fact, given the admitted declining local sources of crude, it is not believable that the SMR could increase its throughput by 10%, when a 3% annual decline in its major source of oil is projected, without changing its source of crude. This is prima facie evidence that the Throughput Increase Project and the Rail Spur project are related and were likely planned together. Thus, one of the key purposes of the Rail Spur Project is to build the infrastructure to allow crude oil to be imported from distant sources to replace declining local crude oil sources and facilitate a 10% increase in crude throughput, separately permitted.

The average baseline crude throughput for Santa Maria (2010-2012) is 38,029 barrels per day (BPD). DEIR Table 2.7. The Throughput Increase Project increased the permit level from 44,500 BPD (Throughput FEIR, p. ES-4) by 10% to a maximum of 48,950 BPD or by 4,450 BPD. Throughput FEIR, p. 1-1. Thus, the SMR was operating at 6,471 BPD below the CEQA baseline for the Rail Spur Project and 10,921 BPD below the projected future daily maximum throughput. It is unlikely that the permitted crude throughput of 48,950 BPD (DEIR, p. 2-28) could be supplied locally, given the decline in locally available crudes.

Thus, the Rail Spur Project is required to achieve the increase in throughput. The Rail Spur Project essentially opens up new markets for the Santa Maria Refinery, allowing it to replace declining local sources, supply the 10% permitted throughput increase, and compete with any increase in locally produced crudes. This ties the Rail Spur Project directly to the Throughput Increase Project. Thus, these two projects are different sides of the same coin and should have been evaluated as a single project.

The Rail Spur Project will allow an increase in crude processing of up to 10,921 BPD. The DEIR did not, but must, analyze all of the impacts of this increase in

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[4] The DEIR was issued August 2011, Available at: http://www.slocleanair.org/COP3.php.

[5] California Energy Commission, Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report, May 2010.

crude throughput processing capacity, including the increase in emission of processing an additional 10,921 BPD of crude and the increase in emissions of a change in the crude slate itself. The DEIR analyzes none of the impacts associated with a 10,921 BPD increase in crude throughput or the change in crude slate.

B. Link With Propane Recovery Project at Rodeo

Both of these Santa Maria projects are directly related to a third project at Phillips 66's San Francisco Refinery, located in Rodeo in the San Francisco Bay Area. The Rodeo Refinery and the Santa Maria Refinery are connected by a 200-mile pipeline, used to transport semirefined products from Santa Maria to Rodeo for finishing into market products. DEIR, p. 2-3. These two locations, although more than 200 miles apart, are considered one location.[6] The Phillips 66 website similarly describes these facilities thus: "The San Francisco Refinery is comprised of two facilities linked by a 200-mile pipeline. The Santa Maria facility is located in Arroyo Grande, Calif., while the Rodeo facility is in the San Francisco Bay Area."[7]

The two facilities operate in unison, the Santa Maria Refinery supplying feedstocks, naphtha and gas oil, to Rodeo via pipeline to be upgraded into finished petroleum products, such as gasoline and jet fuel. DEIR, p. 2-3. Thus, these two refineries are inextricably linked. Changes in operations at one of them manifest as changes in the other. A change in crude slate at Santa Maria, for example, will manifest as changes in emissions from refining the resulting semi-refined products at Rodeo.

The Rodeo Refinery is proposing to recover an additional 4,200 barrels per day (BPD) of propane and 3,800 BPD of butane from the refinery fuel gas (RFG) (collectively known as "liquefied petroleum gas" or LPG) to export for sale (Project).[8] My review of the FEIR for that project indicates that the Rodeo Refinery as operated in the baseline would be unable to recover this amount of LPG without increases in the amount of propane- and butane-containing feed to the affected units. Fox Report[9], Comment II.

The partially refined products from the increase in crude throughput at Santa Maria will be sent to the Rodeo Refinery for further processing. As explained below, these partially refined products include significant amounts of propane and butane that will be recovered at Rodeo under the Propane Recovery Project to meet its design LPG recovery goal. Thus, cumulative impacts of these three projects -- crude throughput

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[6] BAAQMD, Review of Current Air Monitoring Capabilities near Refineries in the San Francisco Bay Area, July 3, 2013; p. 1-5, Available at: http://www.baaqmd.gov/~/media/Files/Technical%20Services/DRI_Final_Report_061113.ashx.

[7] http://www.phillips66.com/EN/about/our-businesses/refining-marketing/refining/Pages/index.aspx.

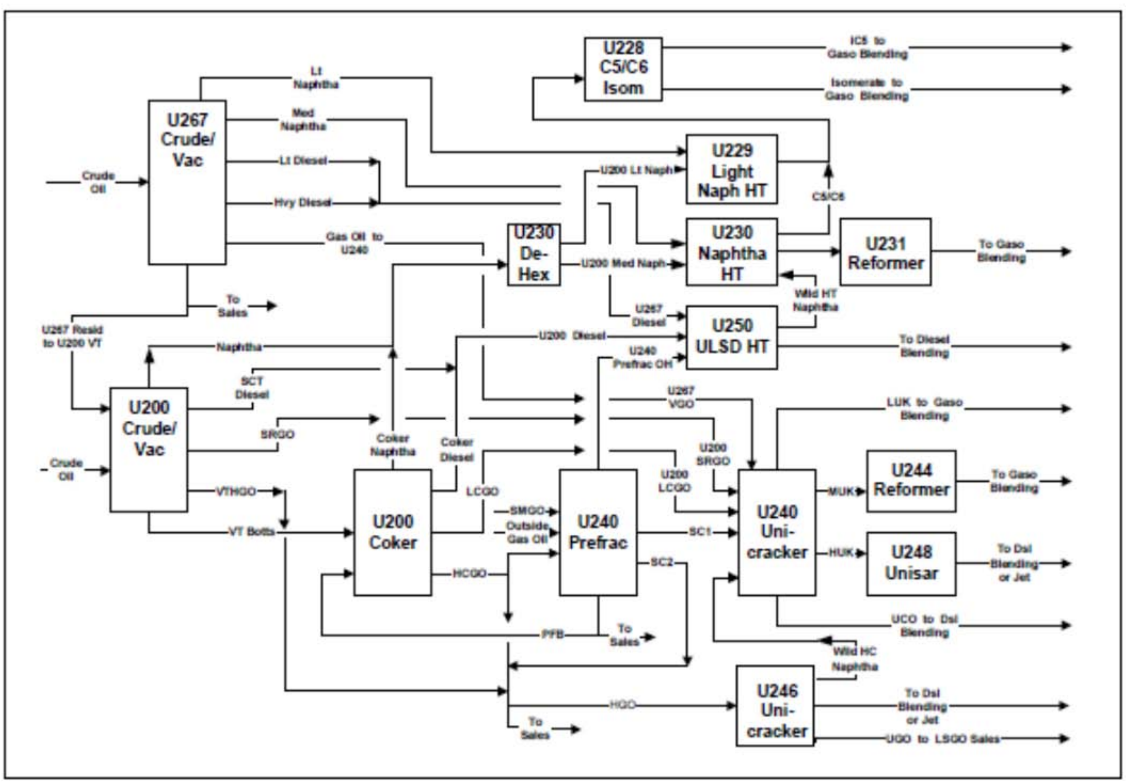
[8] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project, Final Environmental Impact Report, November 2013 (FEIR).

[9] *See* Fox Rodeo Report, Comment II.

increase + rail spur to supply the increased crude + project to recover propane/butane from the increased throughput -- should have been evaluated as a single project.

The link between the Santa Maria Refinery semi-refined products (gas oil, naptha) and the Rodeo Propane Recovery Project is clearly shown in the Rodeo Refinery block flow diagrams from the Rodeo Propane Recovery DEIR. The block flow diagram for the existing Rodeo Refinery (Rodeo DEIR Figure 3-4) shows "SMGO" entering the Refinery at the U-240 Prefractionator unit (Prefrac unit). See Rodeo DEIR, p. 3-12 ("Heavy gas oil (HGO) streams from Unit 200 and HGO purchased from outside of the Refinery are fractionated in the Unit 240 prefractionator.") SMGO is Santa Maria Gas Oil. This Rodeo DEIR figure is reproduced here as Figure 1 for ease of reference. The U-240 Prefrac unit at Rodeo separates Santa Maria gas oil and other gas oils into lighter hydrocarbon fractions that are currently blended into the Rodeo Refinery Fuel Gas, shown in Rodeo DEIR Figure 3-5 (see lower left hand corner, blue arrow labeled U-240/244/248 S-RFG being routed to U-240 Fuel Gas Treating), but which will be further processed into propane and butane in new units added to the Rodeo Refinery as part of the Propane Recovery Project.

Figure 1
Overall Existing Rodeo Refinery
Block Flow Diagram

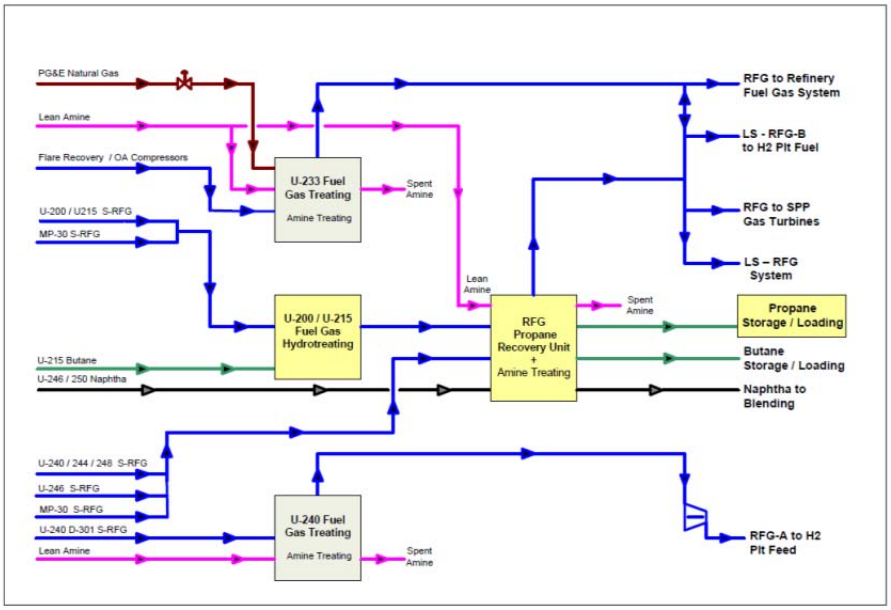


SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-4
Overall Block Flow Diagram of Refinery

Under the Propane Recovery Project at Rodeo, the output from the Prefrac unit is sent to the proposed "RFG Propane Recovery Unit" instead of the Refinery Fuel Gas system. This unit is the heart of the Propane Recovery Project. Rodeo DEIR, Table 3-2. Propane and butane are recovered in this unit. This new propane/butane extraction unit is shown in Propane Recovery Project DEIR in Figure 3-6, which is reproduced here as Figure 2 for ease of reference.

Figure 2
Proposed Rodeo Refinery
Fuel Gas System Block Flow Diagram



SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-6
Proposed Refinery Fuel Gas System Block Flow Diagram

The RFG Propane Recovery Unit is the big yellow box in the middle of Figure 2. Blue arrows in the lower left hand corner of Figure 2 identify the inputs to this unit, which are various refinery streams. These streams include "U-240/244/248 S-RFG." This designation means that Refinery Fuel Gas (RFG) from Unit U-240 is sent to the RFG Propane Recovery Unit. (This stream was formerly sent to the U-240 Fuel Gas Treating Unit. Rodeo DEIR, Fig. 3-6.) As Santa Maria Gas Oil (SMGO) is one of the inputs to Unit U-240, changes at the Santa Maria Refinery would be transmitted directly to the Propane Recovery Project via the U-240 Prefrac Unit at Rodeo.

This establishes a direct link between the Rodeo Propane Recovery Project and the two modifications at the Santa Maria Refinery -- the Throughput Increase Project and the Rail Spur Project to supply the increase in crude. This is the "nexus" to the larger project with the potential to change crude oil feedstocks.

The increase in throughput at the Santa Maria Refinery would increase the amount of SMGO and naphtha processed at Rodeo into propane and butane. As discussed elsewhere in these comments, the new rail spur at the Santa Maria Refinery would enable tar sands and other crudes to be imported to and processed at Santa Maria. Tar sands crudes imported by rail are blended with a diluent that is rich in butane and propane. Other potential imports, including Bakken crudes, also are rich in propane and butane feedstocks required at Rodeo. Thus, both projects proposed for the Santa Maria Refinery will have a direct impact on the amount of propane and butane available for recovery at Rodeo, making up for the deficit in the propane and butane in Rodeo refinery fuel gas for LPG recovery.

Thus, there is both a direct pipeline link between the two facilities, an explicit statement that the Santa Maria Throughput Increase Project was developed to send more semi-refined product to the Rodeo Refinery, a pipeline linking the two facilities, and a direct process link between those products and the input to the Propane Recovery Project disclosed on the process flow diagrams. These factors establish a nexus between the Santa Maria Rail Spur and Throughput Increase Projects and the Propane Recovery Project at Rodeo. Thus, these projects are integrally related and should be evaluated as a single project under CEQA.

III. THE PROJECT WOULD REPLACE THE EXISTING CRUDE SLATE WITH CHEMICALLY DISTINCT CRUDES

The DEIR strongly hints that the Project would import Bakken crudes, noting the Rail Spur Project would import crude oil "sourced from oilfields throughout North America based on market economics and other factors. The most likely sources would be the Bakken field in North Dakota or Canada." DEIR, p. ES-3. Elsewhere, the DEIR indicates: "These could include fields as far away as the Bakken field in North Dakota or Canada." DEIR, p. 2-21. See also: "The most likely sources of crude oil for the SMR would be North Dakota, Canadian, and Mid Continent area." DEIR, p. 4.12-21. This crude is chemically distinct from the existing crude slate. Further, as discussed below, the Rail Spur Project is also designed to import Canadian tar sands crudes. These tar sands crudes are also chemically distinct from the baseline crude slate. These differences in crude slate composition will result in significant impacts that were not disclosed in the DEIR.

A. Bakken Crudes As Feedstock for the Santa Maria Refinery

The Project description suggests that Bakken crudes would be imported by rail. While we believe this is unlikely for the reasons outlined below, the DEIR must nevertheless, given its assertions, evaluate the impact of refining this crude, which is chemically distinct from the current crude slate and from tar sands.

A refiner's choice of crude oil is influenced by the specific collection of processing units at the refinery and their design. Refinery configurations are unique and are typically designed to process a specific crude slate. The challenge for a refinery, then, is finding the cheapest crude that is compatible with the refinery's design.

The Santa Maria Refinery is designed to refine heavy, high sulfur crudes, such as those available locally with a general composition as summarized in Table 1, below. DEIR, p. 2-3.

Table 1
Properties of Crude Oil Currently Refined at Santa Maria (DEIR, Table 2.6).

Characteristic	Value
Gravity, API	19
Specific Gravity at 60 degrees Fahrenheit	0.9377
Hydrogen Sulfide Concentration	< 1 parts per million by weight
Sulfur content	4.6 % by weight
Light ends (propane thru Hexanes)	Approximately 6 %
Vapor Pressure (dry equivalent, DVPE)	6.95 pounds per square inch
Kinematic Viscosity at 104 degrees Fahrenheit	245 centistokes

The Santa Maria Refinery consists of atmospheric pressure distillation, vacuum distillation, delayed coking, and sulfur recovery, designed specifically to breakdown these local heavy high sulfur crudes into semirefined products. The semi-refined products -- gas oil and naphtha -- require additional refining at Rodeo to convert them into gasoline and other finished products. DEIR, Sec. 2.0. Thus, major changes in the crude slate at Santa Maria would necessarily result in major design changes at both the Santa Maria and Rodeo Refineries. More naphtha, especially lighter napthas, and less gas oil would be produced at Santa Maria, requiring accommodations in throughputs and process design at Rodeo, e.g., contributing to propane and butane that would be recovered at Rodeo with the Propane Recovery Project. The DEIR does not disclose any refinery design changes at either location. Thus, the DEIR is either deficient in this regard, i.e., for not disclosing design changes and their impacts, or Bakken crude is not a serious option.

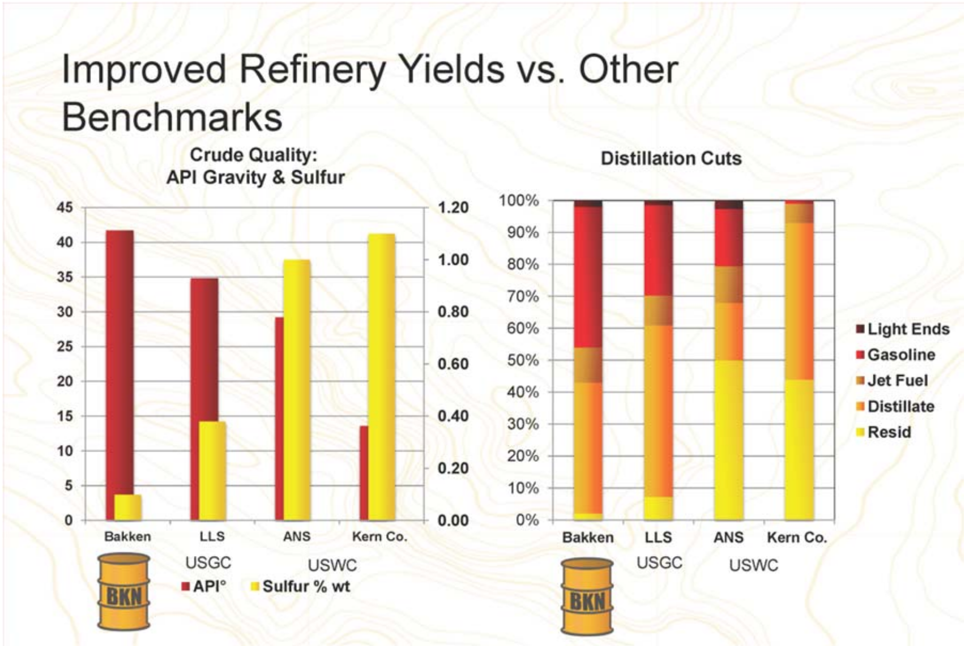
All refineries have criteria for accepting crudes for processing. These were not disclosed in the DEIR and should have been as environmental impacts cannot be fully assessed without them. The switch from a heavy high sulfur crude (current) to very light low sulfur crude (Bakken) would require process design changes, such as changes to the distillation units, idling of the coker and sulfur recovery units, and new tankage. The DEIR does not disclose any refinery design changes.

Bakken crude[10] is a "light" (i.e., very volatile) crude with a high API gravity (>40^{o}) and very low sulfur content (<0.2%)[11] that is not similar to the current crude

[10] Cenovus, Bakken Light Crude Oil, Available at: http://www.cenovus.com/contractor/docs/CenovusMSDS_BakkenOil.pdf. See also crude composition data at: Enbridge Pipelines Inc. 2013 Crude Characteristics No. 44, Available at: http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2013%20Mainline%20Crude%20Characteristics.pdf.

feedstock shown in Table 1. When refined, it yields very little residuum (coker feed) and large amounts of gasoline. Figure 3 The current slate, which is similar to the Kern County crude shown in Figure 3, consists of heavy (API 19°) (i.e., not volatile), sour (4.6% sulfur) crude. When refined, it yields large amounts of residuum, which must be processed in the cokers to extract lighter products amenable to pipelines transport and further processing at Rodeo.

Figure 3
Composition of Bakken Compared to
Typical Heavy Crude (Kern)



The Rail Spur Project is being designed to import essentially 100% of the Refinery's permitted daily throughput crude capacity by rail[12] and 73% of its annual

[11] Bakken has recently soured and sulfur content of 0.17-2.0 ppm are now reported. Prices fell with the souring. See https://www.onepetro.org/conference-paper/SPE-141434-MS; http://www.reuters.com/article/2013/05/29/column-kemp-bakken-pipelines-idUSL5N0EA3SU20130529.

[12] In the Rail Spur baseline, assumed to be 2010 to 2012, the Refinery processed an average of 38,029 BPD. DEIR, Table 2.7. The permitted maximum daily throughput in the baseline is 44,500 BPD. DEIR, Table 3.1. The Rail Spur Project is designed to import one unit train per day, carrying up to 2,190,000 gallons or up to 51,143 BPD of crude oil. DEIR, pp. ES-5, 1-4. An FEIR has been issued for a throughput increase project which would increase the daily permit level by 10% to a maximum of 48,950 BPD (DEIR, p. 2-28 and Table 3.2) and the annual throughput from 16,242,500 BPY to 17,866,750 BPY. Throughput FEIR, p. 2-26.

average throughput.[13] While small amounts of Bakken could be blended with locally sourced or heavy high sulfur crudes or imported tar sand crudes without significant refinery design changes, it is unlikely that Bakken would ever comprise a large fraction of the Santa Maria crude slate without major capital projects not disclosed in the DEIR. The Santa Maria Refinery is not designed to process light sweet crude. Further, as discussed elsewhere in these comments, light sweet crudes such as Bakken generally command a premium in the market. Thus, it is unlikely that Bakken crudes would comprise a significant fraction of the Santa Maria slate as long as cheaper Canadian tar sands crudes are available.

A switch to Bakken would require significant modifications at both the Santa Maria and Rodeo Refineries that are not disclosed in the DEIR. The cokers and sulfur recovery unit, for example, would likely be idled or modified to reduce their processing rates if large amounts of Bakken were refined as Bakken contains very little residuum, *i.e.*, the coker feed, and very little sulfur. New storage tanks would be required, or an increase in permitted throughputs of existing storage tanks and changes in the design of tank vapor control systems to handle higher vapor pressure materials would be required. The capital investment in most of the existing refining equipment would be lost along with the income from selling sulfur and coke. An entirely different refinery would be required to capture maximum value from Bakken crude. No such changes are disclosed in the DEIR.

Further, emissions from the Refinery and pump stations along the pipeline connecting Santa Maria and Rodeo would be significantly different from those in the baseline. If the crude slate were switched to Bakken, combustion emissions at the Santa Maria Refinery would decrease, offsetting some of the increases in locomotive emissions. However, volatile organic compound (VOC) and hazardous air pollutant (e.g., benzene) emissions from tanks and fugitive components, including pump stations along the pipeline (Santa Margarita, Shandon, Cuesta), would significantly increase, likely enough to trigger PSD review for the rail spur as a major modification. These increases would also result in significant worker and public health impacts.

Changes in the type and amount of semi-refined products sent to Rodeo would also change, resulting in changes in emissions at Rodeo. The DEIR does not disclose any changes in emissions at the Santa Maria or Rodeo Refineries from processing the rail-imported crude. This omission either eliminates Bakken as the major crude import, pointing to a heavy, higher sulfur crude, such as tar sands, or renders the DEIR deficient for failing to analyze the impacts of the crude switch.

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[13] The 2012 throughput was 13,274,829 bbl/year, 3-year average throughput was 13,858,563 bbl/year. The project maximum delivery assuming 250 trains/year @ 73 rail cars/train and 30,000 bbl/car =**13,035,714 bbl/year** or **73%** of the permitted throughput of **17,866,750 bbl/year**. DEIR, p. 2-26.

B. Tar Sands Crudes as Feedstock for the Santa Maria Refinery

Canadian tar sands crudes are a "North American sourced crude" that could be imported by the Rail Spur Project. These crudes are also chemically distinct from the current crude slate. The DEIR does not mention Canadian tar sands crudes, which we believe are the most likely crude source. They are likely not mentioned as tar sands crudes have numerous well documented environmental problems[14] and would not be welcome in California due to their well known adverse impacts. However, the Project design and various other information in the DEIR indicate the Project is being designed to import both tar sands crudes and Bakken crudes. Thus, the DEIR must be revised to evaluate the impacts of importing up to 100% of both crudes, which have different impacts. The evidence indicating the Project is designed to import tar sands crudes is summarized in this comment.

The Project description indicates the Rail Spur Project would import crude oil "sourced from oilfields throughout North America based on market economics and other factors..." DEIR, p. ES-3. Tar sands crudes are North American sourced crudes. Further, as defined by the International Energy Agency, and acknowledged in the Land Use Permit Application, the term "crude oil" comprises crude oil, natural gas liquids, refinery feedstocks, and additives as well as other hydrocarbons (including emulsified oils, synthetic crude oil, <u>mineral oils extracted from bituminous minerals such as oil shale, bituminous sand,</u> etc., and oils from coal liquefaction). Crude oil is a mineral oil consisting of a mixture of hydrocarbons of natural origin and associated impurities, such as sulphur.[15] The DEIR does not propose any condition excluding tar sands crudes. Thus, tar sands crudes cannot be ruled out. In fact, the Project is being designed to import tar sands crude. The evidence supporting this is outlined below.

1. <u>Tank Car Capacity</u>

The Project is designed to use two different sized rail cars in the unit trains: (1) 80 rail cars carrying 23,500 gallons each and (2) 73 railcars carrying 30,000 gallons each. DEIR ES-5. The capacity of a rail car is determined by the weight of the loaded car and the maximum allowed weight on the rail line, which is ultimately determined by the density of the material contained in the car. The maximum allowable weight on most freight rail lines coming out of Canada is 286,000 lbs, including the weight of the car.[16]

For light crudes, such as Bakken, the ideal rail tank car has a capacity of 30,000 to 32,000 gallons, given the 286,000 lb rail line weight restriction. For heavier crudes, such

[14] EIP, Tar Sands: Feeding U.S. Refinery Expansions with Dirty Fuel, June 2008, Available at: http://environmentalintegrity.org/pdf/publications/Tar_Sand_Report.pdf.

[15] http://www.slocounty.ca.gov/Assets/PL/Santa+Maria+Refinery+Rail+Project/phillipslanduse.pdf.

[16] Allowable Gross Weight Map, Available at: http://www.uprr.com/aboutup/maps/attachments/allow_gross_full.pdf. See also 49 CFR 179.13, Tank Car Capacity and Gross Weight Limitation.

as tar sands, the ideal tank car has a capacity of about 25,000 gallons, given this limit.[17] Thus, the Project described in the DEIR contemplates both Bakken and tar sands, as it describes the Project as using tank cars carrying either 23,500 gallons (a classic tar sands railcar) or 30,000 gallons (a classic light crude railcar) of crude oil. The Bakken train configuration option would allow the import of more crude than the permitted maximum daily crude throughput (51,143 BPD vs 48,950 BPD).

2. Hydrogen Sulfide Levels

The DEIR includes an odor impact analysis that assumes “the expected H_2S content of the crude oil vapor could be about one percent” based on the Applicant's expected H_2S content of crude oil vapor. DEIR, p. 4.3-51. This is much higher than H_2S levels in Bakken crude vapors. Bakken crude oil contains less than 0.2% H_2S and the headspace vapors would be significantly lower. Thus, the Applicant is expecting to import high H_2S crudes. Tar sands crudes contains high H_2S concentrations.[18]

3. Vapor Pressure Limits

Phillips 66 asserted in its responses to comments on the Draft EIR for the Propane Recovery Project at Rodeo that: “Prior to shipment of the intermediates produced at Santa Maria, the semi-refined material is stored in tankage. The tankage has vapor pressure limits imposed by the County Air District which acts as a constraint regarding how much butane/propane can be included in the intermediates. Accordingly... no new propane/butane can be added to the intermediates sent from Santa Maria to Rodeo regardless of the types of crude that may be processed at Santa Maria.”[19] If true, this eliminates Bakken as a crude that would imported by the rail spur, as it contains high concentrations of volatile components that would significantly increase vapor pressure of material stored in tanks. This points to the import of tar sand crudes, which are similar to the heavy crudes currently refined at Santa Maria.

4. Cost-Advantaged Crudes

The DEIR indicates one of the purposes of the Project is to obtain “competitively priced crude oil.” DEIR, p. 2-30. Tar sands and Bakken are both “competitively priced”, cost-advantaged crudes because they are stranded, with no pipeline access and thus must be delivered by rail.[20] As refineries are not equipped to take delivery of large amounts of

[17] Association of American Railroads, Moving Crude Petroleum by Rail, May 2013, p. 10.

[18] http://www.crudemonitor.ca/home.php.

[19] 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, Re: Phillips 66 Propane Recovery Project, p. 6, January 6, 2014, Available at: http://64.166.146.155/docs/2014/BOS/20140121_330/16707_Exhibit7-P66Response.pdf.

[20] Small amounts of Canadian tar sands crudes are currently arriving on the west coast by ship. However, the pipeline capacity to transport the tar sands crude to the west coast and the rail capacity to transport it to the west coast for subsequent water delivery is currently very limited. However, projects are underway to

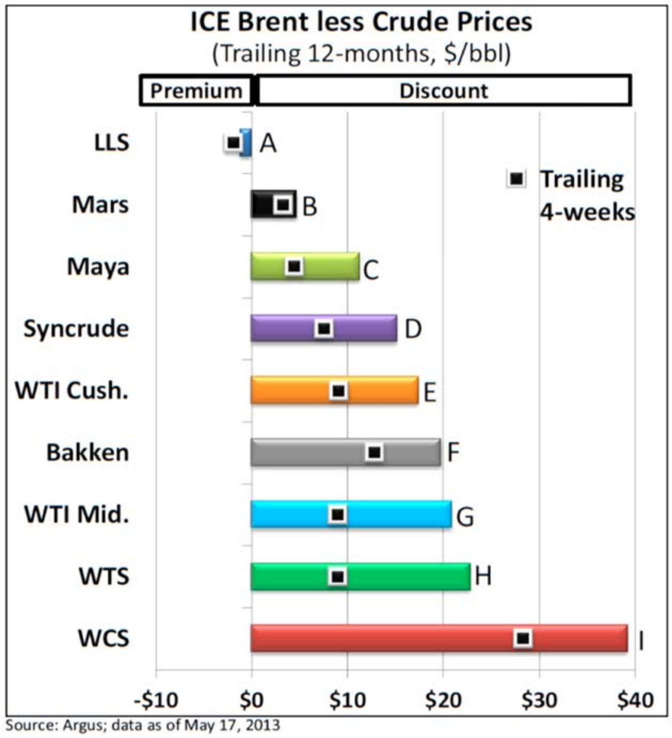
crude by rail, which requires large unit trains, significant infrastructure improvements, such as the Santa Maria Rail Spur Project, are required to import them to the west coast. The most cost advantaged of those available is tar sands crudes, which are both closer to Santa Maria and have less value in the refining market due to their composition, which is similar to the heavy sour crudes now processed at Santa Maria.

Cost-advantaged crude sells at a discount relative to crude oils tied to the global benchmark, North Sea Brent crude. A recent presentation by a Phillips 66 competitor identified tar sands crudes as the most competitively priced crudes to import into the California market by rail.[21] The cost-advantaged crude oils identified by Valero are shown in Figure 4.

alleviate these bottlenecks, including a Phillips 66 project at its Ferndale facility in Washington. The Ferndale project would allow direct import of tar sands crude at the Rodeo Marine Terminal.

[21] Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 10, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx. provided as Appendix D to TGG Comments.

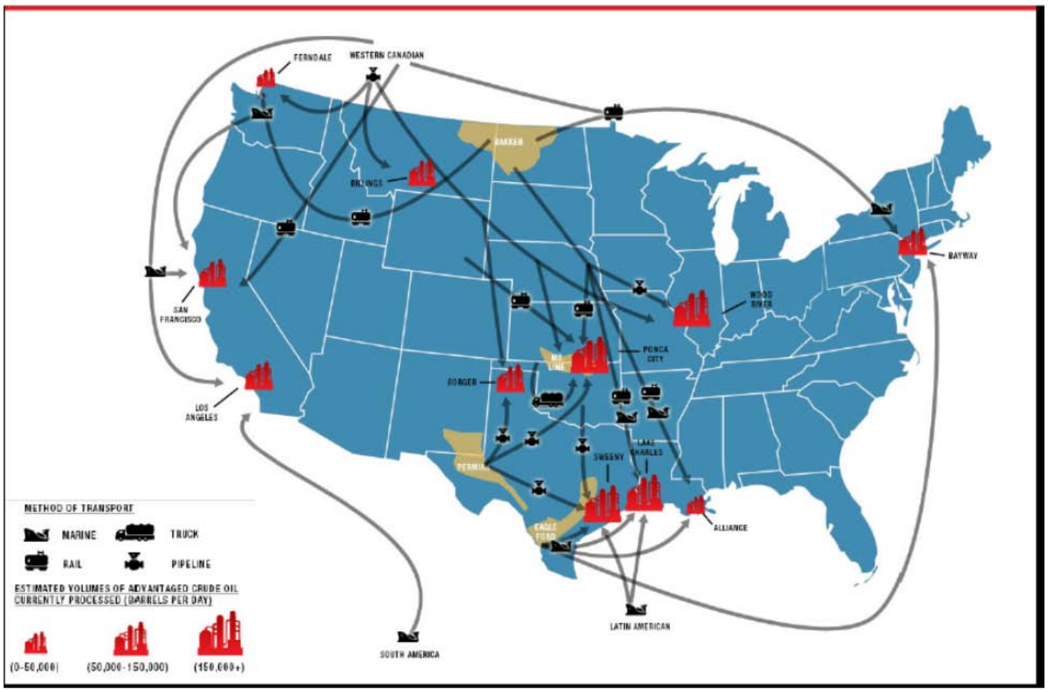
Figure 4
Cost-Advantaged Crudes
That Could Be Imported By Rail[22]



[22] **Brent** is light sweet crude oil sourced from the North Sea, priced at export point there. It has an API gravity of 37.9° and 0.45% sulfur. **LLS** is light Louisiana sweet, priced at St. James, LA. It has an API gravity of 37.0° and 0.38% sulfur. **MARS** is a medium sour blended crude marketed into the Gulf coast and mid-continent regions, priced at Clovelly LA. It has an API gravity of 28.7° and 1.8% sulfur. **Maya** is a heavy sour crude oil from Mexico, priced at export point there. It has an API gravity of 22° and 3.3% sulfur. **WTI Cush.** is West Texas Intermediate crude priced at Cushing, OK, a major trading hub for crude oil. It is a light crude oil with an API gravity of 39.0° and 0.4% sulfur (see also http://en.wikipedia.org/wiki/West_Texas_Intermediate). **WTI Mid**. is West Texas Intermediate (API gravity of 39.0° and 0.4% sulfur) priced at Midland TX (proximate to Permian Basin production). **WTS** is west Texas Sour priced at Midland, TX and an API gravity of 33.5° and 1.9% sulfur. **Syncrude** is a light sweet synthetic Canadian tar sands crude consisting of a bottomless blend of hydrotreated naphtha, distillate, and gas oil fractions produced from a coker and hydrocracker based upgrader facility in Canada; priced at Edmonton Alberta. It typically has an API gravity of 31.0° to 33.0° and 0.1% to 0.2% sulfur (see also http://www.crudemonitor.ca/crude.php?acr=SYN). **WCS** is Western Canadian Select, priced at Hardesty, Alberta. This is a tar sands DilBit crude with API gravity of 20.0° to 21.0° and 3.4% to 3.7% sulfur (see also http://www.crudemonitor.ca/crude.php?acr=WCS).
Sources: Valero crude price data (in Figure 2) are sourced to Argus, so crude specifications in this footnote are based on Argus Methodology and Specifications: Americas Crude (Last Updated: May 2013) http://media.argusmedia.com/~/media/Files/PDFs/Meth/argus_americas_crude.pdf and (for Brent) Argus Crude (Updated: June 2013) http://media.argusmedia.com/~/media/Files/PDFs/Meth/argus_crude.pdf, The pricing locations specified are those shown in Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 8, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx, provided as Appendix D to TGG Comments.

The largest growth in cost-advantaged crudes is coming from U.S. shale crudes and heavy Canadian tar sands crudes, both of which are "North American-sourced crude oils." Valero's list of cost-advantaged crudes in Figure 4 indicates that the most cost-advantaged crude is Western Canadian Select (WCS).[23] A recent Phillips 66 presentation, Figure 5, indicates it is clearly considering Canadian tar sands crude options.[24]

Figure 5
Phillips 66 Cost Advantaged Crude Activities



Western Canadian Select is a "DilBit", which is Canadian tar sands bitumen diluted to pipeline specifications with 25% to 30% diluent. The diluent is typically natural gas condensate, pentanes, or naphtha.[25] Most of the tar sands crudes are too heavy to flow in a pipeline or to be transported in the type of railcars proposed for the Project (i.e., no steam coils or steaming facilities at Santa Maria). Thus, they must be

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[23] Cenovus Energy, Western Canadian Select (WCS) Fact Sheet, Available at: http://www.cenovus.com/operations/doing-business-with-us/marketing/western-canadian-select-fact-sheet.html. See also CrudeMonitor.ca - Canadian Crude Quality Monitoring, Available at: http://www.crudemonitor.ca/crude.php?acr=WCS.

[24] Phillips 66, Crude by Rail & Intermodal Supply Chain, Optimization and Opportunities, Refiner-Led Summit 2013, Opening Keynote Panel, August 21, 2013.

[25] 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.

diluted or thinned with a lighter hydrocarbon stream to reduce viscosity and density to meet pipeline specifications.

The potential rail import of DilBits cannot be eliminated and is the most likely rail import due to economic considerations. The failure to disclose the potential import of tar sands crudes, which are chemically distinct from the current crude slate, is a significant omission as the emissions from handling this material are different from the baseline crude slate. The emissions of some pollutants, VOCs and HAPs, for example, are large and will result in significant air quality, odor, and worker and public health impacts.

Western Canadian Select sells for a discount of nearly $40/bbl compared to ICE Brent.[26] Assuming Valero's reported light crude rail delivery cost of about $13/bbl to $15/bbl,[27] WCE would arrive at Santa Maria at a discount of about $23/bbl to $25/bbl relative to ICE Brent. Rail delivery costs for heavy crude would be somewhat higher, and heavy, sour crudes are less valuable than Brent (the global benchmark for light, sweet crudes). Still, the price of WCS delivered to Santa Maria is likely lower (and very likely competitive), compared with all the other cost-advantaged crudes (Fig. 4). Thus, the most likely crude to be imported by rail is one of the tar sands crudes, which are compatible with the design of the Santa Maria Refinery.

The cost advantage of delivering North American-sourced light sweet crudes (e.g., Bakken) by rail is less than for tar sands crudes. The North American light crudes are discounted less relative to conventional light sweet crudes (ICE Brent) as North American light crudes have more desirable qualities and are further away from Santa Maria than Canadian tar sands. The cost advantage of these crudes, e.g., Bakken, may be small (or completely disappear) after adding the cost of transport by rail to Santa Maria. However, the competitive position of Bakken (and other crudes) will depend in part on the pricing dynamics in the crude markets,[28] and also how specific refineries are configured.[29] Thus, Bakken cannot be eliminated and must be analyzed in the DEIR.

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[26] Brent crude is a major trading classification of sweet light crude oil sourced from the North Sea. Brent is the leading global price benchmark for Atlantic basin crude oils and is used to price two thirds of the world's internationally traded crude oil supplies. It contains about 0.37% sulfur and has an API gravity of 38.06°. It is traded on the electronic IntercontinentalExchange, know as ICE. See: http://en.wikipedia.org/wiki/Brent_Crude.

[27] Valero, May 21-22, 2013, p. 11. This is consistent with recently reported rail delivery rates to Los Angeles of $9.50 - $10.50/bbl (Tesoro, Deutsche Bank Energy Conference, January 9, 2014, pdf 14).

[28] Crude pricing is highly dynamic and varies in part based on crude flows. To the extent that California (and other North American coastal markets) are importing Brent and other waterborne crudes, delivered costs typically include a small premium to cover the cost of importing the crudes by tanker. In Valero's analysis in Figure 4, Brent-priced crude is assumed to be imported into East Coast US (PA/NJ), with the delivered price there at a $2 premium over Brent. Market analysis typically assumes that overseas tanker delivery (e.g., from Brent to East or Gulf Coast) costs about $2/barrel.

[29] Bakken and other light, sweet shale crudes are especially attractive for less complex refineries that are configured for light, sweet crudes, as opposed to more complex refineries that can process heavier, sour feedstocks.

IV. ENVIRONMENTAL IMPACTS FROM CRUDE SLATE CHANGES NOT EVALUATED

The Project would replace up to 100% of the current crude slate with crudes imported from other unidentified and chemically distinct sources, e.g., Bakken light sweet crudes or Canadian tar sands crudes. The environmental impacts of refining depend upon the composition of the crude slate, as discussed elsewhere in these comments. The specific chemicals emitted during refining depend upon the chemicals in the starting crude. Thus, the composition of the baseline crude slate is essential to determine environmental impacts.

A. Why Crude Slate Composition Matters

The Project proposes to dramatically change 100% of the crude slate, from heavy high sulfur locally sourced crudes to light low sulfur crude or heavy high sulfur tar sands crudes. However, the DEIR is silent on the composition of these new crude(s) that would be imported by rail and the resulting impacts relative to the baseline crude slate. The composition of the crude slate determines air quality, worker and public heath, risk of upset, and other impacts of the Project and must be disclosed. The specific chemicals emitted during refining depend upon the chemicals in the starting crude. Thus, the composition of the baseline crude slate is essential to determine environmental impacts.

Volatile chemicals in the crude, such as benzene, hydrogen sulfide, and mercaptans, for example, are emitted from tanks, pumps, connectors, and valves that transport, store and process the crude. Total crude sulfur content as reported in the DEIR cannot be used to evaluate odor and health impacts from transport, storing, and processing this crude as the impacts depend upon the concentration of specific sulfur compounds in rail-imports versus the current slate, e.g., the amount of hydrogen sulfide and mercaptans, which most commonly cause odor problems at refineries. The DEIR does not relate even the single crude analysis to any of its impact analyses. In fact, the DEIR did not analyze any of the impacts of a crude switch.

Hazardous air pollutants or HAPs (e.g., benzene) and other Toxic Air Contaminants (TACs (e.g., H_2S) are present in the crude slate and its semi-refined byproducts. These are emitted from thousands of fittings, valves, pumps, compressors, vents, and tanks at the Refinery and along the pipeline connecting Santa Maria and Rodeo. These emissions were not evaluated in the DEIR.

Refining rearranges the composition of the crude to make marketable products. This requires the input of electricity, heat, and steam. These are generated by burning fuel, which releases large amounts of greenhouse gases, nitrogen oxides (NOx), sulfur oxides (SOx), and other chemicals of concern. The amount of electricity, heat and steam depend upon the chemicals in the crude. Some of the potential "North American sourced crudes" may require much more electricity, heat, and steam to refine than the current slate, increasing emissions and other impacts relative to the baseline crude slate.

B. Crude Slate Baseline Is Not Identified

As this Project involves replacing up to 100% of the current crude slate with dramatically different crudes, baseline crude composition must be reported and impacts must be estimated for the crude switch, relative to baseline crudes. The DEIR does not include baseline crude composition nor does it evaluate any environmental impacts resulting from importing a new crude slate.

The DEIR only includes one analysis of a current crude, a sample collected in March 2008, which is not even in the baseline years and is incomplete. See Table 1. It is unknown where the sample was collected, how it was analyzed, and how it relates to the long-term average slate in the baseline years 2010 - 2012. The Santa Maria Refinery processes crudes from many local and offshore sources that change over time. Is the sample in Table 1 of just one of these crudes, or is it the typical blend that is refined in the baseline? Regardless, one snapshot sample is not sufficient to establish the 2010 - 2012 baseline crude composition.

Further, the reported crude sample data is just for gross lumped parameters such as API gravity and total sulfur content. These lumped parameters are not useful for evaluating environmental impacts. The specific chemicals in the crude and their concentrations are required to evaluate impacts. A good crude assay is essential for comprehensive crude oil evaluation.[30] The type of data required to evaluate emissions would require, at a minimum, the following information for both the current slate and the unidentified “North American-sourced crudes”:

- Trace elements (As, B, Cd, Cl, Co, Cr, Cu, Hg, Mn, Mo, Ni, Pb, Sb, Se, U, V, Zn)
- Nitrogen (total & basic)
- Sulfur (total, mercaptans, H_2S)
- Residue properties (saturates, aromatics, resins)
- Acidity
- Aromatics content
- Asphaltenes (pentane, hexane and heptane insolubles)
- Hydrogen content
- Carbon residue (Ramsbottom, Conradson)
- Distillation yields
- Properties by cut

[30] CCQTA February 7, 2012, p. 10.

- Hydrocarbon analysis by gas chromatography
- Flammability

This type of information is reported in a crude assay or "fingerprint" of the oil, which are likely available to Phillips 66 but were excluded from the DEIR, foreclosing any meaningful public review of environmental impacts. The DEIR does not identify any specific "North American-sourced crudes" that would be imported, contains only a single, limited crude assay for the current refinery slate which is inadequate to assess the baseline (a 2 year period, not a snapshot sample), or the crude(s) that would be imported by rail. The DEIR also does not contain an analysis of the impact of changes in crude quality on air emissions, odor impact, worker and public health impact, risk of upset, and other impact areas. Thus, the public is left to guess what the impacts might be.

The DEIR should have evaluated the impacts of refining the alternate crude slates the Project is being designed for, as reflected in the unit train specifications. These include both light sweet Bakken and heavy sour tar sands crudes. Alternatively, the DEIR should evaluate these impacts and include mitigation conditions prohibiting their import as publicly available information indicates that Phillips 66 is considering both as they would likely arrive at the Refinery with pricing that is competitive relative to other crudes.

The specific chemicals in the crude, for example, determine which ones will be volatile and lost through equipment leaks and outgassed from tanks, which ones will be difficult to remove at Santa Marian and Rodeo (thus determining how much hydrogen and energy must be expended to remove them), which ones will cause malodors, and which ones might aggravate corrosion, leading to accidental releases from pipelines and other refinery equipment.

V. SIGNIFICANT IMPACTS OF CRUDE SLATE CHANGES NOT DISCLOSED

The Project would change up to 100% of the baseline crude slate from locally sourced heavy high sulfur crudes to a light low sulfur crude or heavy high sulfur tar sands crudes. None of the impacts of the crude switch were disclosed in the DEIR nor any of the information required to assess these impacts.

A. Impacts From Unique Suite Of Sulfur Compounds Not Evaluated

The DEIR reports the amount of total sulfur in a single sample of a currently refined crude. The DEIR also analyzes the odor impacts of unloading an unidentified crude, assuming a crude vapor concentration of 1% H_2S (9600 ppm). DEIR, p. 4.3-51 and Appx. B, p. B-10. The basis for this assumption, e.g., the type of crude and the identification and concentration of all sulfur compounds in its vapors were not disclosed. Odor impacts were just evaluated for unloading, but nowhere else, e.g., crude tanks at the Refinery, processing units within the Refinery. Worker and public health impacts from emissions of sulfur species were not identified nor were risk of accidents from sulfur-induced corrosion.

The DEIR's assumption that 100% of the sulfur is H_2S is wrong. Sulfur in the potential import crudes comprises a complex collection of individual chemical compounds including hydrogen sulfide, mercaptans, thiophene, benzothiophene, methyl sulfonic acid, dimethyl sulfone, thiacyclohexane, etc. Each crude has a different suite of individual sulfur chemicals. The environmental impacts of "sulfur", including odor, health impacts and risk of upset, depend upon the specific sulfur chemicals and their relative concentrations, not on the "gross" amount of total sulfur expressed as weight percent sulfur in the crude oil, or only as H_2S in unidentified crude vapors.

The role of specific sulfur compounds was clearly and tragically demonstrated in the recent (August 2012) catastrophic accident at the Chevron Richmond Refinery. This accident was caused by the erroneous assumption that sulfur is sulfur, which led to significant corrosion. See next comment. Similarly, while the lighter sulfur compounds such as mercaptans and disulfides found in light sweet crudes may not significantly increase the overall weight percent sulfur in the crude slate, they do lead to impacts, such as aggressive sulfidation corrosion, which can lead to accidental releases. These compounds concentrate in the lower boiling naphtha fractions produced at Santa Maria and would contribute to aggressive sulfidation corrosion in the convection section of naphtha hydrotreating furnaces at Rodeo.[31]

The specific sulfur compounds in a crude also will determine which compounds will be emitted from storage tanks and fugitive component, some of which could result in significant odor impacts, e.g., mercaptans, and health impacts. The DEIR is silent on sulfur speciation, lumping all sulfur into only H_2S. DEIR, pp. 4.3-51, B-5.

Regardless of what crude might be brought in by rail, there are potentially significant environmental impacts that will result due to the unique sulfur speciation profile of each crude that have not been disclosed in the DEIR. The DEIR lumps all sulfur compounds together.

B. Accidental Releases From The Refinery May Increase

The Santa Maria Refinery was 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. Thus, the metallurgy used throughout much of the Refinery is likely not 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

[31] See, for example, Jim McLaughlin, Changing Your Crude Slate, Becht New, May 24, 2013, Available at: http://becht.com/news/becht-news/.

Refinery in Richmond suggest required metallurgical upgrades are ignored, leading to catastrophic accidents.[32] The DEIR is silent on corrosion issues and metallurgical conditions of the Refinery.

Both DilBit and SynBit crudes, which are cost-advantaged North American crudes that could be imported by rail, have high Total Acid Numbers (TAN), which indicates high organic acid content, typically naphthenic acids. These acids are known to cause corrosion at high temperatures, such as occur in many refining units, e.g., in the feed to cokers. As a rule-of-thumb, crude oils with a TAN number greater than 0.5 mgKOH/g[33] are considered to be potentially corrosive and indicates a level of concern. A TAN number greater than 1.0 mgKOH/g is considered to be very high. Canadian tar sands crudes are high TAN crudes. The DilBits, for example, range from 0.98 to 2.42 mgKOH/g.[34]

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

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.

This recently occurred at the Chevron Richmond Refinery in the San Francisco Bay. 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. The sulfur composition at Chevron Richmond significantly changed over time.[35] 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 release sent 15,000 people from the surrounding area for medical treatment due to the release and created huge black clouds of pollution billowing across the San Francisco Bay.

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[32] 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/.

[33] 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.

[34] www.crudemonitor.ca.

[35] US Chemical Safety and Hazard Investigation Board, 2013, 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.").

These types of accidents can be reasonably expected to result from incorporating tar sands crudes into crude oils processed at the SMR. Even if the range of sulfur and gravity of the crudes remains the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high TAN and high solids, which aggravate corrosion. The gas oil and vacuum residue piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from tar sands crudes, leading to catastrophic releases.[36] Catastrophic releases of air pollution from these types of accidents were not considered in the IS/MND.

Refinery emissions released in upsets and malfunctions can, in some cases, be greater than total operational emissions recorded in formal inventories. For example, a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.[37]

C. Emissions From Diluent Were Not Evaluated

The majority of the crudes that will be imported by rail will likely be a blend of bitumen and diluent due to their discounted price compared to conventional light sweet crudes such as Bakken. Pure undiluted tar sands bitumen is unlikely as the Project description does not disclose any equipment that would be necessary to handle pure bitumen, e.g., rail cars with steam soils, steaming facilities. Undiluted bitumen would eliminate the diluent impacts discussed in this section, but would significantly increase the impacts from refining the heavy ends from increased use of utilities that increase combustion emissions. Setting aside undiluted bitumen, this leaves the question of the amount of diluent that would be mixed with the crude, which ultimately determines impacts.

When heavy crude is shipped by pipeline, it needs to be diluted so that it will flow in the pipe. Bitumen blended to pipeline specifications can be loaded on and off conventional rail tank cars like other light crudes. However, bitumen can also be transported by rail as "RailBit", using 15% to 20% diluent. The amount of diluent depends on the type of rail tank car and design details of the offloading facilities, which are not disclosed in the DEIR, which suggests conventional rail cars designed for DilBits and a conventional unloading terminal. Thus, I assume that one of the materials that will be transported by rail is conventional pipeline-quality DilBits with 20% to 30% diluent.

The mixture of diluent and bitumen does not behave the same as a conventional heavy crude, such as present in the current crude slate, because the distribution of hydrocarbons is very different. The blended lighter diluent generally evaporates readily

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

[37] 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.

when exposed to ambient conditions, leaving behind the heavy ends, the vacuum gas oil (VGO) and residuum.[38] Thus, when a DilBit is released accidentally, it will generally create a difficult to cleanup spill as the heavier bitumen will be left behind.[39] Further, in a storage tank, the diluent also can be rapidly evaporated and emitted through tank openings, emitting high amounts of VOCs and HAPs.

These conventional DilBits, which are the most likely "North American-sourced crudes" to be imported by rail over the long term, given the current economic outlook, 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.[40] This means these crudes have a lot of material boiling at each end of the boiling point curve, but little in the middle. Thus, they 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 distinguish DilBits from crudes currently refined at Santa Maria.[41] Thus, they could generate more coke than the current crude slate, which was not disclosed in the DEIR.

The large amount of light material that distills below 149 C is very volatile and can be emitted to the atmosphere from storage tanks and equipment leaks of fugitive components (pumps, compressors, valves, fittings) in much larger amounts than other heavy crudes that it would replace. The DEIR does not indicate whether other heavy crudes processed at the Refinery currently arrive with diluent. Thus, the use of diluent to transport tar sands crudes is likely an important difference between the current heavy crude slates processed at the Refinery and the tar sands crudes that could replace them. This diluent will have impacts during railcar unloading as well as within the Refinery.

The diluent is a low molecular weight organic material with a high vapor pressure that contains high levels of VOCs, sulfur compounds, and HAPs. These would be emitted during unloading and present in emissions from the crude tank(s) and fugitive components from its entry into the Refinery with the crude until it is recovered and marketed at Rodeo. The presence of diluent would increase the vapor pressure of the

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[38] The residuum is the residue obtained from the oil after nondestructive distillation has removed all of the volatile materials. Residua are black, viscous materials. They may be liquid at room temperature (from the atmospheric distillation tower) or almost solid (generally vacuum residua), depending upon the nature of the crude oil.

[39] 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.

[40] 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.

[41] Stratiev and others, 2010, Table 1, compared to DilBit crude data on www.crudemonitor.ca.

crude, substantially increasing VOC and HAP emissions from tanks and fugitive component leaks compared to those from displaced heavy crudes not blended with diluent and does not address diluent-derived emissions.

The composition of some typical diluents/condensates is reported on the website, www.crudemonitor.ca.[42] The specific diluents that would be present in imported crudes is unknown. The CrudeMonitor information indicates that diluents contain very high concentrations (based on 5-year averages, v/v basis) of the hazardous air pollutants (HAPs) benzene (7,200 ppm to 9,800 ppm); toluene (10,300 ppm to 25,300 ppm); ethyl benzene (900 ppm to 2,900 ppm); and xylenes (4,600 ppm to 23,900 ppm).

The sum of these four compounds is known as "BTEX" or benzene-toluene-ethylbenzene-xylene. The BTEX in diluent ranges from 27,000 ppm to 60,900 ppm. The BTEX in DilBits, blended from these materials, ranges from 8,000 ppm to 12,300 ppm.[43] Similarly, the BTEX in synthetic crude oils (SCOs) ranges from 6,100 ppm to 14,100 ppm.[44] These are very high concentrations that were not considered in the emission calculations in the DEIR or the health risk assessment. These high levels could result in significant worker and public health impacts.

The DEIR does not disclose the BTEX concentrations in the baseline crude slate nor the BTEX concentrations in the range of crudes that could be imported. Rather, it contains only a single mass fraction crude vapor speciation profile that is used only to estimate canister ROG emissions from unloading of trains. However, BTEX from the crude would be emitted from nearly every tank and fugitive component in the Refinery. The DEIR did not evaluate the worker or public health impacts from these emissions anywhere at the facility. Benzene is a carcinogen, the principal one that would be

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

[43] DilBits: Access Western Blend (AWB) - http://www.crudemonitor.ca/crude.php?acr=AWB; Borealis Heavy Blend (BHB) - http://www.crudemonitor.ca/crude.php?acr=BHB; Christina Dilbit Blend (CDB) - http://www.crudemonitor.ca/crude.php?acr=CDB; Cold Lake (CL) - http://www.crudemonitor.ca/crude.php?acr=CL; Peace River Heavy (PH) - http://www.crudemonitor.ca/crude.php?acr=PH; Seal Heavy (SH) - http://www.crudemonitor.ca/crude.php?acr=SH; Statoil Cheecham Blend (SCB) - http://www.crudemonitor.ca/crude.php?acr=SCB; Wabasca Heavy (WH) - http://www.crudemonitor.ca/crude.php?acr=WH; Western Canadian Select (WCS) - http://www.crudemonitor.ca/crude.php?acr=WCS; Albian Heavy Synthetic (AHS) (DilSynBit) - http://www.crudemonitor.ca/crude.php?acr=AHS.

[44] SCOs: CNRL Light Sweet Synthetic (CNS) - http://www.crudemonitor.ca/crude.php?acr=CNS; Husky Synthetic Blend (HSB) - http://www.crudemonitor.ca/crude.php?acr=HSB; Long Lake Light Synthetic (PSC) - http://www.crudemonitor.ca/crude.php?acr=PSC; Premium Albian Synthetic (PAS) - http://www.crudemonitor.ca/crude.php?acr=PAS; Shell Synthetic Light (SSX) - http://www.crudemonitor.ca/crude.php?acr=SSX; Suncor Synthetic A (OSA) - http://www.crudemonitor.ca/crude.php?acr=OSA; Syncrude Synthetic (SYN) - http://www.crudemonitor.ca/crude.php?acr=SYN.

emitted by the Project.[45] These emissions would results in significant worker and public health impacts.

Table 2
Comparison of BTEX Levels
in Potential Crude Imports

	Current Crude Slate (in crude vapors) DEIR, p. B-5 (wt.%)[46]	Diluents (5-yr Avg)[47] (wt.%)	Christina DilBit[48] (5-yr Avg) (wt.%)	Western Canadian Select[49] (5-yr Avg) (wt.%)	Bakken[50] Crude (wt.%)
Benzene	?	0.83-1.27	0.27	0.15	0.1-1.0
Ethylbenzene	?	0.11-0.33	0.06	0.06	0.33
Toluene	?	1.32-2.89	0.44	0.27	0.92
Xylenes	?	0.59-2.71	0.34	0.27	1.4

The CrudeMonitor information also indicates that these diluents contain elevated concentrations of volatile mercaptans (9.9 to 103.5 ppm), which are highly odiferous and toxic compounds that will create odor and nuisance problems at the Refinery in the vicinity of the unloading area, crude storage tanks and supporting fugitive components. Mercaptans can be detected at concentrations substantially lower than will be present in emissions from the crude tanks and fugitive emissions from the unloading rack and

[45] Ethylbenzene was classified by OEHHA as a weak carcinogen in 2007.
See: http://oehha.ca.gov/tcdb/index.asp.

[46] DEIR did not report BTEX composition of the crudes.

[47] The reported range includes the following diluents: Condensate Blend, Saskatchewan Condensate, Peace Condensate, Pembina Condensate, Rangeland Condensate, and Southern Lights Diluent. The composition data for all of these diluents is found at http://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, toluene = 0.866.9 kg/m^3, ethylbenzene 866.5 kg/m^3, and the xylenes 863 kg/m^3) to crude oil density in kg/m3, as reported at www.crudemonitor.ca, 5-year average. See also Cenovus Energy Inc. Material Safety Data Sheet, Condensate (Sour) and Condensate (Sweet), Available at: http://www.cenovus.com/contractor/msds.html.

[48] Christina DilBit Blend (CDB) -.http://www.crudemonitor.ca/crude.php?acr=CDB. Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 47.

[49] Western Canadian Select (WCS) - http://www.crudemonitor.ca/crude.php?acr=WCS. Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 47.

[50] Cenovus Energy, Material Safety Data Sheet for Light Crude Oil, Bakken (benzene), Available at: http://www.cenovus.com/contractor/docs/CenovusMSDS_BakkenOil.pdf. Other components of BTEX from Keystone DEIS, Tables 3.13-1 (density) and 3.13-2 (BTEX). Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 47.

related components, including pumps, valves, flanges, and connectors.[51] In fact, mercaptans are added to natural gas in very tiny amounts so that the gas can be smelled to facilitate detecting leaks.

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

D. Increased Combustion Emissions From Tar Sands Bitumen Not Evaluated

Tars sands are one group of crudes that could plausibly be imported by rail, as discussed elsewhere in these comments. The composition of tar sands crudes is chemically different from other heavy crudes currently processed at the Refinery 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 VOCs and toxic chemicals as discussed above and (2) unique chemical composition of the bitumen, the heavy fraction. The previous comment discussed diluent. This comment discusses the unique composition of tar sands bitumens that require more intense processing and thus result in higher emissions.

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

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

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

composition on the resulting emissions from generating increased amount of these utilities.

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.[52] Crudes derived from Canadian tar sands bitumen—DilBits, SCOs and SynBits—are heavier, i.e., have larger, more complex molecules such as asphaltenes,[53] some with molecular weights above 15,000.[54] They generally have higher amounts of coke-forming precursors; larger amounts of contaminants (sulfur, nitrogen nickel, vanadium) that require more intense processing to remove; and are deficient in hydrogen, compared to other heavy crudes.

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

1. Higher Concentrations of Asphaltenes and Resins

The severity (e.g., temperature, amount of catalyst, hydrogen) of hydrotreating depends on the type of compound a contaminant is bound up in. Lower molecular weight compounds are easier to remove. The difficulty of removal increases in this order: paraffins, naphthenes, and aromatics.[55] Most of the contaminants of concern in tar sands crudes are bound up in high molecular weight aromatic compounds such as asphaltenes that are difficult to remove, meaning more heat, hydrogen, and catalyst are required to convert them to lower molecular weight blend stocks. Some tar sands-derived vacuum gas oils (VGOs), for example, contain no paraffins of any kind. All of the molecules are

[52] 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.

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

[54] 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.

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

aromatics, naphthenes, or sulfur species that require large amounts of hydrogen to hydrotreat, compared to other heavy crudes.[56]

Asphaltenes and resins generally occur in tar sands bitumens in much higher amounts than in other heavy crudes. They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[57] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker. They also form layers of coke in hydrotreating reactors, such as those at Rodeo, requiring increased heat input, leading to localized or even general overheating and thus even more coke deposition. This seriously affects catalyst activity resulting in a marked decrease in the rate of desulfurization. They also require more intense processing in the coker required to break them down into lighter products. These factors require increases in steam and heat input, both of which generate combustion emissions -- NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

Further, if the crude includes a synthetic crude, SCO, for example, the material has been previously hydrotreated. Thus, the remaining contaminants (e.g., sulfur, nitrogen), while present in small amounts, are much more difficult to remove (due to their chemical form, buried in complex aromatics), requiring higher temperatures, more catalyst, and more hydrogen.[58]

The higher amounts of asphaltenes and resins generate more heavy feedstocks that require more severe processing than lighter feedstocks. The coker, for example, makes more coker distillate and gas oil, that would contribute to the propane and butane that would be recovered at Rodeo, compared to conventional heavy crudes. Similarly, the Crude Unit makes more atmospheric and vacuum gas oils that would be sent to Rodeo,[59] increasing emissions there, including fugitive VOC emissions from equipment leaks and combustion emissions from burning more fuel.

2. Hydrogen Deficiency

Tar sands crudes are hydrogen-deficient compared to heavy and conventional crude oils and thus require substantial hydrogen addition during refining, beyond that required to remove contaminants (sulfur, nitrogen, metals) from non-tar-sands crudes. This again means more combustion emissions from burning more fuel. As the refining processes that use hydrogen, e.g., hydrotreating, are all located at Rodeo, this is further

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

[57] 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.

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

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

evidence that a crude slate switch involving tar sands would necessarily be directly linked to Rodeo.

3. Higher Concentrations of Catalyst Contaminants

Tar sands bitumens contain about 1.5 times more sulfur, nitrogen, oxygen, nickel and vanadium than typical heavy crudes.[60] Thus, much more hydrogen per barrel of feed and higher temperatures would be required at Rodeo to remove the larger amounts of these poisons from semi-refined products. These impurities are removed by reacting hydrogen with the crude fractions over a fixed catalyst bed at elevated temperature. The oil feed is mixed with substantial quantities of hydrogen either before or after it is preheated, generally to 500 F to 800 F. The amount of hydrogen required for a particular application depends on the hydrogen content of the feed and products and the amount of the contaminants to be removed. Hydrogen consumption is typically about 70 standard cubic foot per barrel (scf/bbl) of feed per percent sulfur, about 320 scf/bbl feed per percent nitrogen, and 180 scf/bbl per percent oxygen removed.[61]

Canadian tar sands crudes generally have higher nitrogen content, 3,000 to >6,000 ppm[62] and specifically higher organic nitrogen content, particularly in the naphtha range, than other heavy crudes.[63] This nitrogen is mostly bound up in complex aromatic compounds that require a lot of hydrogen to remove. This would affect emissions at Rodeo in five ways.

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

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

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

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

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

These types of chemical differences between the current crude slate and the new crude slate facilitated by the Rail Spur Project were not addressed at all in the DEIR. While both the Santa Maria and Rodeo Refineries may currently be operating within their permit limits, and may even continue to do so, the potential subject increases must be measured and evaluated relative to the CEQA baseline.

E. Increased Metal Content Not Evaluated

The baseline slate includes very little tar sands crudes, potentially from 2% to 7% of the crude slate. DEIR, p. 2-27. The Project could increase the import of heavy sour tar sands crude by up to the entire permitted capacity of the Refinery. These crudes have higher metal content than the baseline crude slate. [64] This represents a significant increase in a type of crude that will increase emissions compared to the current Refinery slate. The impacts from this change were not evaluated in the DEIR.

The U.S. Geological Survey ("USGS"), for example, 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.[65]

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. The DEIR indicates that "[m]etals that are present in coke have been detected in grouondwater at concentrations above the California Department of Health maximum contamination levels (MCL) in the area around the coke pile runoff area..." DEIR, p. 4.7-39/40. Thus, a switch to tar sands crude could contribute to this existing significant impact from the coke pile, which was not disclosed in the DEIR.

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

[64] Straatiev and other, 2010, Table 1; Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils, http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF; F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010, Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf .

[65] 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.

as a pollutant with no safe threshold level of exposure below which there are no adverse health effects. Thus, just the increase in lead from switching up to tar sands crude is a significant impact that was not disclosed in the DEIR. Accordingly, crude quality is critical for a thorough evaluation of the impacts of a crude switch, such as facilitated by rail import.

sec. 4.11 public services and utilities, does not address how a local train accident would be handled, given existing services and utilities. It couldn't be, which is a significant unmitigated impact.

VI. HAZARDS AND HAZARDOUS MATERIALS IMPACTS ARE SIGNIFICANT

Section 4.7 of the DEIR contains the "hazards and hazardous materials" impact analyses, sometimes call the risk of upset analysis. This section evaluates two separate impacts: (1) on-site accidents from crude oil unloading through pipeline transport to storage tanks at the Refinery and (2) rail transport accidents. The supporting material includes extensive discussion of the applicable regulatory framework and general methods used to analyze these types of impacts. However, the project-specific results and conclusions appear magically, with no support for or explanation of how the conclusions were reached. The available information indicates that the DEIR's analysis is fatally flawed and the risk of upset impacts are highly significant.

A. Crude Slate Not Disclosed

As explained elsewhere in these comments, the composition of the crude slate must be known to evaluate impacts. This is particularly critical for the analysis of accidents as the probability, severity, and consequences of an accident depend directly on the chemicals in the crude. They determine, for example, the flammability of the crude and its potential to corrode tank cars, pumps, pipelines, tanks, and other equipment hand store and transport the crude. The Federal Railroad Administration, for example, has observed "an increasing number of incidents involving damage to tank cars in crude oil service in the form of severe corrosion of the internal surface of the tank, manway covers, and valves and fittings," and suggested that this may involve contaminated oil.[5] Further, some types of crudes are more challenging to contain and cleanup in the event of an accidental release.

As the DEIR admits: "the thermal radiation hazards from hydrocarbon pool fires depends on a number of parameters, including the composition of the hydrocarbon mixture..." DEIR, p. 4.7-15. The Project involves a dramatic change in crude slate composition, especially its hydrocarbon composition. The crude slate will change from a relatively inflammable material with high molecular weight hydrocarbons to new crudes ranging from light, highly volatile crudes with low molecular weight hydrocarbons such as propane and butane (Bakken) to heavy, highly corrosive tar sands crudes blended with condensates that can cause different types of accidents. See Comments V and VI.B.

The DEIR asserts that "[r]adiative properties of the fire were based on a detailed analysis of typical crude oil that would be delivered by rail". DEIR, p. 4.7-16. However, the DEIR does not identify this crude further. Where is the detailed crude analysis that the fire analyses was based on? What specific crude was analyzed, i.e., was it Bakken or tar sands or something else? How representative is it of the range of crudes that would be imported by rail? Where are the assumed properties used to assess flammability and the resulting analysis itself? What is the basis of the burning rate of 0.228 mm/s assumed for "light crude oil"? DEIR, p. 4.7-16.

The hazards section of the DEIR does not acknowledge that a range of crudes will be imported by rail with widely varying properties, or indicate that crude composition was considered in any other aspects of the various hazard analyses except fire hazard. The DEIR, for example, notes that unloaded crude would be sent by pipeline to "be stored in the existing refinery storage tanks. Therefore, crude oil storage would not result in any increase in fire and explosion risk at the refinery". DEIR, p. 4.7-57. This is wrong because the projected change in crude slate composition will increase the probability of accidental releases from the tank farm and their consequences, as the stored crudes will be either more volatile, flammable, and/or corrosive. The DEIR has failed to analyze these impacts.

B. Risk of Upset Impacts Are Significant

The DEIR evaluated several crude release accident scenarios: (1) tank farm releases; (2) on-site crude railcar accident pool fires; (3) on-site crude railcar accident BLEVES; (4) crude pipeline accident pool fires; (5) off-site train accidents. DEIR, Appx. H. The DEIR suggests that none of these accident scenarios result in significant impacts. DEIR, Sec. 4.7.4.

However, the DEIR buries the supporting analyses in dense appendices that are not accessible to the typical DEIR reviewer. The DEIR fails to explain how to translate the results of these analyses into impact conclusions that can be understood by non-subject-matter experts, thus preventing meaningful public review of the impacts. The DEIR further incorrectly summarizes the results of these analyses in the text as insignificant, when, in fact, they are highly significant. Finally, the DEIR uses the wrong significance thresholds, fails to evaluate the impact of crude slate changes, and fails to evaluate impacts to on-site workers, the most at risk population.

1. <u>Worker Impacts Excluded</u>

The DEIR fails to evaluate the impacts to workers, arguing that "OSHA related worker issues are outside the scope of the EIR." DEIR, p. 4.3-52. The DEIR specifically excludes workers from its risk of upset significance criteria, arguing they do not apply to occupational safety, *viz.*, "Occupational risk, which is governed by state and federal OSHAs is considered to be more voluntary and is generally judged according to more lenient standards of significance than those used for involuntary exposure". DEIR, p. 4.7-55.

However, neither state nor federal OSHA nor other regulations cover the types of involuntary risks imposed by unit train accidents and exploding pipelines and tanks on workers in the vicinity of these facilities. A death is a death and it should not matter whether it is an on-site worker, off-site worker, or other member of the public. A worker is a member of society at large and is protected by CEQA. None of the federal and state laws reviewed in DEIR Section 4.7.2 include any measures to protect any workers, on-site or off-site, from train, pipeline, and tank farm accidents.

Regardless, CEQA is not a gap-filling regulatory program. CEQA covers all impacts to all media -- the public, air, water, land, biological resources -- regardless of how they may be classified, i.e., on-site workers, off-site workers, residents, threatened and endangered species, etc. These types of catastrophic events are entirely outside of the jurisdiction of OSHA or any other federal or state regulatory program and must be evaluated in the DEIR. The DEIR must be revised to address worker impacts and be recirculated.

2. Tank Farm Accidents Are Significant

The DEIR states that imported crude would be sent through a 3,525-foot long pipeline to existing refinery storage tanks, concluding: "Therefore, crude oil storage would not result in any increase in fire and explosion risk at the refinery." DEIR, p. 4.7-57. The DEIR does not contain any analysis to support this assertion. See, for example, Appendix H, which does not include a storage tank scenario, but rather only rail car and pipeline accident scenarios.

This unsupported assertion is incorrect because it assumes no change in properties of stored crude. The Project would change the composition of the crude slate. If highly flammable Bakken crudes were imported, for example, the risk of fire and explosion would significantly increase at the tank farm, impacting not only workers, but also offsite parties. The flammability classification of Bakken is rated at Level 4, the highest flammability classification, the same as for methane and propane gases.[66] On January 2, 2014, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a safety alert addressing the flammability characteristics of crude oil produced from the Bakken Shale formation.[67] Alternatively, if tar sands crudes were imported, corrosion issues could arise at the existing tanks, leading to accidental releases. Neither of these risk scenarios was identified or evaluated in the DEIR.

Rather, the DEIR only contains a description of the existing tank farm. DEIR, Sec. 4.7.1.5, stating: "Thermal radiation impacts from crude oil tank fires could cause injury 220 feet away." DEIR, p. 4.7-37. The DEIR goes on to explain that the closest receptor is further away. Thus, the DEIR asserts: "Given the properties of crude oil, the

[66] Cenovus MSDS sheet for Bakken Crude.
[67] PHMSA, Safety Alert, January 2, 2014: Preliminary Guidance from Operation Classification.

likelihood of an explosion is virtually non-existent and consequently explosion scenarios are not addressed further in this document." DEIR, p. 4.7-37.

However, the analyses supporting the claimed 220-foot injury distance is not included in the DEIR and apparently based on the crude slate currently processed at the Santa Maria Refinery. Further, the nature of the "injury" is not disclosed. Regardless, a switch from current crude to Bakken crude would significantly increase the injury distance, likely far in excess of the 425-foot distance to the nearest receptor. Thus, accidental releases from the tank farm were not analyzed in the DEIR and are likely highly significant.

3. Pipeline Accidents Are Significant

The DEIR contains a crude pipeline accident analysis for a pool fire, assuming a spill of 692,000 barrels of crude for wind speeds of 1 meter per second (m/s) (about 2 miles per hour (mi/hr)) and 20 m/s (about 45 mi/hr). DEIR, Appx. H, pp. H-14 to H-17. This analysis is dismissed with the misleading characterization that "[w]orst-case thermal radiation injury levels would extend approximately 800 meters from the pool fire that could result from a catastrophic pipeline failure on the refinery site. Based on this modeling, it was determined that there would not be any potential for offsite injuries associated with worst-case unloading facility crude oil spill and fire." DEIR, p. 4.7-57.

The supporting analyses are included in Appendix H, in a format that is not accessible to the average reviewer. Thus, they are extracted and summarized in Table 3.

Table 3
Crude Pipeline Accident Pool Fire
(DEIR, Appx. H)

Heat Flux (kW/m2) =	5	10	12.5
Wind Speed (m/s)	**Impact Distance (ft)**		
1	1647	889	764
20	2641	1555	1273

The impact metric in these analyses is "heat flux" expressed as kilowatts per square meters (kW/m^2). Heat flux is thermal radiation intensity, the measure used in the DEIR to determine the resulting injury to exposed parties. DEIR, Table 4.7.2. The DEIR states that it "assumed that all persons exposed to 10 kW/m^2 would suffer serious injuries. Serious injuries would start to be realized at and above 5 kW/m^2... Exposure to thermal radiation levels in excess of 10 kW/m^2 would likely begin to generate fatalities in less than 1 minute. All persons exposed to thermal radiation within the flame area were assumed to suffer fatalities regardless of exposure duration." DEIR, p. 4.7-19. See also DEIR Table 4.7-4. The three heat flux criteria reported in Table -- were selected by the DEIR preparers to evaluate the significance of accident scenarios.

Any population located between the accident site up to the reported impact distance, e.g., as far away as 2,641 feet in Table 3, would experience significant impacts. At a heat flux of 5 kW/m^2, 10% injury would be experienced in the exposed population up to 2,641 feet from the accident if the wind were blowing at 20 m/s during the accident. Up to 1,555 feet from the accident, 100% of the exposed population would be injured, including second-degree burns in 14 seconds and 10% fatality at 60 seconds. And up to 1,273 feet from the accident, significant fatalities would occur.

A pipeline accident could occur anywhere along the pipeline route, but would most likely occur at the tank farm, where the crude oil is transferred into tankage. Assuming a pipeline accident at the tank farm under calm wind conditions (1 m/s or about 2 mi/hr), significant impacts would occur up to 1,647 feet from the accident site. The impacted area includes an industrial area 425 feet northeast of the tank farm and a residence within the industrial area at 1,200 feet. DEIR, p. 4.7-37. At a wind speed of 20 m/s (about 45 mi/hr), all persons up to 2,641 feet away would be seriously impacted and within a radius of 1,273 feet from the accident site, they would all be killed.

Thus, clearly, a pipeline accident involving the new crude slate has the potential to result in significant off-site (as well as even more significant on-site worker) impacts that were incorrectly described in the DEIR. The actual modeling indicates that off-site parties would be killed. This is a significant impact.

4. <u>On-Site Train Accidents Are Significant</u>

The DEIR also included on-site crude rail car accidents resulting in both pool fires and Boiling Liquid Expanding Vapor Explosions or "BLEVEs" for wind speeds ranging from 1 m/s to 20 m/s. DEIR, Appx. H. The DEIR asserts, based on these analyses buried in Appendix H, that "potential hazards associated with the unloading facility are considered less than significant" and "[h]azards associated with the onsite portion of the Rail Spur Project would be *less than significant (Class III*")." DEIR, pp. 4.7-57/58 (emphasis in original). No significance thresholds are articulated to support these conclusions nor is any explanation provided to explain the basis for the DEIR's conclusion.

However, independent analyses based on the railcar accident modeling in Appendix H coupled with significance levels scattered about in the DEIR indicates that the risks from train accidents within the Refinery boundary result in significant on-site and off-site impacts for both pool fires and BLEVEs.

a. Pool Fires

The DEIR analyzes pool fires resulting from a crude railcar accident in which 54,476 barrels of crude (i.e., the entire contents of a unit train) are released for wind speeds ranging from 1 m/s to 20 m/s (2 mi/hr to 45 mi/hr). DEIR, pp. H-2 to H-9. These analyses report "heat flux" in kW/m^2 as a function of distance from the release, for distances of 100 to 1,000 meters (328 to 3,281 feet). An accident could occur anywhere within the Refinery boundary shown on Figure 2-1. The results of the DEIR's railcar pool fire analyses are buried in Appendix H in a format not accessible to the average reviewer. Thus, they are summarized in Table 4.

Table 4
Summary of Crude Railcar Accident Analysis of Pool Fires
(DEIR, Appx. H)

Heat Flux (kW/m2) =	5	10	12.5
Wind Speed (m/s)	**Impact Distance (ft)**		
1	775	407	331
5	876	495	410
10	928	541	446
20	1404	958	810

The interpretation of these data (and other similar data extracted from Appendix H and summarized in these comments) requires a map that shows the location of potentially exposed populations relative to the accident sites (anywhere along the rail line within the Refinery boundary). It is common to include such a map in an EIR to locate the sensitive receptors. However, the DEIR fails to include a sensitive receptor map and is thus deficient. The boundaries of the Refinery are shown in DEIR Fig. 2-1. This figure and Google Earth maps indicate that the northeastern boundary of the Refinery at roughly the elbow of Highway 1, where the Southern Pacific rail line enters the Refinery, abuts industrial and residential property to the east and north and recreational areas in the Coastal Zone to the west. Sensitive receptors are located in these areas, for example, residences along Monadella Street and in areas to the north and south of Highway 1 (Willow Road) and users of the Oceano Dunes State Vehicular Recreation Area and Oso Flaco Lake and Dunes to the west.

The results of the railcar accident modeling summarized in Table 4 indicate that both on-site and off-site impacts are significant. When the wind speed is 20 m/s (45 mi/hr), the heat flux is 5 kW/m^2 at up to 1,404 feet from the accident site and 12.5 kW/m^2 up to 810 feet from the accident site. A comparison of Figures 2-1 and 2-4 indicates that if the accident occurred near the junction of Willow Road and U.S. 1, off-site sensitive receptors would be located within 1,404 feet of the accident site. Thus, significant off-site impacts would occur from an accident within the Refinery boundary.

Further, refinery workers would be present throughout the Refinery and at the unloading facility. These workers would be the most highly exposed populations and would experience significant mortality.

Thus, railcar accidents within the Refinery boundary would result in significant impacts to both on-site and off-site populations. These were not disclosed in the DEIR, but rather buried in a maze of tables that are not explained or analyzed.

b. BLEVES

The DEIR also evaluated the radiant heat exposure and explosion over pressures resulting from a railcar accident involving a Boiling Liquid Expanding Vapor Explosion or "BLEVEs." However, the DEIR fails to discuss the results of this analysis, which is buried in DEIR Appendix H in a format not accessible to the average reviewer. Thus, they are summarized in Table 5.

Heat flux for the BLEVE analysis is reported in the DEIR in units of kilojoules per square meter (kJ/m^2), which is just another measure of heat density, similar to kW/m^2 used to evaluate pool fires, but just expressed in different units. The DEIR explains that at a heat density (or radiation dosage) of 40 kJ/m^2, 10% injury will result, at 150 kJ/m^2, 100% injury will result, and at 250 kJ/m^2, 1% fatalities will occur. DEIR, Table 4.7.4.

Table 5
Results of Radiation Exposure Analysis
from Railcar Accident BLEVE
(DEIR, p. H-13)

Impact Distance (ft)	Radiant Heat Significance Threshold (kJ/m2)
1,690	40
1,194	80
1,066	100
859	150
830	160
643	250

Table 5 shows that significant impacts, 20% injury, will occur at up to 1,690 feet from the accident site. As discussed above, if the accident occurs near the vicinity of the intersection of Highway 1 and Willow Road, within the Refinery boundary, significant impacts will result outside of the Refinery, in industrial/residential areas to the east and in the Coastal Zone areas to the west. Further, workers within 1,690 feet of the accident would also experience significant impacts, and those within 643 feet of the accident may die. These are significant impacts that were not disclosed in the DEIR.

5. <u>Offsite Impacts From Train Accidents Are Significant</u>

The DEIR also evaluated train accident impacts outside of the Refinery, within San Luis Obispo County (SLOC). The DEIR asserts this analysis was prepared following guidelines of the American Institute of Chemical Engineers, Center for Chemical Process Safety (CCPS, 1995) and the parameters discussed in DEIR Section 4.7.1.3. DEIR, p. 4.7-61. However, this analysis does not follow the CCPS method; it uses the wrong significance thresholds; it fails to discuss or analyze in any fashion the factors that actually affect rail accidents; it is totally unsupported; it fails to analyze the most significant impacts, which occur outside of San Luis Obispo County; it is based on outdated information; and it ignores most impacts caused by rail accidents, including the impacts of spilled crude oils to water, land, and biological resources and public health impacts from exposure to toxic fumes and smoke. Each of these issues is discussed below.

a. Significance Threshold

The San Luis Obispo County Initial Study Checklist defines significant risk if the project will "result in a risk of explosion or release of hazardous substances," or "create any other health hazard or potential impact." Rather than use this definition of significant risk, the DEIR sets it aside and adopts a probability-based risk profile curve approach from Santa Barbara County to evaluate risks associated with crude oil unit train transportation. DEIR, p. 4.7-55, Table 4.7.12, Fig. 4.7-5.

This method minimizes the significance of many potential injuries and deaths by assigning probabilities that a certain number of injuries or deaths will occur, based on statistics that do not capture the proposed increase in rail traffic. Under the San Luis Obispo definition, the mere "risk" of an explosion, a release of crude oil, any health hazard or any potential impact is significant. Thus, as there is ample evidence that spectacular accidents involving crude-carrying unit trains with well documented property damage and death have recently occurred, train accidents are per se significant.

The complex (and unsupported) probability-based risk profile method used in the DEIR seeks to downplay the very well documented significant consequences of accidents involving unit train accidents carrying crude oils. These accidents will happen, they will result in significant impacts, and the DEIR should focus on minimizing their occurrence, rather than burying the fact that they do occur in a maze of unsupported and incoherent probability analysis. Further, the DEIR's analysis is based on very out of data information that does not consider recent history.

b. The DEIR Fails To Acknowledge Recent History

The DEIR's analysis is based on outdated accident statistics, from CCSP (1995), published long before the recent surge in the transport of crude oil by rail. Recent history indicates that the accidents involving unit trains carrying crude oil have sky-rocketed. They also demonstrate the unique set of challenges posed by highly flammable materials, such as Bakken crudes, transported in unsafe tanker cars configured in unit trains that are "virtual pipelines" of highly flammable material, which now dominate the industry. Risks are compounded when highly flammable material, such as Bakken crudes, are shipped in large amounts.[68]

[68] National Transportation Safety Board, Safety Recommendation R-14-4 to -6, January 21, 2014, Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

Historically, most crude oil has been transported in pipelines. However, in places like North Dakota and Canada that have seen huge recent increases in crude oil production, the existing crude oil pipeline network lacks capacity to handle the higher volumes being produced. Pipelines also lack the operational flexibility and geographic reach to serve many potential markets, especially the west coast. Railroads, though, have capacity, flexibility, and reach to fill the gap.

Small amounts of crude oil have long been transported by rail, but since 2009 the increase in rail crude oil movements has been enormous. In the United States, crude oil shipments have increased from 10,800 car loads in 2009 to about 400,000 in 2013. In Canada, shipments of crude oil by rail increased from a mere 500 car loads in 2009 to 160,000 car loads in 2013.[69] Continued large increases are expected in 2014. Crude oil accounted for 0.8 percent of total Class I carload originations for all of 2012, 1.1 percent in the fourth quarter of 2012, and 1.4 percent in the first quarter of 2013. It was just 0.03 percent in 2008.[70]

This recent rise in crude transportation by rail has resulted in soaring numbers of crude oil releases to the environment in the form of both accidents and "non-accident" releases such as leaks. The Pipeline and Hazardous Materials Safety Administration (PHMSA) incident records underscore these growing risks. The number of incidents involving crude oil transportation by rail are as follows:

- 2009: 0
- 2010: 9
- 2011: 34
- 2012: 86
- 2013: 85 (partial)[71]

Similar statistics were published by the Wall Street Journal, based on data generated by the Association of American Railroads ("AAR"):[72]

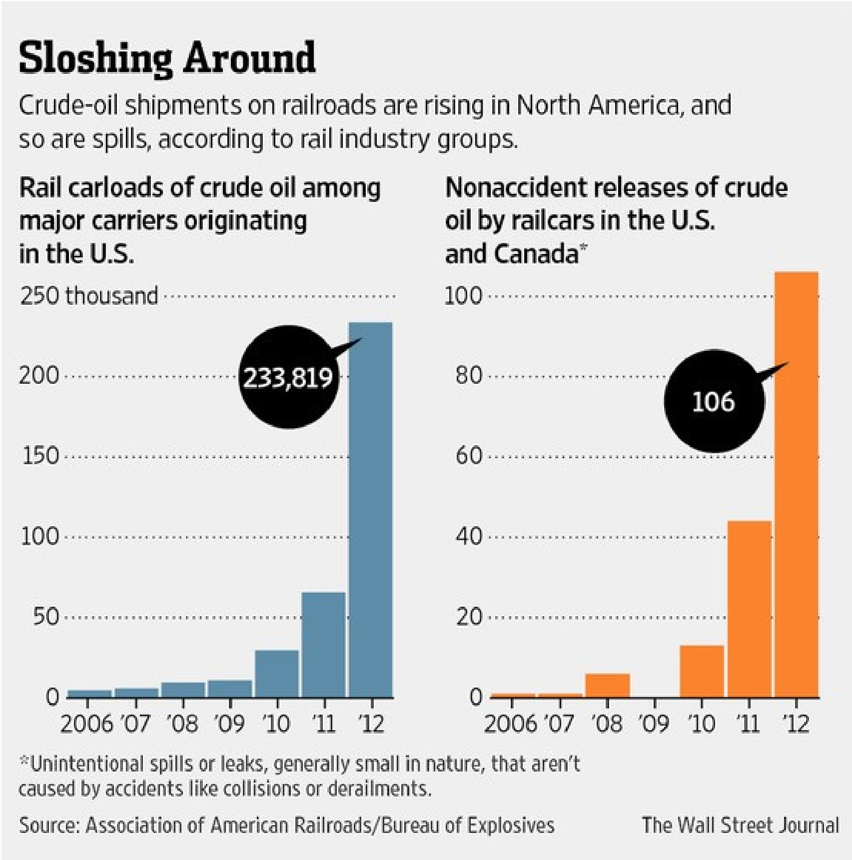
[69] TSBC, Rail Safety Recommendations, January 23, 2014, Available at: http://www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.pdf.

[70] American Association of Railroads, "Moving Crude Petroleum by Rail," https://www.aar.org/keyissues/Documents/Background-Papers/Crude-oil-by-rail.pdf; May 2013, at 3-5.

[71] Data derived from PHMSA incident reports - http://www.phmsa.dot.gov/hazmat/library/data-stats/incidents.

[72] The Wall Street Journal, "Officials Tighten Crude-Shipping Standards," http://online.wsj.com/news/articles/SB10001424127887323838204578654463632065372; August. 7, 2013. (Also included as Attachment 3.)

Figure 6
Industry shipment and incident reports



An article in the January 21, 2014 Contra Costa Times, which serves one of the areas through which the Project's unit trains would pass, similarly explains that more crude oil was spilled in U.S. rail accidents in 2013 than in the nearly four decades since the federal government began collecting data on such spills. More than 1.15 million gallons of crude oil was spilled from rail cars in 2013 alone. By comparison, U.S. railroads spilled a combined 800,000 gallons of crude oil between 1975 and 2012.[73] These data do not include Canada, where more than 1.5 million gallons of crude oil were spilled in the Lac- Mégantic, Quebec accident on July 6, 2013, when a runaway train derailed, exploded, and killed 47 people. The cargo was Bakken crude from North Dakota.

The subject unit trains are "virtual pipelines" that pass through heavily populated residential areas. When such large volumes of flammable crude oil are on a single train involved in an accident, as seen in the Lac-Mégantic accident described below, they explode in spectacular fireballs. The resulting accidents can cause major loss of life, property damage, and environmental consequences. The sharp increase in crude oil rail

[73] Curtis Tate, Data: Oil Spills from Rail Cars Massive, Contra Costa Times, January 21, 2014.

shipments has significantly increased safety risks to the public.[74] Crude oil is problematic when released because it is flammable, especially Bakken crude. The risk is compounded because it is commonly shipped in large amounts. These increased risks have not been evaluated in the DEIR.

Unfortunately, the surge of incidents and releases has not been matched by an increase in the resources available to responders and regulators, pointing to the need for mitigation. The DEIR fails to address the lack of adequate resources anywhere along the rail route, even in SLOC, to address the type of catastrophic accident that is likely to occur. Example of some recent accidents follow.

1. *Lac-Mégantic*

On July 5, 2013, a train hauling 72 DOT-111 tanker cars loaded with 2.0 million gallons of crude from the Bakken shale oil field in North Dakota, one of the crudes proposed to be imported by the Rail Spur Project, slammed into Lac-Mégantic, a town of 6,000 located in Quebec. Owned by an American company – Montreal, Maine and Atlantic Railway – the train had only a single staffer, who abandoned the train in order to sleep in a motel before a replacement crew arrived to complete the train's journey to an oil refinery on Canada's east coast. The brakes on the five-locomotive train malfunctioned, and it began a seven-mile roll toward the small town. Reaching a speed in excess of 60 mi/hr, the train reached a bend in the tracks, derailing and dumping 1.5 million gallons of Bakken crude, which caught fire and incinerated dozens of buildings. Forty-seven people were killed. About 1.6 million gallons of Bakken crude oil were released, covering an area of 77 acres. Oil spilled into the Chaudière River and was transported as far as 74 miles away.[75] While this accident occurred in Canada, the freight railroad operating environment in Canada is similar to that in the United States.

[74] Association of American Railroads, Bureau of Explosives, Annual Report of Hazardous Materials Transported by Rail, BOE 12-1, 2013.

[75] 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.

Figure 7
Post-Accident Aerial Photo of Lac-Megantic (Reuters)

The DOT-111 tanker cars involved in this accident are the same ones that the DEIR suggests will be used to import this very same crude, but notes that "nearly 25 percent of the DOT-111 fleet carrying crude today meets the higher design standards..." DEIR, p. 4.7-15. Will the DEIR's tank car fleet be within the 25% safe or the 75% unsafe DOT-111 fleet?

The DEIR pretends to analyze a similar accident within SLOC, but amazingly, fails to find any significant impacts by using probabilistic methods. However, regardless of the estimated probability, when an accident occurs, the resulting impacts are highly significant. Further information regarding the Lac-Mégantic accident is provided in Attachment 2, "Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail."[76] This analysis demonstrates that the costs of crude-by-rail accidents/spills can be very large, and that a major unit train accident/spill could cost $1 billion or more for a single event. Such accidents are per se significant and must be addressed and mitigated in the DEIR.

As explained in Attachment 2, the Lac-Mégantic rail accident/spill will likely have costs on the order of $500 million to $1 billion excluding any civil or criminal damages. Costs/damages for a similar incident could have been substantially higher had it occurred in a more populated area, such as the San Francisco Bay Area or Los Angeles, areas through which the Project's similarly configured and loaded unit trains will pass. Lac-Mégantic is also relevant in that it shows how an accident involving highly flammable light crude (such as the Bakken crude) can have devastating

[76] This analysis was prepared by The Goodman Group, Ltd, a consulting firm specializing in energy and regulatory economics, on behalf of Oil Change International.

consequences even in a small town in terms of loss of human life and widespread explosion and fire damage to surrounding property. The DEIR failed to recognize this demonstrated significant impact, instead dismissing it with unsupported probability analyses.

2. Marshall, Michigan

Attachment 2 also analyzes the spill of tar sands DilBit from Enbridge's Line 6B in Marshall, Michigan: This rupture in 2010 had costs of about $1 billion for Enbridge. The spill volumes at Marshall (840,000 gallons) were within the range of the amount of spill possible for ~~this Project (and, in fact, subst~~antially less than the maximum spill) if a crude by rail unit train released much of its cargo. Costs/damages for similar incidents within California could be substantially higher if it occurred in a more populated area, such as the Bay Area or Los Angeles. Marshall is also relevant in showing the high potential cost of dilbit spills into water (and rail lines are often very close to water, e.g., along the Sacramento River and within the Sacramento-San Joaquin Delta, the water supply for most of California's agriculture and drinking water).

3. Alabama

On November 8, 2013, a 90-car unit train carrying 2.7 million gallons of Bakken crude oil in DOT-11 tank cars derailed and exploded in a rural wetland in western Alabama, spilling crude oil into the surrounding wetlands and igniting a fire that burned for several days.[77] No injuries resulted from the accident, but a similar accident in a more populated location would certainly have caused serious risk to public safety.

[77] 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.

Figure 8
Aerial photo of Alabama derailment and explosion (Reuters)

4. <u>Casselton, North Dakota</u>

On December 30, 2013, a similar explosion occurred in Casselton, North Dakota, causing a fiery accident resulting in the town being evacuated. The BNSF train was more than 100 cars, all DOT-111, and about a mile long, of which at least 10 cars were destroyed.[78] Several of the DOT-111 tank cars ruptured and released crude oil that ignited. The post-accident fire destroyed two locomotives and thermally damaged several additional tank cars causing violent, fiery eruptions. Dense, toxic smoke forced a temporary evacuation of the town. Apparently, another train carrying grain derailed first, causing the adjacent Bakken oil filled cars to derail,[79] thus highlighting the hazards associated with multiple trains using the same or adjacent tracks, as proposed by the Rail Spur Project. The coastal line, for example, carries passenger traffic along the Pacific coast. Thus, human life could be put at risk, rather than just a train carrying grain.

5. <u>New Brunswick, Canada</u>

On January 7, 2014, 17 cars in a 122-unit train derailed and exploded near Plaster Rock, New Brunswick. No one was injured, but about 150 people were evacuated. The petroleum products originated in Western Canada and were destined for the Irving Oil Refinery in St. John.[80]

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[78] DOT-111 Tank Car, Wikipedia.
[79] NTSB, Staff Recommendation R-14-01 - 03, January 23, 2014.
[80] DOT-111 Tank Car, Wikipedia.

c. The DEIR Fails To Evaluate Crude By Rail As A Security Risk

The explosions in Lac-Mégantic and Alabama were accidents, but they could easily have been created by terrorists. The fact that terrorists haven't yet targeted rail tank cars carrying crude oil doesn't mean it won't occur in the future. The recent Canadian accidents demonstrate the amount of death and destruction that can happen if a rail tank car overturns. Terrorists will have read about these accidents. Without any additional security precautions, crude oil tank cars will be seen as a soft target for an attack, particularly, since they are often manned by small crews and often left unattended.

d. Off-Site Train Accident Analysis Unsupported

The results of the off-site train accident analysis appears full blown in Table 4.7-12 for a 72.6 mile segment of rail line from Highway 101 to Nipomo, broken into small segments. This table is apparently the basis of Figure 4.7-5, which presents the frequency of injuries and fatalities as a function of the number of each. Both of these summary results are presented with no supporting analysis, equations, citations, or explanatory material. Table 4.7-12 is also presented in Appendix H at H-19 and H-20, again with no supporting analysis, equation, citations, or explanatory material.

The DEIR asserts this analysis was prepared following guidelines of the American Institute of Chemical Engineers, Center for Chemical Process Safety (CCPS, 1995) and the parameters discussed in DEIR Section 4.7.1.3. DEIR, p. 4.7-61. However, I am very familiar with these guidelines and have used them in many similar analyses. I cannot follow or verify the risk analyses in DEIR Sec. 4.7. The following bulleted items list the columns in Table 4.7.12 and their support or lack thereof based on my review of the DEIR:

- Accident Probability (year): **no support**
- Probability Density: Table 4.7.6 ("default population densities")
- # of Trains per year: DEIR, pp. ES-3, 1-4
- Ignition: All Spill Probability (per year): **no support**
- Ignition: Small Spill Probability (per year): **no support**
- Ignition: Large Spill Probability (per year): **no support**
- No Ignition: All Spill Probability (per year): **no support**
- No Ignition: Small Spill Probability (per year): **no support**
- No Ignition: Large Spill Probability (per year): **no support**

The calculations and inputs to arrive at Table 4.7.12 are many and complex and MUST be included in an appendix to the DEIR, to the same level of detail as Appendix B for air emission calculations. The methods and inputs include, for example, the following types of standard calculations and inputs, none of which are disclosed in the DEIR:

> To evaluate whether a train accident is significant, one must estimate two numbers: 1) the probability that a consequence (e.g., injury or fatality) will occur from the accident and 2) the number of individuals that will be affected.
>
> These two numbers are usually calculated using standard procedures described in the Guidelines for Chemical Transportation Risk Analysis (CCPS, 1995). The first number, the probability that an incident outcome (i.e., a fatality or injury) will occur is given by:
>
> $$F_{g,i,k} = T \cdot A \cdot R_i \cdot L_g \cdot P_{i,k} \qquad (1)$$
>
> where:
>
> $F_{g,i,k}$ = frequency of incident outcome *k* for release size *i* on segment *g*
> T = trips per year
> A = accident rate per mile
> R_i = release probability for release size *i*
> L_g = length of segment *g* in miles
> $P_{i,k}$ = probability of incident outcome *k* for release size *i*
> *g* = segment counter
> *i* = release size counter
> *k* = incident outcome counter
>
> The second number, the associated consequences or number of persons exposed, is given by:
>
> $$N_{g,i,k} = CA_{i,k} \cdot PD_g \cdot PF_{i,k} \qquad (2)$$
>
> where:
>
> $N_{g,i,k}$ = number of fatalities (or injuries) for incident outcome *k* for release size *i* on segment *g*
> $CA_{I,k}$ = consequence area associated with incident outcome *k* for release size *i*
> PD_g = population density for segment *g*
> $PF_{I,k}$ = probability of injury/fatality for incident outcome *k* for release size *i*
> *g* = segment counter
> *i* = release size counter
> *k* = incident outcome counter

Without the type of information used in the above equations, the DEIR's train accident analysis is wholly unsupported. The DEIR must be revised to reveal and support all of the input assumptions represented by the variables used in these equations. The revised DEIR must be recirculated.

The unsupported information in Table 4.7.12 was then used to create injury and fatality risk charts that plot the frequency of accidents per year versus the number of injuries and fatalities in Figure 4.7-5. These are compared with Santa Barbara risk thresholds. There is no explanation for how the unsupported probability data from Table 4.7.6 was used to generate these risk curves. A complex series of calculations and various assumptions are typically involved, but none of these were disclosed in the DEIR, preventing public review. The DEIR must be expanded to support this analysis and recirculated to give the public an opportunity for input.

e. Entire Route In California Not Analyzed

The train accident analysis fails to analyze the risk of accident along the entire route within California, but rather stops at the northern San Luis Obispo County border and assumes no trains arrive or depart from the south. The DEIR indicates that unit trains will travel 68 miles[81] one-way within San Luis Obispo County and an additional 390 miles one-way outside of the County. DEIR, p. 4.3-42. Thus, the DEIR only analyzed the risk of train accidents for 17% of the route. This significantly understates the risk and consequences of train accidents as the County is sparsely populated. The projected rail route passes through some of the most densely populated areas with some of the most valuable real estate in the United States.

The DEIR fails to include a map that shows the route(s) that Project trains would follow. However, it does disclose that Union Pacific would be the carrier and includes a map of Union Pacific rail lines in California. DEIR, Fig. 4.12-2. This map indicates that trains may pass through some of the most densely populated areas in the United States, exposing some of the most sensitive and vulnerable public resources to significant adverse impacts.

The DEIR suggests that unit trains would most likely enter the northern part of the state, follow the rail line along the Sacramento River to Roseville, through Sacramento, Oakland, Santa Clara, San Jose, and down the coastal line to the Refinery. DEIR, p. 4.12-7 & Fig. 4.12-2. However, elsewhere, the DEIR indicates that trains could arrive from the north or the south (DEIR, p. 2-21), thus also passing through the densely populated Los Angeles area.

Unit trains approaching from the north would parallel the water supply for most of California, the Sacramento River and the Sacramento-San Joaquin Delta, and pass through some of the most densely populated areas and most valuable real estate in the world in the San Francisco Bay Area and Silicon Valley. An accident on the Mulford line between Santa Clara and Oakland or in San Jose, for example, which the DEIR indicates would be used (DEIR, p. 4.12-7), could have catastrophic effects on infrastructure, workers, and residents. As discussed elsewhere, the DEIR should have considered an alternate route, down the eastern side of the Central Valley, with a new connecting rail spur from Bakersfield to the Refinery, to avoid these significant impacts.

The federal preemption arguments in the DEIR do not prevent the County from requiring mitigation for significant impacts that occur on private land. Further, there is no preemption of the County's authority to refuse to issue a land use permit if Phillips 66 does not mitigate significant impacts that occur anywhere within California.

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[81] Elsewhere, the DEIR reports 72.6 miles within SLOC. DEIR, Table 4.7-12.

f. Track and Rail Car Condition Not Addressed

Unit trains loaded with up to 2.2 million gallons of crude oil (DEIR, p. 2-21) will travel one way over about 460 miles of rail line within California nearly every day. DEIR, p. 4.3-42. These trains can weigh up to 15,000 tons and extend for well over a mile. Rail accidents are the result of either an error on the part of the railroad operating personnel or a technical failure in the track, tank car design, and train control equipment. DEIR, p. 4.7-25, CCSP 1995, p. 64. The latter two can be anticipated and mitigated. The primary contributing factors to rail accidents that could have and should have been evaluated in the DEIR are track conditions, train speed, and railcar design.

Derailment rates are high on low class track and reduce rapidly as track quality improves. Broken rail is the factor most likely to pose the greatest risk to train operations as accidents due to broken rails are more frequent and more severe than average. They have been the cause of major derailments involving dangerous goods in both the U.S. and Canada.[82]

The DEIR made no attempt to assess track quality for the mainline route within California that would be used by unit trains. Rather, it dismisses the issue by stating that: "[m]ainline track is generally Class 5 or 6..." DEIR, p. 4.7-25. "Generally"? Is this true, especially along sections currently with light unit train traffic, such as coastal line? The DEIR is silent on track condition, which is a serious oversight. A survey could have and should have been conducted as an input to the risk of upset analysis and to evaluate alternate routes to mitigate impacts.

The severity and consequences of a derailment are related to speed because the energy dissipated during a derailment depends on the kinetic energy of the train, thus its speed and mass. Federal Railroad Administration data for mainline freight trains shows the number of cars derailed, an indicator of accident severity, is highly correlated with speed. Thus, speed reduction has the potential to reduce the severity and consequences of derailments.[83] The DEIR did not consider speed reduction.

Another key factor that affects both the probability and consequences of train accidents is the design and condition of the tank cars. CCSP 1995. The DEIR suggests that DOT-111 rail cars would be used. However, while the DEIR recognizes safety issues with these cars (see, e.g., p. 4.7-17, and 4.7-25) and explicitly recognizes that only about 25% of the current fleet has been upgraded to NTSB standards, it does not consider these flaws in its analyses and does nothing to assure that the Project will use the safest cars available that meet the most current safety standards. DEIR, p. 4.7-25. The DEIR

[82] Transportation Safety Board of Canada, Rail Recommendations R14-01, R14-02, R14-03, January 23, 2014, Available at: http://www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.asp#appx-a.

[83] C.P.L. Barkan, C.T. Dick and R. Anderson, Analysis of Railroad Derailment Factors Affecting Hazardous Materials Transportation Risk, Transportation Research Board Annual Meeting, 2003.

does not require any specific railcars nor safety standards for the rail cars that would be used in Project unit trains.

This is a serious flaw as it is widely acknowledged that the existing fleet of DOT-111 tank cars is unsafe for transporting crude oil or other hazardous materials. There are about 228,000 Class 111 tank cars currently in service in North America. Among many other deficiencies, the head and shells of DOT-111s are paper thin, and they lack many other vital safety features, such as head shields and protection for top fittings. As explained by the Transportation Safety Board of Canada (TSBC): "Many Class 111 tank cars do not have top fitting protection, head shields or thermal protection, and are not jacketed. The sides and heads of these tank cars are typically constructed with 7/16-inch-thick steel plate, which is thinner than some other classes of tank cars. When involved in accidents, these Class 111 tank cars are vulnerable to head and shell damage due to impacts, as well as fitting damage, which can result in the release of product. Furthermore, without thermal protection, additional product can be released through excessive venting of the safety relief device(s), or worse, through a thermal tear, which can result in complete product loss."[84]

Figure 9
Class 111 Tank Cars
Assumed in DEIR to Transport Crude (TSBC)

Rail tank cars should be able to withstand "rollover" accidents. But when pre-2011 DOT-111s are involved in accidents, even at low speeds, almost all of the tank cars rupture and release their contents. This was documented by the National Transportation Safety Board ("NTSB") in its "Cherry Valley accident report," cited in the Advanced Notice of Proposed Rulemaking for Hazardous Materials: Rail Petitions and Recommendations to Improve the Safety of Railroad Tank Car Transportation.[85] In that

[84] Transportation Safety Board of Canada, Rail Recommendation R14-01, R14-02, R14-03, January 23, 2014, Available at: http://www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.asp.

[85] PHMSA-2012-0082 (HM-251), 78 FR 54,849 (Sept. 6, 2013).

low-speed accident (36 mph), 13 of 15 tank cars ruptured. The NTSB noted that similar disastrous failure rates had been observed in other accidents (New Brighton, PA – 12 of 23 cars were breached; Arcadia, OH – 28 of 32 were breached).

The Cenovus Material Safety Data Sheet (MSDS) for Bakken crudes rates its flammability at Level 4, which is the highest rating, the same as for methane and propane gases. Under Canadian regulations, propane must be carried in DOT-112 or DOT-114 tank cars, but not in the U.S. Thus, while the use of DOT-111 tank cars would be illegal in Canada, they could be used in the U.S. where Bakken crudes originates[86] and appear to be approved by the DEIR for use on this Project. After the Lac- Mégantic accident in Canada, the Canadian government proposed to reclassify crude oil as a highly hazardous material, upgrading its classification from flammable and non-explosive.[87] The DEIR is seriously deficient for failing to call out this significant risk, the use of unsafe railcars to import highly flammable Bakken crudes through densely populated areas to the Refinery in "virtual pipelines". This is reckless.

C. Mitigation Is Inadequate

The DEIR does not impose any mitigation for accidents involving the import and storage of a new crude slate as it alleges there are no significant impacts. (Crossbucks will be installed at all railroad spur crossing with the Refinery. DEIR, p. IST-37.) However, as I demonstrate above, this conclusion is wrong. The import of a new slate of crudes by rail will result in many significant impacts. These must be mitigated. The following sections discuss some of the mitigation measures that I recommend.

Notably, on January 23, 2014, the National Transportation Safety Board (NTSB)[88] issued a series of recommendations to the Department of Transportation to address the safety risk of transporting crude oil by rail.[89] In an unprecedented move, the NTSB issued these recommendation in coordination with the Transportation Safety Board of Canada. [90] These recommendations include tougher standards for all Classs-111

[86] DOT-111 Tank Car, Wikipedia.

[87] Canada Orders Reinforced Fuel Trains After Disaster, January 10, 2014, Available at: http://crooksandliars.com/2014/01/canada-orders-reinforced-fuel-trains-after.

[88] NTSB Calls for Tougher Standards on Trains Carrying Crude Oil, January 23, 2014, Available at: http://www.ntsb.gov/news/2014/140123.html; FuelFix, Wreck Investigators Urge Tighter Rules for Oil Trains, January 23, 2014, Available at: http://fuelfix.com/blog/2014/01/23/rail-wreck-investigators-urge-tighter-rules-for-oil-trains/; The Globe and Mail, Canadian and U.S. Safety Watchdogs Warn of Oil-by-Rail's Risks in Push for Tighter Rules, January 23, 2014, Available at: http://www.theglobeandmail.com/news/politics/new-federal-rail-safety-proposal-to-tighten-scrutiny-of-crude-shipments/article16461771/#dashboard/follows/.

[89] NTSF, Safety Recommendation Letter R-14-001-003, January 23, 2014, Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-001-003.pdf and NTSB Safety Recommendation Letter R-14-004-006, January 21, 2014, Available at: http://www.ntsb.gov/doclib/recletters/2014/R-14-004-006.pdf.

[90] TSB and NTSB Call on Canadian and U.S. Regulators to Improve the Safe Transportation of Crude by Rail, Available at: http://www.tsb.gc.ca/eng/medias-media/communiques/rail/2014/r13d0054-

tank cars, not just new ones; strategic route planning; and emergency response assistance plans along routes where large volume of liquid hydrocarbons are shipped. All of these recommendations should be included as mitigation for the Rail Spur Project.

1. Community Emergency Preparedness Response

When a crude oil spill occurs, local response assets are generally the first ones on scene. These assets will include those provided by police departments, fire fighters, and emergency managers. Many times however, these response individuals are unaware of the nature of, and the threat posed by the materials that are being transported through their communities.

The public services and utilities section of the DEIR (Sec. 4.11), does not address how a local train accident would be handled. The DEIR concedes elsewhere that "In the unlikely event of an oil spill along the UPRR mainline tracks, there would likely be no oil spill containment or cleanup equipment available, and it would likely take some time for emergency response teams to mobilize adequate spill response equipment. Depending upon the location of the spill this could allow enough time for the spill to impact sensitive habitat and plants and animal species." DEIR, p. ES-7. Elsewhere the DEIR admits that "[o]peration of the Rail Spur Project could increase demand for fire protection and emergency response services." DEIR, pp. ES-9.

The only mitigation proposed for these deficiencies is implementation of a "Fire Protection Plan, Emergency Response Plan, Spill Prevention Control and Countermeasure Plan, training requirement for CALFIRE and the SMR fire brigade" within the Refinery. DEIR, pp. ES-9, IST-33. This is not adequate to address accidents along the 458 miles of track within California as it effectively places the burden of remediating the environmental consequences of an accident on local communities along the route. The DEIR failed to evaluate any alternatives to this do-nothing approach. The applicant could require its carrier to develop a comprehensive plan to ensure the availability of necessary response resources, including identifying and contracting the personnel and equipment necessary to respond to accidents along the route.

Congress, recognizing a gap in communication, mandated in the "9/11 Act"[91] that rail companies transporting security sensitive materials, including toxic-by-inhalation materials, but not including crude oil, improve communication with local officials. Rail carriers are now required to identify a point of contact and to provide information to (1) state and/or regional "Fusion Centers" that have been established to coordinate with state, local and tribal officials on security issues and which are located within the area encompassed by the rail carrier's rail system; and (2) state, local, and tribal officials in jurisdictions that may be affected by a rail carrier's routing decisions

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20140123.asp; See also: Rail Recommendations R14-01, R14-02, R14-03 at http://www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.asp and Backgrounder at http://www.tsb.gc.ca/eng/medias-media/fiches-facts/r13d0054/r13d0054-20140123.asp.

[91] Implementing Recommendations of the 9/11 Commission Act of 2007, Pub. L. 110-53; 121 Stat. 266.

and who directly contact the railroad to discuss routing decisions.[92] This knowledge enables local communities to have a better understanding of what is being transported near their homes and schools.

According to the mandate of the 9/11 Act, rail carriers transporting security sensitive materials are required to select lower-risk routes, based on an analysis of the safety and security risks presented various routes, railroad storage facilities and proximity of high-consequence targets along the route. The results of this analysis could dictate the rerouting of the security sensitive materials to other locations

Crude oil is not currently defined as "security sensitive" so the additional reporting requirement does not apply to rail carriers transporting crude oil, despite its obvious hazards. However, the DEIR should find the subject crudes as "security sensitive" and implement 9/11 Act requirements.

The lack of regulatory guidance on communication about the movement of crude oil via rail with local officials, neighbors and local businesses is inconsistent with the Administration's initiatives goal to improve preparedness. President Obama issued a proclamation on August 30, 2013 stating that September 2013 was National Preparedness Month. In this document, the President also stated that Americans should "refocus our efforts on readying ourselves, our families, our neighborhoods, and our Nation for any crisis we may face." Additionally he directed the Federal Emergency Management Agency to "launch a comprehensive campaign to build and sustain national preparedness with private sector, non-profit, and community leaders and all levels of government."[93] Private sector and community preparedness can't occur if the federal government fails to require the disclosure of information that could help communities become more prepared.

The failure to share information also contradicts the mission of the Citizen Corps, a FEMA-managed initiative. Its mission "is to harness the power of every individual through education, training, and volunteer service to make communities safer, stronger, and better prepared to respond to the threats of terrorism, crime, public health issues, and disasters of all kinds." http://www.ready.gov/citizen-corps. Disasters of all kinds include spills created by overturned rail tank cars carrying crude oil.

FEMA released a report on the Citizen Corps in September 2012. In this document entitled "Citizen Corps Councils Registration and Profile Data FY2011 National Report," FEMA Administrator Fugate stated that the Citizen Corps Councils provide '"the table"' for collaboration to "(i)ntegrate whole community representatives with emergency managers to ensure disaster preparedness and response planning represents the whole community and integrates nontraditional resources."[94] Again,

[92] http://www.gpo.gov/fdsys/pkg/FR-2008-11-26/html/E8-27826.htm.

[93] http://community.fema.gov/gf2.ti/f/280514/8233733.1/PDF/-/Presidential_Proclamation__National_Preparedness_Month_2013.pdf.

[94] FEMA, "Citizen Corps Councils Registration and Profile Data FY2011 National Report,"

without access to accurate information, the whole community is unable to adequately plan and integrate resources for disaster response and preparedness in line with FEMA objectives.

Finally, the failure to share information also contradicts recommendations provided by former Director of EPA's Office of Emergency Management Deborah Dietrich regarding coordination between the Citizen Corps and Local Emergency Planning Committees (LEPCs). Ms. Dietrich sent an August 2009 letter to all State Emergency Response Commission (SERC) Chairs recommending that all LEPCs work more closely with the Citizen Corps regarding the Emergency Planning and Community Right to Know Act of 1986 (EPCRA). She told them to consider "whether working more closely with the Citizen Corps could make your EPCRA and RMP work more effective."[95] Without basic knowledge about crude oil moving through their communities by rail, these planning committees are unable to accomplish their intended goal.

2. Rail Car Design

The DEIR suggests that DOT-111 non-pressurized tank cars would be used. DEIR, p. 4.7-25. However, as documented above, based on recent accidents and various proposed rulemakings, these railcars are known to pose significant risks when used to transport crude oil in unit trains.

Railcars are typically (99%) owned by the refiner, a leasing company, or a midstream producer, rather than the railroads.[96] Thus, there is no pre-emption issue and Phillips 66 has control over its railcars. The County can and should establish standards that the Project's railcars must meet. These standards should include the use of DOT-112 or DOT-114 when transporting Level 4 material such as Bakken and otherwise, the use of DOT-111 built to the most current standards, currently as of October 1, 2011, which include increased head and shell thickness; normalized steel; 1/2-inch thick head shield; and top fitting protection. DEIR, p. 4.7-25.

3. Train Staffing

A unit train carrying crude oil can weigh up to 15,000 tons and extend for up to a mile in length. Directing such a vehicle from point of origin to its destination is an inordinately demanding task, especially given the enormous risks involved if a mistake is made.

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https://s3-us-gov-west-1.amazonaws.com/dam-production/uploads/20130726-1854-25045-2121/citizen_corps_councils_final_report_9_27_2012.pdf, September 2012.

[95] Dietrich, Deborah, Letter to SERC Chairpersons, ftp://tbrpc.org/dri/Documents/LEPC/MISCELLANEOUS/EPA's%20EPCRA%20Letter.pdf. August 20, 2009.

[96] AAR, Moving Crude by Rail, May 2013, p. 9.

The range of tasks and responsibilities imposed on train staff includes powering up, maintaining speed (in compliance with ever-changing speed limits, changing grades, and track conditions), constant visual surveillance of the track and traffic control signals, continuously operating the radio, completing required paperwork, and remaining aware of other rail traffic.

Further, FRA rules require that each car in a hazmat train be inspected visually for defects, signs of tampering, and/or the presence of improvised explosive devices. 49 CFR 174.9(b). This could require over a mile of visual tank car inspections, thus requiring a solo staffer to be away from the locomotive for long periods.

In the event of derailment, collision, mechanical breakdown, etc, a massive piece of equipment such as a unit train cannot be safely operated by one individual. Redundancy in staffing is required to maintain safe operations. This has been recognized by the Federal Aviation Administration, which requires two pilots for all commercial flights. Crude unit trains should be subject to the same requirement.

Thus, the DEIR should include a condition requiring that Phillips 66 negotiate a contract with UPRR that requires at least two operators on each unit train carrying crude oil.

4. Alternate Route Should Be Required

The DEIR should have analyzed the safety and security risks of alternate transportation routes, including consideration of the crude volumes; track type, class, and maintenance schedule; track grade and curvature; environmentally sensitive or significant areas; population density along the routes; emergency response capability along the routes; passenger traffic along the route(s) (i.e., shared track); railway infrastructure (e.g., signaling, track class, crossings, wayside systems, traffic density); geography; and areas of high consequence as defined in 49 CFR 172.820(c). Based on this analysis, the DEIR should have selected the route posing the least overall safety and security risk.

In particular, the DEIR should have selected a route to prevent catastrophic release or explosion in proximity to densely populated areas, including urban areas and events or venues with large numbers of people in attendance, iconic buildings, landmarks, or environmentally sensitive areas.[97] The route selected in the DEIR (without any analysis or justification at all) violates every tenant of safety analysis. The proposed route passes through some of the most densely populated and environmentally sensitive areas in the world.

The coastal route selected in the DEIR overlaps with passenger routes and passes through some of the most densely populated areas in the United States. The Capitol Corridor line travels between San Jose and Sacramento. The Pacific Surfliner travels along the coast between San Luis Obispo and San Diego. The San Joaquin line runs

[97] 73 FR 20752 (April 16, 2008).

between Bakersfield and the San Francisco Bay Area. The California Zephyr runs between Emeryville and Chicago. The Coast Starlight run between Los Angeles and Chicago. DEIR, Sec. 4.12.

Further, the chosen route passes over 99 bridges and major road crossing in just San Luis Obispo County alone, of which only 33 are grade-separated crossings, where the railroad passes above or below the crossing. DEIR, p. 4.7-28. The DEIR failed to inventory bridges and crossing anywhere else. DEIR, Sec. 4.7 & 4.12. However, there are likely many in densely populated areas that unit trains will pass through. Many of these are likely unseparated and thus would increase the potential for accidents. DEIR, p. 4.7-28. As it could take over an hour for a unit train to pass through any given crossing, massive traffic jams could result in areas like the San Francisco Bay Area, Silicon Valley, and the greater Los Angeles area. The interaction of train traffic and rail traffic was not evaluated in the DEIR. Any increase in congestion due to this Project would be a significant impact that was not analyzed or mitigated.

The 9/11 Act, generally used to argue for safety of existing railroads, was enacted in 2007, when just 5,897 carloads of crude petroleum originated on U.S. Class I railroads. Last year, that number grew to 233,819 carloads – a growth of more than 3865%.[98] In 2013, that number has grown again, totaling 299,052 through the first 3 quarters (averaging about 100,000 per quarter). Assuming volumes will be similar in the fourth quarter, there will be about 400,000 carloads for all of 2013 – a growth of about 6700% relative to carloads in 2007.[99] This exponential growth in unit shipments of crude by rail and associated incidents, as well as the recent Lac-Mégantic disaster, compel the conclusion that unit shipments of crude oil demand enhanced safety standards and should be subjected to the re-routing standards as "security sensitive" materials as set forth in the 9/11 Act.

Finally, hybrid logistics, where crude is offloaded from rail at intermediate terminals, with transport via water and/or pipelines used for final delivery to the Refinery, should have been considered as alternatives to a 100% by rail delivery route. These are clearly on Phillip 66's[100] and other refiner's [101]plates.

5. Mitigation Is Deferred To The Future

The DEIR recommends several mitigation measures that would be developed in the future, outside of the CEQA review process. Thus should be fully developed as part of the DEIR to assure adequate public review.

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[98] AAR May 2013.

[99] AAR, August 29, 2013; AAR November 7, 2013.

[100] Phillips 66, Crude by Rail & Intermodal Supply Chain, Optimization and Opportunities, Refiner-Led Summit 2013, Opening Keynote Panel, August 21, 2013.

[101] Tesoro, Deutsche Bank Energy Conference, January 9, 2014.

First, prior to issuance of construction permits and notice to proceed, various fire protection and emergency response services would be developed including: "Fire Protection Plan, Emergency Response Plan, Spill Prevention Control and Countermeasure Plan, training requirement for CALFIRE and the SMR fire brigade." DEIR, pp. ES-9, IST-33. These updated plans should be included as appendices to the DEIR for public review.

Second, the Applicant also "shall investigate methods for reducing the onsite emissions, both from fugitive components and from locomotives" and "implement a program to limit onsite idling" prior to issuance of the Notice to Proceed, and thus outside of CEQA review. DEIR, p. IST-1.

VII. ALTERNATIVES

The DEIR considered five major alternatives to the Project: (1) truck transportation; (2) marine transportation; (3) alternative rail unloading sites; (4) loop rail unloading configuration; (5) reduced rail deliveries; (6) no project alternative. DEIR, Sec. 5.1. None of these alternatives significantly reduce impacts. Thus, they are not "alternatives" to the Project under CEQA.

The DEIR failed to evaluate other feasible alternatives that would have lesser impacts and more benefits. These include: (1) use of crude from the Price Canyon Oil Field Project Expansion, which proposes to increase local output,[102] to the extent available, rather than importing by rail; (2) continue production from existing or other nearby oil fields using enhanced oil recovery; (3) use of alternate rail route through the Central Valley with new connector rail line west from Bakersfield; (4) hybrid delivery options (e.g., partial delivery by sea or pipeline); (5) restrict crudes that can be imported.

The DEIR also failed to conduct any analysis at all of the no project alternative, rejecting it out of hand as it would not meet any of the project objectives. DEIR, p. 5-24. What are they? However, economic interests (at the expense of environmental impacts) is not a valid consideration under CEQA. When the no project alternative is the most environmentally superior then the next most environmentally preferred must be selected. DEIR, p. 5-33

The purpose of the Rail Spur Project, evidentially, is to reduce operating cost by importing cheaper oil. However, this should not be allowed at expense of the potentially catastrophic environment consequences, which are externalities that must be weighed, mitigated, or replaced when mitigations are not effective. Local sources of crude can be secured without the Rail Spur Project. New oil fields are currently being developed. The use of locally sourced crudes is the next most environmentally preferred.

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[102] Price Canyon Oilfield Project (Freeport McMoran Oil & Gas), Available at: http://www.slocounty.ca.gov/planning/environmental/EnvironmentalNotices/PXP.htm.

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Dr. Fox has over 40 years of experience in the field of environmental engineering, including air pollution control (BACT, BART, MACT, LAER, RACT), cost effectiveness analyses, air quality management, water quality and water supply investigations, hazardous waste investigations, environmental permitting, nuisance investigations (odor, noise), environmental impact reports, CEQA/NEPA documentation, risk assessments, and litigation support.

EDUCATION

Ph.D. Environmental/Civil Engineering, University of California, Berkeley, 1980.
M.S. Environmental/Civil Engineering, University of California, Berkeley, 1975.
B.S. Physics (with high honors), University of Florida, Gainesville, 1971.

REGISTRATION

Registered Professional Engineer: Arizona (2001-present: #36701), California (2002-present; CH 6058), Florida (2001-present; #57886), Georgia (2002-present; #PE027643), Washington (2002-present; #38692), Wisconsin (2005-present; #37595-006)
Board Certified Environmental Engineer, American Academy of Environmental Engineers, Certified in Air Pollution Control (DEE #01-20014), 2002-present
Qualified Environmental Professional (QEP), Institute of Professional Environmental Practice (QEP #02-010007), 2001-present

PROFESSIONAL HISTORY

Environmental Management, Principal, 1981-present
Lawrence Berkeley National Laboratory, Principal Investigator, 1977-1981
University of California, Berkeley, Program Manager, 1976-1977
Bechtel, Inc., Engineer, 1971-1976, 1964-1966

PROFESSIONAL AFFILIATIONS

American Chemical Society (1981-2010)
Phi Beta Kappa (1970-present)
Sigma Pi Sigma (1970-present)

Who's Who Environmental Registry, PH Publishing, Fort Collins, CO, 1992.
Who's Who in the World, Marquis Who's Who, Inc., Chicago, IL, 11th Ed., p. 371, 1993-present.
Who's Who of American Women, Marquis Who's Who, Inc., Chicago, IL, 13th Ed., p. 264, 1984-present.
Who's Who in Science and Engineering, Marquis Who's Who, Inc., New Providence, NJ, 5th Ed., p. 414, 1999-present.
Who’s Who in America, Marquis Who’s Who, Inc., 59th Ed., 2005.
Guide to Specialists on Toxic Substances, World Environment Center, New York, NY, p. 80, 1980.
National Research Council Committee on Irrigation-Induced Water Quality Problems (Selenium), Subcommittee on Quality Control/Quality Assurance (1985-1990).
National Research Council Committee on Surface Mining and Reclamation, Subcommittee on Oil Shale (1978-80)

REPRESENTATIVE EXPERIENCE

Performed environmental and engineering investigations, as outlined below, for a wide range of industrial and commercial facilities including: petroleum refineries and upgrades thereto; reformulated fuels projects; refinery upgrades to process heavy sour crudes, including tar sands and light sweet crudes from the Eagle Ford and Bakken Formations; petroleum distribution terminals; coal export terminals; LNG export, import, and storage terminals; shale oil plants; coal gasification & liquefaction plants; conventional and thermally enhanced oil production; underground storage tanks; pipelines; gasoline stations; landfills; railyards; hazardous waste treatment facilities; nuclear, hydroelectric, geothermal, wood, biomass, waste, tire-derived fuel, gas, oil, coke and coal-fired power plants; transmission lines; airports; hydrogen plants; petroleum coke calcining plants; coke plants; activated carbon manufacturing facilities; asphalt plants; cement plants; incinerators; flares; manufacturing facilities (e.g., semiconductors, electronic assembly, aerospace components, printed circuit boards, amusement park rides); lanthanide processing plants; ammonia plants; nitric acid plants; urea plants; food processing plants; almond hulling facilities; composting facilities; grain processing facilities; grain elevators; ethanol production facilities; soy bean oil extraction plants; biodiesel plants; paint formulation plants; wastewater treatment plants; marine terminals and ports; gas processing plants; steel mills; iron nugget production facilities; pig iron plant, based on blast furnace technology; direct reduced iron plant; acid regeneration facilities; railcar refinishing facility; battery manufacturing plants; pesticide manufacturing and repackaging facilities; pulp and paper mills; olefin plants; methanol plants; ethylene crackers; selective catalytic reduction (SCR) systems; selective noncatalytic reduction (SNCR) systems; halogen acid furnaces; contaminated property redevelopment projects (e.g., Mission Bay, Southern Pacific Railyards, Moscone Center expansion, San Diego Padres Ballpark); residential developments; commercial office parks, campuses, and shopping centers; server farms; transportation plans; and a wide range of mines including sand and gravel, hard rock, limestone, nacholite, coal, molybdenum, gold, zinc, and oil shale.

EXPERT WITNESS/LITIGATION SUPPORT

- For plaintiffs, expert witness in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1997-2000) at the Cemex cement plant in Lyons, Colorado. Reviewed produced documents, prepared expert and rebuttal reports on PSD applicability based on NOx emission calculations for a collection of changes considered both individually and collectively. Deposed August 2011. *United States v. Cemex, Inc.*, In U.S. District Court for the District of Colorado (Civil Action No. 09-cv-00019-MSK-MEH). Case settled June 13, 2013.
- For plaintiffs, in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1988 – 2000) at James De Young Units 3, 4, and 5. Reviewed produced documents, analyzed CEMS and EIA data, and prepared netting and BACT analyses for NOx, SO2, and PM10. Expert report February 24, 2010 and affidavit February 20, 2010. *Sierra Club v. City of Holland, et al.*, U.S. District Court, Western District of Michigan.
- For plaintiffs, in civil action alleging failure to obtain MACT permit, expert on potential to emit hydrogen chloride (HCl) from a new coal-fired boiler. Reviewed record, estimated HCl emissions, wrote expert report June 2010 and March 2013 (Cost to Install a Scrubber at the Lamar Repowering Project Pursuant to Case-by-Case MACT), deposed August 2010 and March 2013. *Wildearth Guardian et al. v. Lamar Utilities Board*, Civil Action No. 09-cv-02974, U.S. District Court, District of Colorado. Case settled August 2013.
- For plaintiffs, expert witness on permitting, emission calculations, and wastewater treatment for coal to gasoline plant. Reviewed produced documents. Assisted in preparation of comments on draft minor source permit. Wrote two affidavits on key issues in case. Presented direct and rebuttal testimony 10/27 - 10/28/10 on permit enforceability and failure to properly calculate potential to emit, including underestimate of flaring emissions and omission of VOC and CO emissions from wastewater treatment, cooling tower, tank roof landings, and malfunctions. *Sierra Club, Ohio Valley Environmental Coalition, Coal River Mountain Watch, West Virginia Highlands Conservancy v. John Benedict, Director, Division of Air Quality, West Virginia Department of Environmental Protection and TransGas Development System, LLC,* Appeal No. 10-01-AQB. Virginia Air Quality Board remanded the permit on March 28, 2011 ordering reconsideration of potential to emit calculations, including: (1) support for assumed flare efficiency; (2) inclusion of startup, shutdown and malfunction emissions; and (3) inclusion of wastewater treatment emissions in potential to emit calculations.

- For plaintiffs, expert on BACT emission limits for gas-fired combined cycle power plant. Prepared declaration in support of CBE's Opposition to the United States' Motion for Entry of Proposed Amended Consent Decree. Assisted in settlement discussions. *U.S. EPA, Plaintiff, Communities for a Better Environment, Intervenor Plaintiff, v. Pacific Gas & Electric Company, et al.*, U.S. District Court, Northern District of California, San Francisco Division, Case No. C-09-4503 SI.
- Technical expert in confidential settlement discussions with large coal-fired utility on BACT control technology and emission limits for NOx, SO2, PM, PM2.5, and CO for new natural gas fired combined cycle and simple cycle turbines with oil backup. (July 2010). Case settled.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1998-99) at Gallagher Units 1 and 3. Reviewed produced documents, prepared expert and rebuttal reports on historic and current-day BACT for SO2, control costs, and excess emissions of SO2. Deposed 11/18/09. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Settled 12/22/09.
- For plaintiffs, expert witness on MACT, BACT for NOx, and enforceability in an administrative appeal of draft state air permit issued for four 300-MW pet-coke-fired CFBs. Reviewed produced documents and prepared prefiled testimony. Deposed 10/8/09 and 11/9/09. Testified 11/10/09. *Application of Las Brisas Energy Center, LLC for State Air Quality Permit*; before the State Office of Administrative Hearings, Texas. Permit remanded 3/29/10 as LBEC failed to meet burden of proof on a number of issues including MACT. Texas Court of Appeals dismissed an appeal to reinstate the permit. The Texas Commission on Environmental Quality and Las Brisas Energy Center, LLC sought to overturn the Court of Appeals decision but moved to have their appeal dismissed in August 2013.
- For defense, expert witness in unlawful detainer case involving a gasoline station, minimart, and residential property with contamination from leaking underground storage tanks. Reviewed agency files and inspected site. Presented expert testimony on July 6, 2009, on causes of, nature and extent of subsurface contamination. *A. Singh v. S. Assaedi,* in Contra Costa County Superior Court, CA. Settled August 2009.
- For plaintiffs, expert witness on netting and enforceability for refinery being upgraded to process tar sands crude. Reviewed produced documents. Prepared expert and rebuttal reports addressing use of emission factors for baseline, omitted sources including coker, flares, tank landings and cleaning, and enforceability. Deposed. *In the Matter of Objection to the Issuance of Significant Source Modification Permit No. 089-25484-00453 to BP Products North America Inc., Whiting Business Unit, Save the Dunes Council, Inc., Sierra*

Club., Inc., Hoosier Environmental Council et al., Petitioners, B. P. Products North American, Respondents/Permittee, before the Indiana Office of Environmental Adjudication.

- For plaintiffs, expert witness on BACT, MACT, and enforceability in appeal of Title V permit issued to 600 MW coal-fired power plant burning Powder River Basin coal. Prepared technical comments on draft air permit. Reviewed record on appeal, drafted BACT, MACT, and enforceability pre-filed testimony. Drafted MACT and enforceability pre-filed rebuttal testimony. Deposed March 24, 2009. Testified June 10, 2009. *In Re: Southwestern Electric Power Company*, Arkansas Pollution Control and Ecology Commission, Consolidated Docket No. 08-006-P. Recommended Decision issued December 9, 2009 upholding issued permit. Commission adopted Recommended Decision January 22, 2010.

- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1989-1992) at Wabash Units 2, 3 and 5. Reviewed produced documents, prepared expert and rebuttal report on historic and current-day BACT for NOx and SO2, control costs, and excess emissions of NOx, SO2, and mercury. Deposed 10/21/08. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Testified 2/3/09. Memorandum Opinion & Order 5-29-09 requiring shutdown of Wabash River Units 2, 3, 5 by September 30, 2009, run at baseline until shutdown, and permanently surrender SO2 emission allowances.

- For plaintiffs, expert witness in liability phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for three historic modifications (1997-2001) at two portland cement plants involving three cement kilns. Reviewed produced documents, analyzed CEMS data covering subject period, prepared netting analysis for NOx, SO_2 and CO, and prepared expert and rebuttal reports. *United States v. Cemex California Cement,* In U.S. District Court for the Central District of California, Eastern Division, Case No. ED CV 07-00223-GW (JCRx), Settled 1/15/09.

- For intervenors Clean Wisconsin and Citizens Utility Board, prepared data requests, reviewed discovery and expert report. Prepared prefiled direct, rebuttal and surrebuttal testimony on cost to extend life of existing Oak Creek Units 5-8 and cost to address future regulatory requirements to determine whether to control or shutdown one or more of the units. Oral testimony 2/5/08. Application for a Certificate of Authority to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment for Control of Sulfur Dioxide and Nitrogen Oxide Emissions at Oak Creek Power Plant Units 5, 6, 7 and 8, WPSC Docket No. 6630-CE-299.

- For plaintiffs, expert witness on alternatives analysis and BACT for NOx, SO2, total PM10, and sulfuric acid mist in appeal of PSD permit issued to 1200 MW coal fired power plant burning Powder River Basin and/or Central Appalachian coal (Longleaf). Assisted in drafting technical comments on NOx on draft permit. Prepared expert disclosure. Presented 8+ days of direct and rebuttal expert testimony. Attended all 21 days of evidentiary hearing from 9/5/07 – 10/30/07 assisting in all aspects of hearing. *Friends of the Chatahooche and Sierra Club v. Dr. Carol Couch, Director, Environmental Protection Division of Natural Resources Department, Respondent, and Longleaf Energy Associates, Intervener*. ALJ Final Decision 1/11/08 denying petition. ALJ Order vacated & remanded for further proceedings, Fulton County Superior Court, 6/30/08. Court of Appeals of GA remanded the case with directions that the ALJ's final decision be vacated to consider the evidence under the correct standard of review, July 9, 2009. The ALJ issued an opinion April 2, 2010 in favor of the applicant. Final permit issued April 2010.

- For plaintiffs, expert witness on diesel exhaust in inverse condemnation case in which Port expanded maritime operations into residential neighborhoods, subjecting plaintiffs to noise, light, and diesel fumes. Measured real-time diesel particulate concentrations from marine vessels and tug boats on plaintiffs' property. Reviewed documents, depositions, DVDs, and photographs provided by counsel. Deposed. Testified October 24, 2006. *Ann Chargin, Richard Hackett, Carolyn Hackett, et al. v. Stockton Port District*, Superior Court of California, County of San Joaquin, Stockton Branch, No. CV021015. Judge ruled for plaintiffs.

- For plaintiffs, expert witness on NOx emissions and BACT in case alleging failure to obtain necessary permits and install controls on gas-fired combined-cycle turbines. Prepared and reviewed (applicant analyses) of NOx emissions, BACT analyses (water injection, SCR, ultra low NOx burners), and cost-effectiveness analyses based on site visit, plant operating records, stack tests, CEMS data, and turbine and catalyst vendor design information. Participated in negotiations to scope out consent order. *United States v. Nevada Power.* Case settled June 2007, resulting in installation of dry low NOx burners (5 ppm NOx averaged over 1 hr) on four units and a separate solar array at a local business.

- For plaintiffs, expert witness in appeal of PSD permit issued to 850 MW coal fired boiler burning Powder River Basin coal (Iatan Unit 2) on BACT for particulate matter, sulfuric acid mist and opacity and emission calculations for alleged historic violations of PSD. Assisted in drafting technical comments, petition for review, discovery requests, and responses to discovery requests. Reviewed produced documents. Prepared expert report on BACT for particulate matter. Assisted with expert depositions. Deposed February 7, 8, 27, 28, 2007. *In Re PSD Construction Permit Issued to Great Plains Energy, Kansas City Power & Light – Iatan Generating Station, Sierra Club v. Missouri Department of Natural Resources, Great Plains Energy, and Kansas City Power & Light.* Case settled March 27, 2007, providing offsets for over 6 million ton/yr of CO2 and lower NOx and SO_2 emission limits.

- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications of coal-fired boilers and associated equipment. Reviewed produced documents, prepared expert report on cost to retrofit 24 coal-fired power plants with scrubbers designed to remove 99%

of the sulfur dioxide from flue gases. Prepared supplemental and expert report on cost estimates and BACT for SO2 for these 24 complaint units. Deposed 1/30/07 and 3/14/07. *United States and State of New York et al. v. American Electric Power*, In U.S. District Court for the Southern District of Ohio, Eastern Division, Consolidated Civil Action Nos. C2-99-1182 and C2-99-1250. Settlement announced 10/9/07.

- For plaintiffs, expert witness on BACT, enforceability, and alternatives analysis in appeal of PSD permit issued for a 270-MW pulverized coal fired boiler burning Powder River Basin coal (City Utilities Springfield Unit 2). Reviewed permitting file and assisted counsel draft petition and prepare and respond to interrogatories and document requests. Reviewed interrogatory responses and produced documents. Assisted with expert depositions. Deposed August 2005. Evidentiary hearings October 2005. *In the Matter of Linda Chipperfield and Sierra Club v. Missouri Department of Natural Resources.* Missouri Supreme Court denied review of adverse lower court rulings August 2007.
- For plaintiffs, expert witness in civil action relating to plume touchdowns at AEP's Gavin coal-fired power plant. Assisted counsel draft interrogatories and document requests. Reviewed responses to interrogatories and produced documents. Prepared expert report "Releases of Sulfuric Acid Mist from the Gavin Power Station." The report evaluates sulfuric acid mist releases to determine if AEP complied with the requirements of CERCLA Section 103(a) and EPCRA Section 304. This report also discusses the formation, chemistry, release characteristics, and abatement of sulfuric acid mist in support of the claim that these releases present an imminent and substantial endangerment to public health under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"). *Citizens Against Pollution v. Ohio Power Company*, In the U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action No. 2-04-cv-371. Case settled 12-8-06.
- For petitioners, expert witness in contested case hearing on BACT, enforceability, and emission estimates for an air permit issued to a 500-MW supercritical Power River Basin coal-fired boiler (Weston Unit 4). Assisted counsel prepare comments on draft air permit and respond to and draft discovery. Reviewed produced file, deposed (7/05), and prepared expert report on BACT and enforceability. Evidentiary hearings September 2005. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin*, Case No. IH-04-21. The Final Order, issued 2/10/06, lowered the NOx BACT limit from 0.07 lb/MMBtu to 0.06 lb/MMBtu based on a 30-day average, added a BACT SO2 control efficiency, and required a 0.0005% high efficiency drift eliminator as BACT for the cooling tower. The modified permit, including these provisions, was issued 3/28/07. Additional appeals in progress.
- For plaintiffs, adviser on technical issues related to Citizen Suit against U.S. EPA regarding failure to update New Source Performance Standards for petroleum refineries, 40 CFR 60,

Subparts J, VV, and GGG. *Our Children's Earth Foundation and Sierra Club v. U.S. EPA et al.* Case settled July 2005. CD No. C 05-00094 CW, U.S. District Court, Northern District of California – Oakland Division. Proposed revisions to standards of performance for petroleum refineries published 72 FR 27178 (5/14/07).

- For interveners, reviewed proposed Consent Decree settling Clean Air Act violations due to historic modifications of boilers and associated equipment at two coal-fired power plants. In response to stay order, reviewed the record, selected one representative activity at each of seven generating units, and analyzed to identify CAA violations. Identified NSPS and NSR violations for NOx, SO_2, PM/PM10, and sulfuric acid mist. Summarized results in an expert report. *United States of America, and Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, Plaintiffs, and Clean Wisconsin, Sierra Club, and Citizens' Utility Board, Intervenors, v. Wisconsin Electric Power Company, Defendant*, U.S. District Court for the Eastern District of Wisconsin, Civil Action No. 2:03-CV-00371-CNC. Order issued 10-1-07 denying petition.
- For a coalition of Nevada labor organizations (ACE), reviewed preliminary determination to issue a Class I Air Quality Operating Permit to Construct and supporting files for a 250-MW pulverized coal-fired boiler (Newmont). Prepared about 100 pages of technical analyses and comments on BACT, MACT, emission calculations, and enforceability. Assisted counsel draft petition and reply brief appealing PSD permit to U.S. EPA Environmental Appeals Board (EAB). Order denying review issued 12/21/05. *In re Newmont Nevada Energy Investment, LLC, TS Power Plant*, PSD Appeal No. 05-04 (EAB 2005).
- For petitioners and plaintiffs, reviewed and prepared comments on air quality and hazardous waste based on negative declaration for refinery ultra low sulfur diesel project located in SCAQMD. Reviewed responses to comments and prepared responses. Prepared declaration and presented oral testimony before SCAQMD Hearing Board on exempt sources (cooling towers) and calculation of potential to emit under NSR. Petition for writ of mandate filed March 2005. Case remanded by Court of Appeals to trial court to direct SCAQMD to re-evaluate the potential environmental significance of NOx emissions resulting from the project in accordance with court's opinion. California Court of Appeals, Second Appellate Division, on December 18, 2007, affirmed in part (as to baseline) and denied in part. *Communities for a Better Environment v. South Coast Air Quality Management District and ConocoPhillips and Carlos Valdez et al v. South Coast Air Quality Management District and ConocoPhillips.* Certified for partial publication 1/16/08. Appellate Court opinion upheld by CA Supreme Court 3/15/10. *(2010) 48 Cal.4th 310*.
- For amici seeking to amend a proposed Consent Decree to settle alleged NSR violations at Chevron refineries, reviewed proposed settlement, related files, subject modifications, and emission calculations. Prepared declaration on emission reductions, identification of NSR and NSPS violations, and BACT/LAER for FCCUs, heaters and boilers, flares, and sulfur recovery plants. *U.S. et al. v. Chevron U.S.A.*, Northern District of California, Case No. C

03-04650. Memorandum and Order Entering Consent Decree issued June 2005. Case No. C 03-4650 CRB.

- For petitioners, prepared declaration on enforceability of periodic monitoring requirements, in response to EPA's revised interpretation of 40 CFR 70.6(c)(1). This revision limited additional monitoring required in Title V permits. 69 FR 3203 (Jan. 22, 2004). *Environmental Integrity Project et al. v. EPA* (U.S. Court of Appeals for the District of Columbia). Court ruled the Act requires all Title V permits to contain monitoring requirements to assure compliance. *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008).
- For interveners in application for authority to construct a 500 MW supercritical coal-fired generating unit before the Wisconsin Public Service Commission, prepared pre-filed written direct and rebuttal testimony with oral cross examination and rebuttal on BACT and MACT (Weston 4). Prepared written comments on BACT, MACT, and enforceability on draft air permit for same facility.
- For property owners in Nevada, evaluated the environmental impacts of a 1,450-MW coal-fired power plant proposed in a rural area adjacent to the Black Rock Desert and Granite Range, including emission calculations, air quality modeling, comments on proposed use permit to collect preconstruction monitoring data, and coordination with agencies and other interested parties. Project cancelled.
- For environmental organizations, reviewed draft PSD permit for a 600-MW coal-fired power plant in West Virginia (Longview). Prepared comments on permit enforceability; coal washing; BACT for SO_2 and PM10; Hg MACT; and MACT for HCl, HF, non-Hg metallic HAPs, and enforceability. Assist plaintiffs draft petition appealing air permit. Retained as expert to develop testimony on MACT, BACT, offsets, enforceability. Participate in settlement discussions. Case settled July 2004.
- For petitioners, reviewed record produced in discovery and prepared affidavit on emissions of carbon monoxide and volatile organic compounds during startup of GE 7FA combustion turbines to successfully establish plaintiff standing. *Sierra Club et al. v. Georgia Power Company* (Northern District of Georgia).
- For building trades, reviewed air quality permitting action for 1500-MW coal-fired power plant before the Kentucky Department for Environmental Protection (Thoroughbred).
- For petitioners, expert witness in administrative appeal of the PSD/Title V permit issued to a 1500-MW coal-fired power plant. Reviewed over 60,000 pages of produced documents, prepared discovery index, identified and assembled plaintiff exhibits. Deposed. Assisted counsel in drafting discovery requests, with over 30 depositions, witness cross examination, and brief drafting. Presented over 20 days of direct testimony, rebuttal and sur-rebuttal, with cross examination on BACT for NOx, SO_2, and PM/PM10; MACT for Hg and non-Hg metallic HAPs; emission estimates for purposes of Class I and II air modeling; risk assessment; and enforceability of permit limits. Evidentiary hearings from November 2003 to

June 2004. *Sierra Club et al. v. Natural Resources & Environmental Protection Cabinet, Division of Air Quality and Thoroughbred Generating Company et al.* Hearing Officer Decision issued August 9, 2005 finding in favor of plaintiffs on counts as to risk, BACT (IGCC/CFB, NOx, SO_2, Hg, Be), single source, enforceability, and errors and omissions. Assist counsel draft exceptions. Cabinet Secretary issued Order April 11, 2006 denying Hearing Offer's report, except as to NOx BACT, Hg, 99% SO2 control and certain errors and omissions.

- For citizens group in Massachusetts, reviewed, commented on, and participated in permitting of pollution control retrofits of coal-fired power plant (Salem Harbor).
- Assisted citizens group and labor union challenge issuance of conditional use permit for a 317,000 ft^2 discount store in Honolulu without any environmental review. In support of a motion for preliminary injunction, prepared 7-page declaration addressing public health impacts of diesel exhaust from vehicles serving the Project. In preparation for trial, prepared 20-page preliminary expert report summarizing results of diesel exhaust and noise measurements at two big box retail stores in Honolulu, estimated diesel PM10 concentrations for Project using ISCST, prepared a cancer health risk assessment based on these analyses, and evaluated noise impacts.
- Assisted environmental organizations to challenge the DOE Finding of No Significant Impact (FONSI) for the Baja California Power and Sempra Energy Resources Cross-Border Transmissions Lines in the U.S. and four associated power plants located in Mexico (DOE EA-1391). Prepared 20-page declaration in support of motion for summary judgment addressing emissions, including CO_2 and NH_3, offsets, BACT, cumulative air quality impacts, alternative cooling systems, and water use and water quality impacts. Plaintiff's motion for summary judgment granted in part. U.S. District Court, Southern District decision concluded that the Environmental Assessment and FONSI violated NEPA and the APA due to their inadequate analysis of the potential controversy surrounding the project, water impacts, impacts from NH_3 and CO_2, alternatives, and cumulative impacts. *Border Power Plant Working Group v. Department of Energy and Bureau of Land Management*, Case No. 02-CV-513-IEG (POR) (May 2, 2003).
- For Sacramento school, reviewed draft air permit issued for diesel generator located across from playfield. Prepared comments on emission estimates, enforceability, BACT, and health impacts of diesel exhaust. Case settled. BUG trap installed on the diesel generator.
- Assisted unions in appeal of Title V permit issued by BAAQMD to carbon plant that manufactured coke. Reviewed District files, identified historic modifications that should have triggered PSD review, and prepared technical comments on Title V permit. Reviewed responses to comments and assisted counsel draft appeal to BAAQMD hearing board, opening brief, motion to strike, and rebuttal brief. Case settled.
- Assisted California Central Coast city obtain controls on a proposed new city that would straddle the Ventura-Los Angeles County boundary. Reviewed several environmental impact reports, prepared an air quality analysis, a diesel exhaust health risk assessment, and

detailed review comments. Governor intervened and State dedicated the land for conservation purposes April 2004.

- Assisted Central California city to obtain controls on large alluvial sand quarry and asphalt plant proposing a modernization. Prepared comments on Negative Declaration on air quality, public health, noise, and traffic. Evaluated process flow diagrams and engineering reports to determine whether proposed changes increased plant capacity or substantially modified plant operations. Prepared comments on application for categorical exemption from CEQA. Presented testimony to County Board of Supervisors. Developed controls to mitigate impacts. Assisted counsel draft Petition for Writ. Case settled June 2002. Substantial improvements in plant operations were obtained including cap on throughput, dust control measures, asphalt plant loadout enclosure, and restrictions on truck routes.
- Assisted oil companies on the California Central Coast in defending class action citizen's lawsuit alleging health effects due to emissions from gas processing plant and leaking underground storage tanks. Reviewed regulatory and other files and advised counsel on merits of case. Case settled November 2001.
- Assisted oil company on the California Central Coast in defending property damage claims arising out of a historic oil spill. Reviewed site investigation reports, pump tests, leachability studies, and health risk assessments, participated in design of additional site characterization studies to assess health impacts, and advised counsel on merits of case. Prepare health risk assessment.
- Assisted unions in appeal of Initial Study/Negative Declaration ("IS/ND") for an MTBE phaseout project at a Bay Area refinery. Reviewed IS/ND and supporting agency permitting files and prepared technical comments on air quality, groundwater, and public health impacts. Reviewed responses to comments and final IS/ND and ATC permits and assisted counsel to draft petitions and briefs appealing decision to Air District Hearing Board. Presented sworn direct and rebuttal testimony with cross examination on groundwater impacts of ethanol spills on hydrocarbon contamination at refinery. Hearing Board ruled 5 to 0 in favor of appellants, remanding ATC to district to prepare an EIR.
- Assisted Florida cities in challenging the use of diesel and proposed BACT determinations in prevention of significant deterioration (PSD) permits issued to two 510-MW simple cycle peaking electric generating facilities and one 1,080-MW simple cycle/combined cycle facility. Reviewed permit applications, draft permits, and FDEP engineering evaluations, assisted counsel in drafting petitions and responding to discovery. Participated in settlement discussions. Cases settled or applications withdrawn.
- Assisted large California city in federal lawsuit alleging peaker power plant was violating its federal permit. Reviewed permit file and applicant's engineering and cost feasibility study to reduce emissions through retrofit controls. Advised counsel on feasible and cost-effective

NOx, SOx, and PM10 controls for several 1960s diesel-fired Pratt and Whitney peaker turbines. Case settled.

- Assisted coalition of Georgia environmental groups in evaluating BACT determinations and permit conditions in PSD permits issued to several large natural gas-fired simple cycle and combined-cycle power plants. Prepared technical comments on draft PSD permits on BACT, enforceability of limits, and toxic emissions. Reviewed responses to comments, advised counsel on merits of cases, participated in settlement discussions, presented oral and written testimony in adjudicatory hearings, and provided technical assistance as required. Cases settled or won at trial.
- Assisted construction unions in review of air quality permitting actions before the Indiana Department of Environmental Management ("IDEM") for several natural gas-fired simple cycle peaker and combined cycle power plants.
- Assisted coalition of towns and environmental groups in challenging air permits issued to 523 MW dual fuel (natural gas and distillate) combined-cycle power plant in Connecticut. Prepared technical comments on draft permits and 60 pages of written testimony addressing emission estimates, startup/shutdown issues, BACT/LAER analyses, and toxic air emissions. Presented testimony in adjudicatory administrative hearings before the Connecticut Department of Environmental Protection in June 2001 and December 2001.
- Assisted various coalitions of unions, citizens groups, cities, public agencies, and developers in licensing and permitting of over 110 coal, gas, oil, biomass, and pet coke-fired power plants generating over 75,000 MW of electricity. These included base-load, combined cycle, simple cycle, and peaker power plants in Alaska, Arizona, Arkansas, California, Colorado, Georgia, Florida, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Oklahoma, Oregon, Texas, West Virginia, Wisconsin, and elsewhere. Prepared analyses of and comments on applications for certification, preliminary and final staff assessments, and various air, water, wastewater, and solid waste permits issued by local agencies. Presented written and oral testimony before various administrative bodies on hazards of ammonia use and transportation, health effects of air emissions, contaminated property issues, BACT/LAER issues related to SCR and SCONOx, criteria and toxic pollutant emission estimates, MACT analyses, air quality modeling, water supply and water quality issues, and methods to reduce water use, including dry cooling, parallel dry-wet cooling, hybrid cooling, and zero liquid discharge systems.
- Assisted unions, cities, and neighborhood associations in challenging an EIR issued for the proposed expansion of the Oakland Airport. Reviewed two draft EIRs and prepared a health risk assessment and extensive technical comments on air quality and public health impacts. The California Court of Appeals, First Appellate District, ruled in favor of appellants and plaintiffs, concluding that the EIR "2) erred in using outdated information in assessing the emission of toxic air contaminants (TACs) from jet aircraft; 3) failed to support its decision

not to evaluate the health risks associated with the emission of TACs with meaningful analysis," thus accepting my technical arguments and requiring the Port to prepare a new EIR. See *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598.

- Assisted lessor of former gas station with leaking underground storage tanks and TCE contamination from adjacent property. Lessor held option to purchase, which was forfeited based on misrepresentation by remediation contractor as to nature and extent of contamination. Remediation contractor purchased property. Reviewed regulatory agency files and advised counsel on merits of case. Case not filed.
- Advised counsel on merits of several pending actions, including a Proposition 65 case involving groundwater contamination at an explosives manufacturing firm and two former gas stations with leaking underground storage tanks.
- Assisted defendant foundry in Oakland in a lawsuit brought by neighbors alleging property contamination, nuisance, trespass, smoke, and health effects from foundry operation. Inspected and sampled plaintiff's property. Advised counsel on merits of case. Case settled.
- Assisted business owner facing eminent domain eviction. Prepared technical comments on a negative declaration for soil contamination and public health risks from air emissions from a proposed redevelopment project in San Francisco in support of a CEQA lawsuit. Case settled.
- Assisted neighborhood association representing residents living downwind of a Berkeley asphalt plant in separate nuisance and CEQA lawsuits. Prepared technical comments on air quality, odor, and noise impacts, presented testimony at commission and council meetings, participated in community workshops, and participated in settlement discussions. Cases settled. Asphalt plant was upgraded to include air emission and noise controls, including vapor collection system at truck loading station, enclosures for noisy equipment, and improved housekeeping.
- Assisted a Fortune 500 residential home builder in claims alleging health effects from faulty installation of gas appliances. Conducted indoor air quality study, advised counsel on merits of case, and participated in discussions with plaintiffs. Case settled.
- Assisted property owners in Silicon Valley in lawsuit to recover remediation costs from insurer for large TCE plume originating from a manufacturing facility. Conducted investigations to demonstrate sudden and accidental release of TCE, including groundwater modeling, development of method to date spill, preparation of chemical inventory, investigation of historical waste disposal practices and standards, and on-site sewer and storm drainage inspections and sampling. Prepared declaration in opposition to motion for summary judgment. Case settled.

- Assisted residents in east Oakland downwind of a former battery plant in class action lawsuit alleging property contamination from lead emissions. Conducted historical research and dry deposition modeling that substantiated claim. Participated in mediation at JAMS. Case settled.
- Assisted property owners in West Oakland who purchased a former gas station that had leaking underground storage tanks and groundwater contamination. Reviewed agency files and advised counsel on merits of case. Prepared declaration in opposition to summary judgment. Prepared cost estimate to remediate site. Participated in settlement discussions. Case settled.
- Consultant to counsel representing plaintiffs in two Clean Water Act lawsuits involving selenium discharges into San Francisco Bay from refineries. Reviewed files and advised counsel on merits of case. Prepared interrogatory and discovery questions, assisted in deposing opposing experts, and reviewed and interpreted treatability and other technical studies. Judge ruled in favor of plaintiffs.
- Assisted oil company in a complaint filed by a resident of a small California beach community alleging that discharges of tank farm rinse water into the sanitary sewer system caused hydrogen sulfide gas to infiltrate residence, sending occupants to hospital. Inspected accident site, interviewed parties to the event, and reviewed extensive agency files related to incident. Used chemical analysis, field simulations, mass balance calculations, sewer hydraulic simulations with SWMM44, atmospheric dispersion modeling with SCREEN3, odor analyses, and risk assessment calculations to demonstrate that the incident was caused by a faulty drain trap and inadequate slope of sewer lateral on resident's property. Prepared a detailed technical report summarizing these studies. Case settled.
- Assisted large West Coast city in suit alleging that leaking underground storage tanks on city property had damaged the waterproofing on downgradient building, causing leaks in an underground parking structure. Reviewed subsurface hydrogeologic investigations and evaluated studies conducted by others documenting leakage from underground diesel and gasoline tanks. Inspected, tested, and evaluated waterproofing on subsurface parking structure. Waterproofing was substandard. Case settled.
- Assisted residents downwind of gravel mine and asphalt plant in Siskiyou County, California, in suit to obtain CEQA review of air permitting action. Prepared two declarations analyzing air quality and public health impacts. Judge ruled in favor of plaintiffs, closing mine and asphalt plant.
- Assisted defendant oil company on the California Central Coast in class action lawsuit alleging property damage and health effects from subsurface petroleum contamination. Reviewed documents, prepared risk calculations, and advised counsel on merits of case. Participated in settlement discussions. Case settled.

- Assisted defendant oil company in class action lawsuit alleging health impacts from remediation of petroleum contaminated site on California Central Coast. Reviewed documents, designed and conducted monitoring program, and participated in settlement discussions. Case settled.
- Consultant to attorneys representing irrigation districts and municipal water districts to evaluate a potential challenge of USFWS actions under CVPIA section 3406(b)(2). Reviewed agency files and collected and analyzed hydrology, water quality, and fishery data. Advised counsel on merits of case. Case not filed.
- Assisted residents downwind of a Carson refinery in class action lawsuit involving soil and groundwater contamination, nuisance, property damage, and health effects from air emissions. Reviewed files and provided advise on contaminated soil and groundwater, toxic emissions, and health risks. Prepared declaration on refinery fugitive emissions. Prepared deposition questions and reviewed deposition transcripts on air quality, soil contamination, odors, and health impacts. Case settled.
- Assisted residents downwind of a Contra Costa refinery who were affected by an accidental release of naphtha. Characterized spilled naphtha, estimated emissions, and modeled ambient concentrations of hydrocarbons and sulfur compounds. Deposed. Presented testimony in binding arbitration at JAMS. Judge found in favor of plaintiffs.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects from several large accidents as well as routine operations. Reviewed files and prepared analyses of environmental impacts. Prepared declarations, deposed, and presented testimony before jury in one trial and judge in second. Case settled.
- Assisted business owner claiming damages from dust, noise, and vibration during a sewer construction project in San Francisco. Reviewed agency files and PM10 monitoring data and advised counsel on merits of case. Case settled.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects. Prepared declaration in opposition to summary judgment, deposed, and presented expert testimony on accidental releases, odor, and nuisance before jury. Case thrown out by judge, but reversed on appeal and not retried.
- Presented testimony in small claims court on behalf of residents claiming health effects from hydrogen sulfide from flaring emissions triggered by a power outage at a Contra Costa County refinery. Analyzed meteorological and air quality data and evaluated potential health risks of exposure to low concentrations of hydrogen sulfide. Judge awarded damages to plaintiffs.
- Assisted construction unions in challenging PSD permit for an Indiana steel mill. Prepared technical comments on draft PSD permit, drafted 70-page appeal of agency permit action to

the Environmental Appeals Board challenging permit based on faulty BACT analysis for electric arc furnace and reheat furnace and faulty permit conditions, among others, and drafted briefs responding to four parties. EPA Region V and the EPA General Counsel intervened as amici, supporting petitioners. EAB ruled in favor of petitioners, remanding permit to IDEM on three key issues, including BACT for the reheat furnace and lead emissions from the EAF. Drafted motion to reconsider three issues. Prepared 69 pages of technical comments on revised draft PSD permit. Drafted second EAB appeal addressing lead emissions from the EAF and BACT for reheat furnace based on European experience with SCR/SNCR. Case settled. Permit was substantially improved. See *In re: Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5 (EAB June 22, 2000).

- Assisted defendant urea manufacturer in Alaska in negotiations with USEPA to seek relief from penalties for alleged violations of the Clean Air Act. Reviewed and evaluated regulatory files and monitoring data, prepared technical analysis demonstrating that permit limits were not violated, and participated in negotiations with EPA to dismiss action. Fines were substantially reduced and case closed.
- Assisted construction unions in challenging PSD permitting action for an Indiana grain mill. Prepared technical comments on draft PSD permit and assisted counsel draft appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analyses for heaters and boilers and faulty permit conditions, among others. Case settled.
- As part of a consent decree settling a CEQA lawsuit, assisted neighbors of a large west coast port in negotiations with port authority to secure mitigation for air quality impacts. Prepared technical comments on mobile source air quality impacts and mitigation and negotiated a $9 million CEQA mitigation package. Represented neighbors on technical advisory committee established by port to implement the air quality mitigation program. Program successfully implemented.
- Assisted construction unions in challenging permitting action for a California hazardous waste incinerator. Prepared technical comments on draft permit, assisted counsel prepare appeal of EPA permit to the Environmental Appeals Board. Participated in settlement discussions on technical issues with applicant and EPA Region 9. Case settled.
- Assisted environmental group in challenging DTSC Negative Declaration on a hazardous waste treatment facility. Prepared technical comments on risk of upset, water, and health risks. Writ of mandamus issued.
- Assisted several neighborhood associations and cities impacted by quarries, asphalt plants, and cement plants in Alameda, Shasta, Sonoma, and Mendocino counties in obtaining mitigations for dust, air quality, public health, traffic, and noise impacts from facility operations and proposed expansions.

- For over 100 industrial facilities, commercial/campus, and redevelopment projects, developed the record in preparation for CEQA and NEPA lawsuits. Prepared technical comments on hazardous materials, solid wastes, public utilities, noise, worker safety, air quality, public health, water resources, water quality, traffic, and risk of upset sections of EIRs, EISs, FONSIs, initial studies, and negative declarations. Assisted counsel in drafting petitions and briefs and prepared declarations.
- For several large commercial development projects and airports, assisted applicant and counsel prepare defensible CEQA documents, respond to comments, and identify and evaluate "all feasible" mitigation to avoid CEQA challenges. This work included developing mitigation programs to reduce traffic-related air quality impacts based on energy conservation programs, solar, low-emission vehicles, alternative fuels, exhaust treatments, and transportation management associations.

SITE INVESTIGATION/REMEDIATION/CLOSURE

- Technical manager and principal engineer for characterization, remediation, and closure of waste management units at former Colorado oil shale plant. Constituents of concern included BTEX, As, 1,1,1-TCA, and TPH. Completed groundwater monitoring programs, site assessments, work plans, and closure plans for seven process water holding ponds, a refinery sewer system, and processed shale disposal area. Managed design and construction of groundwater treatment system and removal actions and obtained clean closure.
- Principal engineer for characterization, remediation, and closure of process water ponds at a former lanthanide processing plant in Colorado. Designed and implemented groundwater monitoring program and site assessments and prepared closure plan.
- Advised the city of Sacramento on redevelopment of two former railyards. Reviewed work plans, site investigations, risk assessment, RAPS, RI/FSs, and CEQA documents. Participated in the development of mitigation strategies to protect construction and utility workers and the public during remediation, redevelopment, and use of the site, including buffer zones, subslab venting, rail berm containment structure, and an environmental oversight plan.
- Provided technical support for the investigation of a former sanitary landfill that was redeveloped as single family homes. Reviewed and/or prepared portions of numerous documents, including health risk assessments, preliminary endangerment assessments, site investigation reports, work plans, and RI/FSs. Historical research to identify historic waste disposal practices to prepare a preliminary endangerment assessment. Acquired, reviewed, and analyzed the files of 18 federal, state, and local agencies, three sets of construction field notes, analyzed 21 aerial photographs and interviewed 14 individuals associated with operation of former landfill. Assisted counsel in defending lawsuit brought by residents

alleging health impacts and diminution of property value due to residual contamination. Prepared summary reports.

- Technical oversight of characterization and remediation of a nitrate plume at an explosives manufacturing facility in Lincoln, CA. Provided interface between owners and consultants. Reviewed site assessments, work plans, closure plans, and RI/FSs.
- Consultant to owner of large western molybdenum mine proposed for NPL listing. Participated in negotiations to scope out consent order and develop scope of work. Participated in studies to determine premining groundwater background to evaluate applicability of water quality standards. Served on technical committees to develop alternatives to mitigate impacts and close the facility, including resloping and grading, various thickness and types of covers, and reclamation. This work included developing and evaluating methods to control surface runoff and erosion, mitigate impacts of acid rock drainage on surface and ground waters, and stabilize nine waste rock piles containing 328 million tons of pyrite-rich, mixed volcanic waste rock (andesites, rhyolite, tuff). Evaluated stability of waste rock piles. Represented client in hearings and meetings with state and federal oversight agencies.

REGULATORY (PARTIAL LIST)

- In July 2013, prepared technical report on fugitive particulate matter emissions from coal train staging at the proposed Coyote Island Terminal, Oregon, for draft Permit No. 25-0015-ST-01.
- In July 2013, prepared technical comments on air quality impacts of the Finger Lakes LPG Storage Facility as reported in various Environmental Impact Statements.
- In June 2013, prepared technical report on a Mitigated Negative Declaration for a new rail terminal at the Valero Benicia Refinery to import increased amounts of "North American" crudes in. Comments addressed air quality impacts of refining increased amounts of tar sands crudes.
- In May 2013, prepared comments on draft PSD permit for major expansion of midwest refinery to process 100% tar sands crudes, including a complex netting analysis involving debottlenecking and piecemealing and BACT analyses.
- In April 2013, prepared technical report on the Draft Supplemental Environmental Impact Statement (DSEIS) for the Keystone XL Pipeline on air quality impacts from refining increased amount of tar sands crudes at Refineries in PADD 3.
- In October 2012, prepared technical report on the Environmental Review for the Coyote Island Terminal Dock at the Port of Morrow on fugitive particulate matter emissions.

- Prepared cost analyses and comments on New York's proposed BART determinations for NOx, SO2, and PM and EPA's proposed approval of BART determinations for Danskammer Generating Station under New York Regional Haze State Implementation Plan and Federal Implementation Plan, 77 FR 51915 (August 28, 2012).
- Prepared cost analyses and comments on NOx BART determinations for Regional Haze State Implementation Plan for State of Nevada, 77 FR 23191 (April 18, 2012) and 77 FR 25660 (May 1, 2012).
- Prepared analyses of and comments on New Source Performance Standards for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392 (April 13, 2012).
- Prepared comments on CASPR-BART emission equivalency and NOx and PM BART determinations in EPA proposed approval of State Implementation Plan for Pennsylvania Regional Haze Implementation Plan, 77 FR 3984 (January 26, 2012).
- Prepared comments and statistical analyses on hazardous air pollutants (HAPs) emission controls, monitoring, compliance methods, and the use of surrogates for acid gases, organic HAPs, and metallic HAPs for proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 76 FR 24976 (May 3, 2011).
- Prepared cost analyses and comments on NOx BART determinations and emission reductions for proposed Federal Implementation Plan for Four Corners Power Plant, 75 FR 64221 (October 19, 2010).
- Prepared cost analyses and comments on NOx BART determinations for Colstrip Units 1- 4 for Montana State Implementation Plan and Regional Haze Federal Implementation Plan, 77 FR 23988 (April 20, 2010).
- For EPA Region 8, prepared report: Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, March 2011, in support of 76 FR 58570 (Sept. 21, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Selective Catalytic Reduction at the Public Service Company of New Mexico San Juan Generating Station, November 2010, in support of 76 FR 52388 (Aug. 22, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2, Muskogee Units 4 & 5, Northeastern Units 3 &4, October 2010, in support of 76 FR 16168 (March 26, 2011). My work was upheld in: *State of Oklahoma v. EPA*, App. Case 12-9526 (10th Cri. July 19, 2013).

- Identified errors in N_2O emission factors in the Mandatory Greenhouse Gas Reporting Rule, 40 CFR 98, and prepared technical analysis to support Petition for Rulemaking to Correct Emissions Factors in the Mandatory Greenhouse Gas Reporting Rule, filed with EPA on 10/28/10.
- Assist interested parties develop input for and prepare comments on the Information Collection Request for Petroleum Refinery Sector NSPS and NESHAP Residual Risk and Technology Review, 75 FR 60107 (9/29/10).
- Technical reviewer of EPA's "Emission Estimation Protocol for Petroleum Refineries," posted for public comments on CHIEF on 12/23/09, prepared in response to the City of Houston's petition under the Data Quality Act (March 2010).
- Prepared comments on SCR cost effectiveness for EPA's Advanced Notice of Proposed Rulemaking, Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station, 74 FR 44313 (August 28, 2009).
- Prepared comments on Proposed Rule for Standards of Performance for Coal Preparation and Processing Plants, 74 FR 25304 (May 27, 2009).
- Prepared comments on draft PSD permit for major expansion of midwest refinery to process up to 100% tar sands crudes. Participated in development of monitoring and controls to mitigate impacts and in negotiating a Consent Decree to settle claims in 2008.
- Reviewed and assisted interested parties prepare comments on proposed Kentucky air toxic regulations at 401 KAR 64:005, 64:010, 64:020, and 64:030 (June 2007).
- Prepared comments on proposed Standards of Performance for Electric Utility Steam Generating Units and Small Industrial-Commercial-Industrial Steam Generating Units, 70 FR 9706 (February 28, 2005).
- Prepared comments on Louisville Air Pollution Control District proposed Strategic Toxic Air Reduction regulations.
- Prepared comments and analysis of BAAQMD Regulation, Rule 11, Flare Monitoring at Petroleum Refineries.
- Prepared comments on Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electricity Utility Steam Generating Units (MACT standards for coal-fired power plants).
- Prepared Authority to Construct Permit for remediation of a large petroleum-contaminated site on the California Central Coast. Negotiated conditions with agencies and secured permits.

- Prepared Authority to Construct Permit for remediation of a former oil field on the California Central Coast. Participated in negotiations with agencies and secured permits.
- Prepared and/or reviewed hundreds of environmental permits, including NPDES, UIC, Stormwater, Authority to Construct, Prevention of Significant Deterioration, Nonattainment New Source Review, Title V, and RCRA, among others.
- Participated in the development of the CARB document, *Guidance for Power Plant Siting and Best Available Control Technology*, including attending public workshops and filing technical comments.
- Performed data analyses in support of adoption of emergency power restoration standards by the California Public Utilities Commission for "major" power outages, where major is an outage that simultaneously affects 10% of the customer base.
- Drafted portions of the Good Neighbor Ordinance to grant Contra Costa County greater authority over safety of local industry, particularly chemical plants and refineries.
- Participated in drafting BAAQMD Regulation 8, Rule 28, Pressure Relief Devices, including participation in public workshops, review of staff reports, draft rules and other technical materials, preparation of technical comments on staff proposals, research on availability and costs of methods to control PRV releases, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and cost of low-leak technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pumps and Compressors, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak and seal-less technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of controlling tank emissions, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors at Petroleum Refinery Complexes, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 22, Valves and Flanges at Chemical Plants, etc, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pump and Compressor Seals, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability of low-leak technology, and presentation of testimony before the Board.
- Participated in the development of the BAAQMD Regulation 2, Rule 5, Toxics, including participation in public workshops, review of staff proposals, and preparation of technical comments.
- Participated in the development of SCAQMD Rule 1402, Control of Toxic Air Contaminants from Existing Sources, and proposed amendments to Rule 1401, New Source Review of Toxic Air Contaminants, in 1993, including review of staff proposals and preparation of technical comments on same.
- Participated in the development of the Sunnyvale Ordinance to Regulate the Storage, Use and Handling of Toxic Gas, which was designed to provide engineering controls for gases that are not otherwise regulated by the Uniform Fire Code.
- Participated in the drafting of the Statewide Water Quality Control Plans for Inland Surface Waters and Enclosed Bays and Estuaries, including participation in workshops, review of draft plans, preparation of technical comments on draft plans, and presentation of testimony before the SWRCB.
- Participated in developing Se permit effluent limitations for the five Bay Area refineries, including review of staff proposals, statistical analyses of Se effluent data, review of literature on aquatic toxicity of Se, preparation of technical comments on several staff proposals, and presentation of testimony before the Bay Area RWQCB.
- Represented the California Department of Water Resources in the 1991 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on a striped bass model developed by the California Department of Fish and Game.
- Represented the State Water Contractors in the 1987 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on natural flows, historical salinity trends in San Francisco Bay, Delta outflow, and hydrodynamics of the South Bay.
- Represented interveners in the licensing of over 20 natural-gas-fired power plants and one coal gasification plant at the California Energy Commission and elsewhere. Reviewed and

prepared technical comments on applications for certification, preliminary staff assessments, final staff assessments, preliminary determinations of compliance, final determinations of compliance, and prevention of significant deterioration permits in the areas of air quality, water supply, water quality, biology, public health, worker safety, transportation, site contamination, cooling systems, and hazardous materials. Presented written and oral testimony in evidentiary hearings with cross examination and rebuttal. Participated in technical workshops.

- Represented several parties in the proposed merger of San Diego Gas & Electric and Southern California Edison. Prepared independent technical analyses on health risks, air quality, and water quality. Presented written and oral testimony before the Public Utilities Commission administrative law judge with cross examination and rebuttal.
- Represented a PRP in negotiations with local health and other agencies to establish impact of subsurface contamination on overlying residential properties. Reviewed health studies prepared by agency consultants and worked with agencies and their consultants to evaluate health risks.

WATER QUALITY/RESOURCES

- Directed and participated in research on environmental impacts of energy development in the Colorado River Basin, including contamination of surface and subsurface waters and modeling of flow and chemical transport through fractured aquifers.
- Played a major role in Northern California water resource planning studies since the early 1970s. Prepared portions of the Basin Plans for the Sacramento, San Joaquin, and Delta basins including sections on water supply, water quality, beneficial uses, waste load allocation, and agricultural drainage. Developed water quality models for the Sacramento and San Joaquin Rivers.
- Conducted hundreds of studies over the past 40 years on Delta water supplies and the impacts of exports from the Delta on water quality and biological resources of the Central Valley, Sacramento-San Joaquin Delta, and San Francisco Bay. Typical examples include:

    1. Evaluate historical trends in salinity, temperature, and flow in San Francisco Bay and upstream rivers to determine impacts of water exports on the estuary;
    2. Evaluate the role of exports and natural factors on the food web by exploring the relationship between salinity and primary productivity in San Francisco Bay, upstream rivers, and ocean;
    3. Evaluate the effects of exports, other in-Delta, and upstream factors on the abundance of salmon and striped bass;
    4. Review and critique agency fishery models that link water exports with the abundance of striped bass and salmon;

5. Develop a model based on GLMs to estimate the relative impact of exports, water facility operating variables, tidal phase, salinity, temperature, and other variables on the survival of salmon smolts as they migrate through the Delta;
6. Reconstruct the natural hydrology of the Central Valley using water balances, vegetation mapping, reservoir operation models to simulate flood basins, precipitation records, tree ring research, and historical research;
7. Evaluate the relationship between biological indicators of estuary health and down-estuary position of a salinity surrogate (X2);
8. Use real-time fisheries monitoring data to quantify impact of exports on fish migration;
9. Refine/develop statistical theory of autocorrelation and use to assess strength of relationships between biological and flow variables;
10. Collect, compile, and analyze water quality and toxicity data for surface waters in the Central Valley to assess the role of water quality in fishery declines;
11. Assess mitigation measures, including habitat restoration and changes in water project operation, to minimize fishery impacts;
12. Evaluate the impact of unscreened agricultural water diversions on abundance of larval fish;
13. Prepare and present testimony on the impacts of water resources development on Bay hydrodynamics, salinity, and temperature in water rights hearings;
14. Evaluate the impact of boat wakes on shallow water habitat, including interpretation of historical aerial photographs;
15. Evaluate the hydrodynamic and water quality impacts of converting Delta islands into reservoirs;
16. Use a hydrodynamic model to simulate the distribution of larval fish in a tidally influenced estuary;
17. Identify and evaluate non-export factors that may have contributed to fishery declines, including predation, shifts in oceanic conditions, aquatic toxicity from pesticides and mining wastes, salinity intrusion from channel dredging, loss of riparian and marsh habitat, sedimentation from upstream land alternations, and changes in dissolved oxygen, flow, and temperature below dams.

- Developed, directed, and participated in a broad-based research program on environmental issues and control technology for energy industries including petroleum, oil shale, coal mining, and coal slurry transport. Research included evaluation of air and water pollution, development of novel, low-cost technology to treat and dispose of wastes, and development and application of geohydrologic models to evaluate subsurface contamination from in-situ retorting. The program consisted of government and industry contracts and employed 45 technical and administrative personnel.

- Coordinated an industry task force established to investigate the occurrence, causes, and solutions for corrosion/erosion and mechanical/engineering failures in the waterside systems (e.g., condensers, steam generation equipment) of power plants. Corrosion/erosion failures caused by water and steam contamination that were investigated included waterside corrosion caused by poor microbiological treatment of cooling water, steam-side corrosion caused by ammonia-oxygen attack of copper alloys, stress-corrosion cracking of copper alloys in the air cooling sections of condensers, tube sheet leaks, oxygen in-leakage through condensers, volatilization of silica in boilers and carry over and deposition on turbine blades, and iron corrosion on boiler tube walls. Mechanical/engineering failures investigated included: steam impingement attack on the steam side of condenser tubes, tube-to-tube-sheet joint leakage, flow-induced vibration, structural design problems, and mechanical failures due to stresses induced by shutdown, startup and cycling duty, among others. Worked with electric utility plant owners/operators, condenser and boiler vendors, and architect/engineers to collect data to document the occurrence of and causes for these problems, prepared reports summarizing the investigations, and presented the results and participated on a committee of industry experts tasked with identifying solutions to prevent condenser failures.
- Evaluated the cost effectiveness and technical feasibility of using dry cooling and parallel dry-wet cooling to reduce water demands of several large natural-gas fired power plants in California and Arizona.
- Designed and prepared cost estimates for several dry cooling systems (e.g., fin fan heat exchangers) used in chemical plants and refineries.
- Designed, evaluated, and costed several zero liquid discharge systems for power plants.
- Evaluated the impact of agricultural and mining practices on surface water quality of Central Valley steams. Represented municipal water agencies on several federal and state advisory committees tasked with gathering and assessing relevant technical information, developing work plans, and providing oversight of technical work to investigate toxicity issues in the watershed.

AIR QUALITY/PUBLIC HEALTH

- Prepared or reviewed the air quality and public health sections of hundreds of EIRs and EISs on a wide range of industrial, commercial and residential projects.
- Prepared or reviewed hundreds of NSR and PSD permits for a wide range of industrial facilities.

- Designed, implemented, and directed a 2-year-long community air quality monitoring program to assure that residents downwind of a petroleum-contaminated site were not impacted during remediation of petroleum-contaminated soils. The program included real-time monitoring of particulates, diesel exhaust, and BTEX and time integrated monitoring for over 100 chemicals.
- Designed, implemented, and directed a 5-year long source, industrial hygiene, and ambient monitoring program to characterize air emissions, employee exposure, and downwind environmental impacts of a first-generation shale oil plant. The program included stack monitoring of heaters, boilers, incinerators, sulfur recovery units, rock crushers, API separator vents, and wastewater pond fugitives for arsenic, cadmium, chlorine, chromium, mercury, 15 organic indicators (e.g., quinoline, pyrrole, benzo(a)pyrene, thiophene, benzene), sulfur gases, hydrogen cyanide, and ammonia. In many cases, new methods had to be developed or existing methods modified to accommodate the complex matrices of shale plant gases.
- Conducted investigations on the impact of diesel exhaust from truck traffic from a wide range of facilities including mines, large retail centers, light industrial uses, and sports facilities. Conducted traffic surveys, continuously monitored diesel exhaust using an aethalometer, and prepared health risk assessments using resulting data.
- Conducted indoor air quality investigations to assess exposure to natural gas leaks, pesticides, molds and fungi, soil gas from subsurface contamination, and outgasing of carpets, drapes, furniture and construction materials. Prepared health risk assessments using collected data.
- Prepared health risk assessments, emission inventories, air quality analyses, and assisted in the permitting of over 70 1 to 2 MW emergency diesel generators.
- Prepare over 100 health risk assessments, endangerment assessments, and other health-based studies for a wide range of industrial facilities.
- Developed methods to monitor trace elements in gas streams, including a continuous real-time monitor based on the Zeeman atomic absorption spectrometer, to continuously measure mercury and other elements.
- Performed nuisance investigations (odor, noise, dust, smoke, indoor air quality, soil contamination) for businesses, industrial facilities, and residences located proximate to and downwind of pollution sources.

PUBLICATIONS AND PRESENTATIONS (Partial List - Representative Publications)

J.P. Fox, T.P. Rose, and T.L. Sawyer, Isotope Hydrology of a Spring-fed Waterfall in Fractured Volcanic Rock, 2007.

C.E. Lambert, E.D. Winegar, and Phyllis Fox, Ambient and Human Sources of Hydrogen Sulfide: An Explosive Topic, Air & Waste Management Association, June 2000, Salt Lake City, UT.

San Luis Obispo County Air Pollution Control District and San Luis Obispo County Public Health Department, *Community Monitoring Program,* February 8, 1999.

The Bay Institute, *From the Sierra to the Sea. The Ecological History of the San Francisco Bay-Delta Watershed*, 1998.

J. Phyllis Fox, *Well Interference Effects of HDPP's Proposed Wellfield in the Victor Valley Water District*, Prepared for the California Unions for Reliable Energy (CURE), October 12, 1998.

J. Phyllis Fox, *Air Quality Impacts of Using CPVC Pipe in Indoor Residential Potable Water Systems*, Report Prepared for California Pipe Trades Council, California Firefighters Association, and other trade associations, August 29, 1998.

J. Phyllis Fox and others, *Authority to Construct Avila Beach Remediation Project*, Prepared for Unocal Corporation and submitted to San Luis Obispo Air Pollution Control District, June 1998.

J. Phyllis Fox and others, *Authority to Construct Former Guadalupe Oil Field Remediation Project*, Prepared for Unocal Corporation and submitted to San Luis Obispo Air Pollution Control District, May 1998.

J. Phyllis Fox and Robert Sears, *Health Risk Assessment for the Metropolitan Oakland International Airport Proposed Airport Development Program*, Prepared for Plumbers & Steamfitters U.A. Local 342, December 15, 1997.

Levine-Fricke-Recon (Phyllis Fox and others), *Preliminary Endangerment Assessment Work Plan for the Study Area Operable Unit, Former Solano County Sanitary Landfill, Benicia, California*, Prepared for Granite Management Co. for submittal to DTSC, September 26, 1997.

Phyllis Fox and Jeff Miller, "Fathead Minnow Mortality in the Sacramento River," *IEP Newsletter*, v. 9, n. 3, 1996.

Jud Monroe, Phyllis Fox, Karen Levy, Robert Nuzum, Randy Bailey, Rod Fujita, and Charles Hanson, *Habitat Restoration in Aquatic Ecosystems. A Review of the Scientific Literature Related to the Principles of Habitat Restoration*, Part Two, Metropolitan Water District of Southern California (MWD) Report, 1996.

Phyllis Fox and Elaine Archibald, *Aquatic Toxicity and Pesticides in Surface Waters of the Central Valley*, California Urban Water Agencies (CUWA) Report, September 1997.

Phyllis Fox and Alison Britton, *Evaluation of the Relationship Between Biological Indicators and the Position of X2*, CUWA Report, 1994.

Phyllis Fox and Alison Britton, *Predictive Ability of the Striped Bass Model*, WRINT DWR-206, 1992.

J. Phyllis Fox, *An Historical Overview of Environmental Conditions at the North Canyon Area of the Former Solano County Sanitary Landfill*, Report Prepared for Solano County Department of Environmental Management, 1991.

J. Phyllis Fox, *An Historical Overview of Environmental Conditions at the East Canyon Area of the Former Solano County Sanitary Landfill*, Report Prepared for Solano County Department of Environmental Management, 1991.

Phyllis Fox, *Trip 2 Report, Environmental Monitoring Plan, Parachute Creek Shale Oil Program*, Unocal Report, 1991.

J. P. Fox and others, "Long-Term Annual and Seasonal Trends in Surface Salinity of San Francisco Bay," *Journal of Hydrology*, v. 122, p. 93-117, 1991.

J. P. Fox and others, "Reply to Discussion by D.R. Helsel and E.D. Andrews on Trends in Freshwater Inflow to San Francisco Bay from the Sacramento-San Joaquin Delta," *Water Resources Bulletin*, v. 27, no. 2, 1991.

J. P. Fox and others, "Reply to Discussion by Philip B. Williams on Trends in Freshwater Inflow to San Francisco Bay from the Sacramento-San Joaquin Delta," *Water Resources Bulletin*, v. 27, no. 2, 1991.

J. P. Fox and others, "Trends in Freshwater Inflow to San Francisco Bay from the Sacramento-San Joaquin Delta," *Water Resources Bulletin*, v. 26, no. 1, 1990.

J. P. Fox, "Water Development Increases Freshwater Flow to San Francisco Bay," *SCWC Update*, v. 4, no. 2, 1988.

J. P. Fox, *Freshwater Inflow to San Francisco Bay Under Natural Conditions*, State Water Contracts, Exhibit 262, 58 pp., 1987.

J. P. Fox, "The Distribution of Mercury During Simulated In-Situ Oil Shale Retorting," *Environmental Science and Technology*, v. 19, no. 4, pp. 316-322, 1985.

J. P. Fox, "El Mercurio en el Medio Ambiente: Aspectos Referentes al Peru," (Mercury in the Environment: Factors Relevant to Peru) Proceedings of Simposio Los Pesticidas y el Medio Ambiente," ONERN-CONCYTEC, Lima, Peru, April 25-27, 1984. (Also presented at Instituto Tecnologico Pesquero and Instituto del Mar del Peru.)

J. P. Fox, "Mercury, Fish, and the Peruvian Diet," *Boletin de Investigacion*, Instituto Tecnologico Pesquero, Lima, Peru, v. 2, no. 1, pp. 97-116, l984.

J. P. Fox, P. Persoff, A. Newton, and R. N. Heistand, "The Mobility of Organic Compounds in a Codisposal System," *Proceedings of the Seventeenth Oil Shale Symposium*, Colorado School of Mines Press, Golden, CO, 1984.

P. Persoff and J. P. Fox, "Evaluation of Control Technology for Modified In-Situ Oil Shale Retorts," *Proceedings of the Sixteenth Oil Shale Symposium*, Colorado School of Mines Press, Golden, CO, 1983.

J. P. Fox, *Leaching of Oil Shale Solid Wastes: A Critical Review*, University of Colorado Report, 245 pp., July 1983.

J. P. Fox, *Source Monitoring for Unregulated Pollutants from the White River Oil Shale Project*, VTN Consolidated Report, June 1983.

A. S. Newton, J. P. Fox, H. Villarreal, R. Raval, and W. Walker II, *Organic Compounds in Coal Slurry Pipeline Waters*, Lawrence Berkeley Laboratory Report LBL-15121, 46 pp., Sept. 1982.

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BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
U.S. DEPARTMENT OF TRANSPORTATION

Advance Notice of Proposed Rulemaking

Hazardous Materials:
Rail Petitions and Recommendations To Improve the
Safety of Railroad Tank Car Transportation

PHMSA-2012-0082 (HM-251)
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Comments of the Natural Resources Defense Council,
Sierra Club and Oil Change International on behalf of

Earthjustice
ForestEthics
Public Citizen
Friends of the Earth
Spokane Riverkeeper
Columbia Riverkeeper
Puget Soundkeeper Alliance
Friends of Grays Harbor
Natural Resources Council of Maine
Benicia Good Neighbor Steering Committee
Community In-power and Development Association
Vermont Chapter of the Sierra Club
Audubon Society of New Hampshire

Submitted December 5, 2013

I. INTRODUCTION

These comments are submitted, in response to the above-captioned Advance Notice of Proposed Rulemaking by the Sierra Club, Oil Change International and the Natural Resources Defense Council on behalf of their millions of members and active supporters, and on behalf of Earthjustice, ForestEthics, Public Citizen, Friends of the Earth, Spokane Riverkeeper, Columbia Riverkeeper, Puget Soundkeeper Alliance, Friends of Grays Harbor, Natural Resources Council of Maine, Benicia Good Neighbor Steering Committee, Community In-power and Development

Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail

Prepared

by

Ian Goodman
Brigid Rowan

on behalf of
Oil Change International

Before the
Pipeline and Hazardous Materials Safety Administration
in the Context of
Hazardous Materials: Rail Petitions and Recommendations to Improve the Safety of Railroad Tank Car Transportation
Docket No. PHMSA-2012-0082 (HM-251)

the goodman group, ltd.
http://www.thegoodman.com/

November 8, 2013

Table of Contents

1. Introduction

This analysis was prepared by The Goodman Group, Ltd. (TGG), a consulting firm specializing in energy and regulatory economics,[1] on behalf of Oil Change International. Any findings, conclusions or opinions are those of TGG and the authors and do not necessarily reflect those of Oil Change International.

The costs of crude by rail (CBR) accidents/spills can be very large. This analysis demonstrates that a major crude by rail (CBR) unit train accident/spill could cost $1 billion or more for a single event.

The following examples provide key support for our findings:

1. The explosion, fire and spill of Bakken crude from a train derailment in Lac-Mégantic, QC (2013): The Lac-Mégantic rail accident/spill will likely have costs in the order of $500 million to $1 billion. Costs/damages for a similar incident could have been substantially higher had it occurred in a more populated area. Lac-Mégantic is also relevant in that it shows how an accident involving highly flammable light crude (such as the Bakken crude) can have devastating consequences even in a small town in terms of loss of human life and widespread explosion and fire damage to surrounding property.

2. The spill of tar sands dilbit[2] from Enbridge's Line 6B in Marshall, MI (2010): This rupture had costs of about $1 billion for Enbridge. The spill volumes at Marshall were within the range of the amount of spill possible (and, in fact, substantially less than the maximum spill) if a crude by rail unit train released much of its cargo. Costs/damages for similar incident could have also been substantially higher had it occurred in a more populated area. Marshall is also relevant in

[1] www.thegoodman.com This analysis was co-authored by Ian Goodman and Brigid Rowan.
[2] Diluted bitumen. Raw bitumen (a very heavy asphalt-like crude produced from the Alberta tar sands) is diluted for the purposes of rail and pipeline transport. Bitumen is transported in various forms, including a) SCO (raw bitumen upgraded to light synthetic crude oil), b) raw bitumen mixed with a petroleum-based diluent (such as naphtha or condensate) to make it less viscous, or c) raw bitumen (no diluent). SCO and dilbit (diluted bitumen to pipeline specifications, 25–30% diluent) can be transported in standard (non-coiled and non-insulated) tank cars and pipelines. Railbit (bitumen with 15–20% diluent) and raw bitumen can be transported in coiled and insulated tank cars (which are also sometimes used to transport dilbit). Keystone XL Draft Supplemental EIS, p. 1.4-49. Accessed October 30, 2013. http://keystonepipeline-xl.state.gov/documents/organization/205654.pdf

showing the high potential cost of dilbit spills into water (and rail lines are often highly proximate to water).[3]

The AAR petition for rulemaking states:[4]

> AAR surveyed its members for information on derailments involving packing group I and II materials from '2004-2008. The derailments resulted in one fatality and eleven injuries, the release of approximately 925,000 gallons of these hazardous materials, and cleanup costs totaling approximately $63 million.

The Village of Barrington petition for rulemaking responds:[5]

> Furthermore, while AAR claims that derailment costs totaled approximately $64 million over the past five years, including equipment, lading, response and environmental remediation costs," [footnote 17 in original: March 9, 2011 Petition for Rulemaking letter to Dr. Magdy EI-Sibae from Michael Rush of the Association of American Railroads at page 2, footnote 7.] Petitioners question the accuracy of industry's cost-benefit claims. In reviewing the derailment cost chart at Attachment B of AAR's petition, PHMSA should note that there is no apparent accounting for costs associated with civil litigation in the wake of derailments. However, in the Cherry Valley/Rockford derailment, CN paid over $36 million in October of 2011 to settle a lawsuit brought by the family of only one victim. AAR's chart, however, reflects costs of only $8 million for that incident. [footnote 18 in original: At the very least, Petitioners believe it would make sense for the PHMSA to ascertain the costs stemming from civil litigation for the entire list of derailments incidents that the AAR provided to your office on March 9, 2011. Even if it doesn't yet completely balance the cost-benefit equation in favor of public safety, Petitioners would guess that the plaintiffs' bar would look forward to securing ever higher awards for future victims of derailments based on the public record demonstrating that industry chose to do nothing meaningful in terms of investing in a retrofit program of tank cars that are known to be dangerous and that are increasingly serving as a rolling pipeline for the ethanol and crude oil industries.]

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[3] The discussion of the costs of the Lac-Mégantic disaster and the Marshall, MI pipeline rupture is partly based on excerpts from a TGG report filed as written expert testimony at Canada's National Energy Board:
"The Relative Economic Costs and Benefits of the Line 9B Reversal and Line 9 Capacity Expansion," August 8, 2013, pp. 38-41. Accessed October 23, 2013.
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=985663&objAction=Open

[4] See http://www.regulations.gov/#!documentDetail;D=PHMSA-2012-0082-0005 p. 2. Accessed October 29, 2013.

[5] See http://www.regulations.gov/#!documentDetail;D=PHMSA-2012-0082-0006 p. 8. Accessed October 29, 2013.

In fact, even a single accident relating to a crude by rail unit train can have dramatically higher costs than the costs taken into account in the AAR's cost-benefit claims. As further explained in this briefing, this analysis will demonstrate that a major crude by rail unit train accident/spill, involving either dilbit or a very light crude such as Bakken, could cost $1 billion or more for a single event.

We have limited our cost analysis to environmental and socio-economic impacts that directly affect economic activity and can be somewhat readily (albeit approximately) quantified using market economics. These costs escalate very quickly in more densely populated urban areas. Moreover, as we have witnessed firsthand in Quebec, in summer 2013, unconventional crudes (such as Bakken and dilbit) have hazardous characteristics (notably flammability), such that their unsafe transport can result in the loss of human life. We have not attempted to assign a cost to potential effects on human health and safety or to broader effects on ecosystems (notably residual effects).[6]

As noted above, two relevant examples to support our findings that a single unit-train accident/spill could result in very large costs are the following:

1. the explosion, fire and spill of Bakken crude from a train derailment in Lac-Mégantic, QC (2013).
2. the spill of tar sands dilbit from Enbridge's Line 6B in Marshall, MI (2010).

For each example, TGG will provide:

1. description of the disaster;
2. the cost and sources of the cost data;
3. the relevance of the example to estimating the potential costs of CBR accidents/spills.

[6] Residual effects are those effects remaining after implementation of mitigation measures, such as emergency response and decontamination efforts.

2. Estimated Costs of the Crude by Rail Disaster at Lac-Mégantic

2.1. Description of Disaster

According to the Transportation Safety Board of Canada (TSB), "[o]n July 6 2013, a unit train carrying petroleum crude oil operated by Montreal, Maine & Atlantic Railway (MMA) derailed numerous cars in Lac-Mégantic, Quebec, and a fire and explosions ensued."[7]

The train with five locomotives was pulling 72 DOT-111 tanker cars full of light crude oil from the Bakken shale play in North Dakota to the Irving Oil refinery in Saint John, New Brunswick. The train was operated by Montreal Maine & Atlantic Railway. The train broke away and derailed, unleashing an explosive ball of burning Bakken crude, which incinerated the downtown core of this small Quebec town.[8]

Quebec's Department of Sustainable Development, Environment and Parks reports that this rail accident released 6.0 million litres[9] of crude oil into the environment (affecting soil, water and air).[10] Among its other findings (as of October 28, 2013):

A total of 7.7 million litres[11] of crude oil were on the runaway MMA train

from a total of 72 tankers, 63 spilled and 9 avoided spilling during the accident

43 million litres of oily water have been recovered from Lac-Mégantic's city centre (sewer system, lake, and grounds)

52,000 litres of oily water removed from the nearby Chaudière River

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[7] See TSB website, Railway investigation R13D0054. Accessed October 29, 2013. http://www.bst-tsb.gc.ca/eng/enquetes-investigations/rail/2013/R13D0054/R13D0054.asp

[8] "Lac-Mégantic: What we know, what we don't," Montreal Gazette, July 22, 2013. Accessed August 2, 2013. http://www.montrealgazette.com/news/M%C3%A9gantic+What+know+what+know/8626661/story.html

[9] Equivalent to 1.6 million gallons.

[10] See Quebec Department of Sustainable Development, Environment and Parks website, Train Accident in Lac-Mégantic (content in French: *Ministère du Développement durable, de l'Environnement, de la Faune et des Parcs (MDDEFP), Accident ferroviaire à Lac-Mégantic*),.Accessed November 8, 2013 http://www.mddep.gouv.qc.ca/lac-megantic/index.htm; and specifically Summary Table on quantities of oil estimated as of October 28, 2013 (*Tableau-Synthèse: Estimation au 28 octobre 2013 des quantités de pétrole brut léger impliquées dans l'accident à Lac-Mégantic*) http://www.mddefp.gouv.qc.ca/lac-megantic/20131028-tableau-synthese-petrole.pdf

[11] Equivalent to 2.0 million gallons.

the oily water recovered has concentrations of oil ranging from 2% to 50%, and it is not possible to determine the exact amount of oil actually recovered.

"The catastrophe killed 47 residents and levelled more than 40 buildings." [12]

According to a September 11, 2013 TSB news release, "TSB test results indicate that the level of hazard posed by the petroleum crude oil transported in the tank cars on the accident train was not accurately documented." The crude was "offered for transport, packaged, and transported as a Class 3, PG III product, which represented it as a lower hazard, less volatile flammable liquid."[13]

2.2. Costs and Sources of Cost Data

The TSB investigation into the accident is still ongoing.[14] It is still too early to know the final costs for this disaster (including decontamination, town reconstruction, economic recovery, and compensation for victims' families); but **TGG estimates these costs to be in the hundreds of millions (in the order of $500 million to $1 billion)**.

Preliminary clean-up bills for damage to the town doubled in the weeks following the accident from $4 million to almost $8 million. The MM&A Railway stated at the end of July that it was unable to pay clean-up costs because it was not getting funds from its insurers. At the time, MM&A had outstanding bills for $7.8 million. MM&A also publicly raised the concern that it could go bankrupt.[15] In response, the Quebec government ordered World Fuel Services Corp. to assist with the clean-up. World Fuel "purchased the oil from producers in North Dakota's Bakken region, then leased and loaded rail

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[12] McNish, Jacquie and Justin Giovanetti, "Oil Company Disputes Lac-Méganitc Cleanup Order," Globe and Mail. Accessed August 4.
http://www.theglobeandmail.com/news/national/oil-company-disputes-lac-megantic-cleanup-order/article13518237/

[13] "TSB calls on Canadian and U.S. regulators to ensure properties of dangerous goods are accurately determined and documented for safe transportation," TSB News release, September 11, 2013. Accessed October 29, 2013.
http://www.bst-tsb.gc.ca/eng/medias-media/communiques/rail/2013/r13d0054-20130911.asp
The news release further explains that this misclassification may partly explain why the crude ignited so quickly following the rupture.

[14] See the TSB active investigation page for Lac-Mégantic:
http://www.bst-tsb.gc.ca/eng/enquetes-investigations/rail/2013/R13D0054/R13D0054.asp.

[15] Blatchford, Andy, "Railway says it can't pay for Lac-Mégantic disaster cleanup"
http://www.theglobeandmail.com/news/national/mma-lays-off-nearly-one-third-of-quebec-workforce-union/article13496970/#dashboard/follows/

cars and arranged for their transport to an Irving Oil refinery in New Brunswick."[16] World Fuel is disputing the cleanup order.

> "In the end, says one expert in civil responsibility, taxpayers could be stuck with a bill in the hundreds of millions of dollars.
>
> Quebec law professor Daniel Gardner says he highly doubts MM&A has enough coverage to absorb the massive, combined financial liabilities of damages like environmental cleanup, emergency-crew salaries and lawsuits.
>
> In fact, he believes the Lac-Megantic derailment could have more financial consequences than any other land disaster in North American history.
>
> "The whole cost of this will be far closer to $1 billion than to $500 million," said the Universite Laval academic, adding he would be surprised if the railway had a total of $500 million in coverage.
>
> "What will probably happen? ...The company will go bankrupt, insurance coverage won't be enough."
>
> Gardner expects governments will wind up covering the difference.[17]

On August 7, 2013, MM&A filed for bankruptcy in both Canada (Quebec) and the US (Maine).[18]

> "It has become apparent that the obligations of both companies now exceed the value of their assets, including prospective insurance recoveries," MM&A chairman Edward Burkhardt said in a statement Wednesday.
>
> Filing for bankruptcy is "the best way to ensure fairness of treatment to all in these tragic circumstances," he said.
>
> The decision means the company will start a judge-supervised process to determine how much money will be paid to its various creditors. The process, which allows the company to tackle its unmanageable debt load and remain viable, can be lengthy and typically places secured creditors ahead of those seeking compensation through a lawsuit.

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[16] See footnote 12.
[17] See footnote 15.
[18] Mackrael, Kim and Tu Thanh Ha, "MM&A files for creditor protection after Lac-Mégantic rail disaster" Globe and Mail. Accessed August 7. http://www.theglobeandmail.com/news/national/rail-company-involved-in-megantic-disaster-files-for-bankruptcy/article13644535/#dashboard/follows/

> MM&A's insurance provider, XL Group, has so far declined to cover the cleanup bills, leaving the province to step in and pay more than $8-million to ensure the work continues.
>
> The court documents indicate that XL has no plans to contribute to continuing environmental recovery costs because it has decided to prioritize claims from victims affected by the disaster. MM&A's insurance policy with XL covers the company for up to $25-million, according to the court documents.
>
> Because of the number of claims and the amounts being claimed, the insurer "cannot provide for payment of covered environmental cleanup costs to the detriment of the third-party claimants, especially where the amounts of the claims exceed the limit of the coverage," the documents state.

Based on the information provided above, the now bankrupt MM&A has liabilities in excess of assets, minimal insurance coverage ($25 million); and the insurer has so far refused to pay environmental cleanup costs.

Ongoing squabbling has recently intensified between Quebec and the Canadian federal government over who should pay for the clean-up, economic recovery and town reconstruction. Quebec is insisting that the federal government pitch in more than the $60M they have committed to. In the October 2013 Throne Speech, the federal government promised to help more with decontamination and reconstruction but have yet to commit to an exact amount.

The Quebec government has still not supplied the federal government with a cost estimate for the cleanup and reconstruction. Federal officials refuse to commit to a fixed amount without a final bill.[19]

While MM&A is bankrupt, some **$25 million** in derailment insurance policy is earmarked by the US bankruptcy trustee for the victim's families. There is a possibility that additional compensation could be obtained for the families from a second insurance policy or from the sale of the company's assets, but these amounts are uncertain.[20]

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[19] The Globe and Mail, "Throne Speech to promise help with Lac-Mégantic cleanup, but not a 'blank cheque,' insiders say," October 15, 2013. http://www.theglobeandmail.com/news/politics/throne-speech-to-promise-help-with-lac-megantic-cleanup-but-not-a-blank-cheque-insiders-say/article14883079/#dashboard/follows/

[20] Montreal Gazette, "Quebec rail victims could begin to see compensation in mid-2014: U.S. trustee," October 22, 2013. http://www.montrealgazette.com/business/Quebec+rail+victims+could+begin+compensation+mid2014/9066861/story.html

Certainly, even individual victims of derailment have recently received compensation greater than $25 million,[21] therefore higher compensation, if available, would be justifiable.

On the **decontamination costs alone** there are a series of estimates:

- In late July 2013, a Quebec-based Ecotoxicologist, Emilien Pelletier, estimates that the bill just for decontamination would be **$500 million** and that doesn't include town reconstruction.[22]

- In early August 2013, MM&A was reported to have estimated the decontamination costs at **$200 million** in court documents.[23]

- In an October 2013 article, the Quebec government recently estimated the **soil decontamination costs alone at $150 million**.[24]

Overall costs estimates vary from several hundred million dollars to $1 billion:

- As indicated above, Quebec law professor, Daniel Gardner, estimated in August that the costs would far closer to **$1 billion than $500 million**.[25]

- In September 2013, the Toronto Star reported that cleanup costs are pegged as high as **$500 million by some estimates**.[26]

- On October 15, 2013, the Globe and Mail (Canada's National paper), indicated that "[e]xperts and government officials expect that **the bill will easily reach $200-million, and could even end up in the vicinity of $1-billion**."[27]

In light of the above, it would appear that the minimum decontamination costs would be $200 million and the minimum total costs (decontamination, town reconstruction and

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[21] See footnote 5.
[22] See http://www.ledevoir.com/environnement/actualites-sur-l-environnement/383941/blanchet
[23] See http://www.theglobeandmail.com/news/national/quebec-could-still-be-on-hook-for-cleanup-bill/article13680378/#dashboard/follows/ and http://www.thestar.com/news/canada/2013/08/09/lac_megantic_cleanup_to_stretch_into_next_year.html
[24] See http://www.thestar.com/news/canada/2013/10/03/lacmegantic_ottawa_to_pitch_in_more_money_for_cleanup_of_train_derailment.html
[25] See footnote 15.
[26] See http://www.thestar.com/news/canada/2013/09/24/lac_megantic_cleanup_quebec_asks_federal_government_to_share_bill.html#
[27] See footnote 19.

economic recovery, and compensation for victims' families) would be approximately $500 million. The total bill could escalate to $1 billion and beyond. The updated information is consistent with TGG's August 2013 estimate from the NEB expert report:

"It is far too early to know the final costs for this disaster but they are estimated to be in the hundreds of millions, and possibly exceed $1 billion." [28]

2.3. Relevance of Lac-Mégantic to Estimating the Costs of CBR Accidents/Spills

The Lac-Mégantic tragedy is directly relevant to an estimation of the costs of a major CBR accident/spill for the following reasons:

1. It demonstrates the consequences of a CBR accident in a small town by a lake, thus proximate to people, water and economic activity.
2. The Lac-Mégantic tragedy demonstrates the effect of a rupture of 63 tank cars on a unit train with a total of 72 tankers, all carrying Bakken crude.
3. Bakken crude, which caused the explosion, is very light, and has hazardous characteristics (notably flammability).
4. Rail is now transporting over 600,000 barrels per day (and over 60% of the total) from Bakken production.[29]
5. More generally, the rapid expansion of CBR results from the rapid expansion in production and transport of unconventional crudes (Bakken and other light crudes from shale/tight oil plays and dilbit and other heavy crudes from Canadian tar sands).[30]

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[28] See footnote 3, p. 39.

[29] See North Dakota Pipeline Authority website. Accessed October 30, 2013. http://northdakotapipelines.com/directors-cut/.
Monthly Updates for April 2013-October 2013 (February 2013-August 2013 data), reporting transport by rail ranging from 600,000 to 700,000 barrel per day, comprising 61-75% of total Bakken production.

[30] To date, a sizable proportion of overall recent CBR activity relates to Bakken production. The Keystone XL Draft Supplemental EIS (KXL DSEIS) assumes that CBR could be rapidly expanded to transport expanded Canadian tar sands production of dilbit and other heavy crudes, so as to provide a viable alternative to expanded pipeline capacity. The KXL DSEIS analysis of tar sands CBR is flawed and potentially misleading because it assumes that CBR can be quickly and vastly scaled up, with no significant operating, logistical, economic or regulatory constraints. Nonetheless, some Western Canadian production is already being transported by rail into the US (including dilbit, railbit, and raw bitumen, from both tar sands and non-tar sands), and there is a potential for further expansion of CBR transport of unconventional Canadian crudes.
See footnote 29; Titterton, Paul, Tank Car Update: Presentation to SWARS, February 28, 2013. Accessed October 30, 2013.
http://www.swrailshippers.com/swars_pdfs/2013_gatx_presentation.pdf;
(footnote continued on next page)

6. In addition to the devastation of the Lac-Mégantic town center, there has been significant release of crude oil (6.0 million liters or 1.6 million gallons) into the environment (affecting soil, water and air).[31]
7. There are very serious concerns about who will bear the financial responsibility for the disaster.

Although the Lac-Mégantic accident/spill was devastating and will likely have costs in the order of $500 million to $1 billion, it is nowhere near a worst-case scenario for a CBR accident.

Costs/damages for a similar incident could have been substantially higher had it occurred in a more populated area. Lac-Mégantic demonstrates how an accident involving highly flammable light crude (such as the Bakken crude) can have devastating consequences even in a small town in terms of loss of human life and widespread explosion and fire damage to surrounding property. In an urban area, the effects of such an accident could be catastrophic and costs could easily escalate to the multi-billion dollar range.[32]

(footnote continued from previous page)
Keystone XL Draft Supplemental EIS, pp. 1.4-33 – 1.4-60. Accessed October 30, 2013. http://keystonepipeline-xl.state.gov/documents/organization/205654.pdf;
Goodman, Ian and Brigid Rowan, Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis, April 22, 2013, pp. 33-50, Adobe pp. 267-284
http://switchboard.nrdc.org/blogs/aswift/Comments%20of%20Sierra%20Club%2C%20et.%20al.%2C%20on%20the%20Keystone%20XL%20DSEIS.4.22.13.pdf

[31] There have been concerns that the spill affected water quality and drinking water in Lac-Mégantic and nearby towns. Authorities continue to monitor water quality.
"Government Examining Lac-Mégantic Health Risks," The Record, July 31, 2013. Accessed August 2, 2013.
http://www.sherbrookerecord.com/content/gov%E2%80%99t-examining-lac-megantic-health-risks;
see also footnote 10.

[32] In the context of the PHMSA rulemaking and elsewhere, some may submit that the Lac-Mégantic accident is an exceptional and possibly worst-case scenario that is unlikely to be repeated. And this particular accident certainly has some attributes that may be atypical or even unique. That said, this accident also occurred in a relatively small town. A similar explosion and fire in a more dense urban area could have had even worse consequences and higher costs. In an urban area, the particular factors in Lac-Mégantic (unattended train rolling down steep grades to crash at high speeds) may be far less likely to occur. On the other hand, in an urban area, there are other risk factors, such as increased danger of collisions with other trains (or other vehicles), as well as proximity to large populations and other infrastructure.

It may also be pointed out that the Lac-Mégantic accident occurred in Canada and that the estimated costs are in Canadian dollars. But in fact, the Lac-Mégantic accident is very relevant for the US. First, US and Canadian dollars now have similar value, so the cost estimates for Lac-Mégantic accident would be similar if presented in US dollars. Second, the accident occurred very close to the US border, on a train that had originated in the US (North Dakota), traveled through numerous US states and cities, and would have again passed through the US (Maine) on its intended routing between Quebec and New Brunswick.

3. Estimated Costs of Enbridge's Line 6B Spill in Marshall, MI

3.1. Description of Disaster

According to the NTSB, following its investigation of the Enbridge Line 6B Spill (emphasis added):[33]

> On Sunday, July 25, 2010, at about 5:58 p.m., a 30 inch-diameter pipeline (Line 6B) owned and operated by Enbridge Incorporated ruptured and spilled crude oil into an ecologically sensitive area near the Kalamazoo River in Marshall, Mich., for 17 hours until a local utility worker discovered the oil and contacted Enbridge to report the rupture.
>
> The NTSB found that the material failure of the pipeline was the result of multiple small corrosion-fatigue cracks that over time grew in size and linked together, creating a gaping breach in the pipe measuring over 80 inches long.
>
> "This investigation identified a complete breakdown of safety at Enbridge. Their employees performed like Keystone Kops and failed to recognize their pipeline had ruptured and continued to pump crude into the environment," said NTSB Chairman Deborah A.P. Hersman. "Despite multiple alarms and a loss of pressure in the pipeline, for more than 17 hours and through three shifts they failed to follow their own shutdown procedures."
>
> […]
>
> Over 840,000 gallons of crude oil - enough to fill 120 tanker trucks - spilled into hundreds of acres of Michigan wetlands, fouling a creek and a river. A Michigan Department of Community Health study concluded that over 300 individuals suffered adverse health effects related to benzene exposure, a toxic component of crude oil.
>
> Line 6B had been scheduled for a routine shutdown at the time of the rupture to accommodate changing delivery schedules. Following the shutdown, operators in the Enbridge control room in Edmonton, Alberta, received multiple alarms indicating a problem with low pressure in the pipeline, which were dismissed as

[33] NTSB Press Release, "Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations," July 10, 2012. Accessed August 3, 2012. http://www.ntsb.gov/news/2012/120710.html

being caused by factors other than a rupture. "Inadequate training of control center personnel" was cited as contributing to the accident.

The investigation found that Enbridge failed to accurately assess the structural integrity of the pipeline, including correctly analyzing cracks that required repair. The NTSB characterized Enbridge's control room operations, leak detection, and environmental response as deficient, and described the event as an "organizational accident."

Following the first alarm, Enbridge controllers restarted Line 6B twice, pumping an additional 683,000 gallons of crude oil, or 81 percent of the total amount spilled, through the ruptured pipeline. The NTSB determined that if Enbridge's own procedures had been followed during the initial phases of the accident, the magnitude of the spill would have been significantly reduced. Further, the NTSB attributed systemic flaws in operational decision-making to a "culture of deviance," which concluded that personnel had a developed an operating culture in which not adhering to approved procedures and protocols was normalized.

The NTSB also cited the Pipeline and Hazardous Materials Safety Administration's weak regulations regarding pipeline assessment and repair criteria as well as a cursory review of Enbridge's oil spill response plan as contributing to the magnitude of the accident.

The investigation revealed that the cracks in Line 6B that ultimately ruptured were detected by Enbridge in 2005 but were not repaired. A further examination of records revealed that Enbridge's crack assessment process was inadequate, increasing the risk of a rupture.

"This accident is a wake-up call to the industry, the regulator, and the public. Enbridge knew for years that this section of the pipeline was vulnerable yet they didn't act on that information," said Chairman Hersman. "Likewise, for the regulator to delegate too much authority to the regulated to assess their own system risks and correct them is tantamount to the fox guarding the hen house. Regulators need regulations and practices with teeth, and the resources to enable them to take corrective action before a spill. Not just after."

As a result of the investigation, the NTSB reiterated one recommendation to PHMSA and issued 19 new safety recommendations to the Department of the Transportation, PHMSA, Enbridge Incorporated, the American Petroleum Institute, the International Association of Fire Chiefs, and the National Emergency Number Association.

3.2. Costs and Sources of Cost Data

As of March 31, 2013, Enbridge indicated in its First Quarter Interim Report to Shareholders that the total clean-up for the spill is now estimated to cost approximately $1 billion. Enbridge's civil penalty for the spill was only $3.7 million.[34] Enbridge also points out that there is a possibility that the clean-up bill will continue to increase as the clean-up is still ongoing.

No lives were lost, but as the NTSB citation above indicates: "over 300 individuals suffered adverse health effects related to benzene exposure, a toxic component of crude oil." Furthermore, "[o]ver 840,000 gallons of crude oil - enough to fill 120 tanker trucks - spilled into hundreds of acres of Michigan wetlands, fouling a creek and a river."

3.3. Relevance of Marshall, MI to Estimating the Costs of CBR Accidents/Spills

The Marshall, MI pipeline disaster is also highly relevant to an estimation of the costs of a major CBR accident/spill for the following reasons:

1. It demonstrates the costs of a dilbit spill in an environmentally sensitive area (with wetlands and proximity to waterways and human population) in a non-urban area.[35] Marshall, MI is not dissimilar to the many areas through which trains are also routed (along waterways in order to minimize elevation and through population centers throughout the US).

2. The spill volumes at Marshall were within the range of the amount of spill possible (and, in fact, substantially less than the maximum spill) if a crude by rail unit train released much of its cargo. 840,000 gallons (or 3.3 million liters) were spilled at Marshall, the equivalent of the full cargo release of 27 tank cars (carrying 31,000 gallons) or 34 tank cars (carrying 25,000 gallons).[36] With

[34] Enbridge First Quarter Interim Report to Shareholders for the Three Months Ended March 31, 2013, Section 11 Contingencies, Adobe p. 67. Accessed August 3, 2013.
See http://www.enbridge.com/InvestorRelations/FinancialInformation/InvestorDocumentsandFilings.aspx and then click on FIRST QUARTER REPORT under 2013.
[35] The population of Marshall is approximately 7,000.
[36] Maximum capacity per tank car typically varies between 25,000 and 31,800 gallons of crude, based on factors including maximum weight limits, tank car design, and type of crude. Capacity will generally be lower for heavy crudes (such as the dilbit spilled at Marshall), which weigh more per gallon than light crudes (such as the Bakken crude spilled at Lac-Mégantic). Likewise, capacity will be lower for tank cars (footnote continued on next page)

transport by unit trains on the rise, and unit trains carrying up to 100+ tank cars, it would be possible for a unit train to spill significantly higher volumes than the 840,000 gallons (or 3.3 million liters) released at Marshall. The 6.0 million liters released at Lac-Mégantic (almost twice the amount released at Marshall) provide support for this finding.

3. In light of recent findings regarding the Line 6B spill, the EPA has recently expressed concerns regarding the additional impacts of tar sands crude spills (versus conventional oil), with a particular concern about spills on waterways.[37]

Regarding the need for improved safety regulation for CBR, there are a number of regulatory lessons from the Marshall, MI rupture that should be considered:

1. The NTSB investigation also clearly indicates that in the case of Enbridge, and with respect to the regulation of pipeline operators, "trust us" isn't good enough. Chair Hersman has insightfully pointed out that "for the regulator to delegate too much authority to the regulated to assess their own system risks and correct them is tantamount to the fox guarding the hen house."[38] Chair Hersman's words are even more relevant for the regulation of transport of hazardous materials by rail, which is in many ways both weaker and more fragmented than the regulation of liquid pipelines.[39]

2. The NTSB investigation pointed out that the Marshall rupture was "a wake-up call" to industry, the regulator, and the public." Enbridge knew for years that the

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(footnote continued from previous page)
which have higher tare (unloaded) weights (such as those with heater coils and insulation, which are also sometimes used to transport dilbit).

[37] Comments of EPA on the Department of State's Keystone XL Draft Supplement Environmental Impact Statement (DSEIS). Accessed October 30, 2013.
http://epa.gov/compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf

[38] See footnote 33.

[39] As described in various other documents in the current proceeding, there is a long history of problems in regard to transport of hazardous materials (notably flammable liquids) by rail, with only a very slow and partial response to tighten standards to insure public safety. See Village of Barrington, Illinois and The Regional Answer to Canadian National (TRAC) - Petition for Rulemaking (P-1587); National Transportation Safety Board - Accident Report - Derailment of CN Freight Train U70691-18 With Subsequent Hazardous Materials Release and Fire Cherry Valley, Illinois June 19, 2009; and National Transportation Safety Board - Safety Recommendation - R-12-5 through -8, R-07-4 (Reiteration)

In the case of liquid pipelines, the pipeline owner/operator is typically responsible for construction and operation of all facilities within its transport system that are handling hazardous materials (notably flammable liquids), including pipes, valves, and pumping stations. By contrast, in the case of rail, the railroads provide motive power and crews to move hazardous materials (notably flammable liquids) in tank cars which are typically owned, loaded, and unloaded by shippers and other entities besides the railroads.

pipeline was vulnerable; much as the rail industry knows that another CBR spill is only a matter of time.

Although the Line 6B rupture caused widespread devastation to the Kalamazoo and surrounding wetlands and, at $1 billion in clean-up costs, holds the record for the single most expensive onshore spill in US history,[40] it is nowhere near the worst-case scenario for a CBR disaster. Similar to the Lac-Mégantic tragedy involving a CBR release of Bakken, the costs/damages for a CBR dilbit spill could be substantially higher in a more populated area, and costs could easily escalate to the multi-billion dollar range. The clean-up of dilbit, especially in waterways is particularly problematic and expensive. Moreover, the condensate can be highly flammable when spilled and this flammability could have catastrophic consequences in a more densely populated area.

[40] See footnote 33.

4. Conclusion

As the examples of the Lac-Mégantic CBR tragedy and the Marshall, MI pipeline rupture have demonstrated, a major CBR unit train accidents/spill could cost $1 billion or more for a single event.

Unit trains now transport unconventional crude, including both dilbit and Bakken, through densely populated urban areas, and this form of transport is rapidly growing. An accident/spill in an urban area could damage and disrupt major infrastructure, result in serious and widespread water and soil contamination, and possibly cause loss of life. The costs of a major unit train derailment in an urban centre could easily escalate into the multi-billion dollar range.

CANADA NEWS

Officials Tighten Crude-Shipping Standards

By BETSY MORRIS and RUSSELL GOLD

Updated Aug. 7, 2013 10:09 p.m. ET

The Federal Railroad Administration plans to start asking shipping companies to supply testing data they use to classify their crude-oil shipments, saying it is concerned that some shipments are being transported in tank cars that aren't safe enough.

In a letter to American Petroleum Institute CEO Jack Gerard last week, the FRA said it is investigating whether some crude shipments contain chemicals—possibly from the hydraulic-fracturing process used to extract it—that make them more hazardous than their classification indicates.

Oil containers sit at a train depot outside Williston, N.D., last month. Oil producers and refiners are increasingly using rail in North Dakota and Texas, w here there aren't enough pipelines. *Getty Images*

The agency told the API it also suspects that mixes of crude and other chemicals might be the cause of an increase in damage to tank cars caused by "severe corrosion." If shippers can't supply their testing data, the FRA said in the letter, it will work with the Pipeline and Hazardous Materials Safety Administration to test the shipments independently.

Companies routinely add highly corrosive hydrochloric acid to fracking fluid to break down rock formations. They also add certain chemicals to kill microorganisms and reduce friction in oil. Frack fluids are exempt from federal disclosure laws, but some companies voluntarily provide details, and some states require a thorough ingredient list.

The action is the latest by the agency to toughen regulation of the transport by rail of crude oil after a runaway train hauling 72 tank cars with crude oil derailed and exploded last month, killing 47 people and ravaging the Quebec town of Lac-Mégantic.

The latest FRA action "looks like a shot over the bow," said Grady Cothen, a former FRA safety official who is now a transportation-policy consultant. "They seem to be saying, 'Get your house in order or we'll do it for you.' "

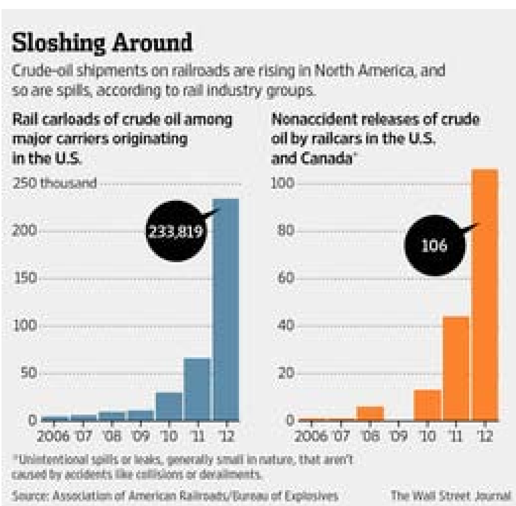
The Quebec disaster follows a number of serious accidents involving hazardous materials and tank cars in recent years that have raised federal regulators' concern. More than 34 million barrels of crude were delivered to U.S. refineries by train in 2012, a fivefold increase compared with a year earlier, according to the Energy Information Administration, the statistical arm of the U.S. Energy Department. The volume is expected to increase again in 2013.

The Canadian Transportation Safety Board said it would analyze and compare numerous fluid samples taken from the Lac-Mégantic accident "to verify the properties of the petroleum product in these tank cars" and to help figure out "why the oil created such a fierce fire that night." It is also analyzing metallurgical samples, damage records and photographs to determine how well the tank cars involved in the derailment were prepared to withstand a crash.

The company that operated that train, Montreal, Maine & Atlantic Railway Ltd., filed for bankruptcy protection Wednesday in U.S. Bankruptcy Court in Bangor, Maine. Its Canadian counterpart filed for protection from creditors.

The FRA moves will likely pose difficulties for some shippers. Oil producers and refiners are increasingly using rail in Texas and North Dakota, where there aren't enough pipelines to get the crude to markets that will command the highest price.

Prentiss Searles, marketing-issues manager for the American Petroleum Institute, said the institute was reviewing the letter to see what, if anything, needed to be done to respond to the FRA's concerns. "Ultimately, we're going to follow the rules and requirements that currently exist. If somebody made a mistake and put the wrong type of crude in the wrong type of tank care, that should not happen," he said.



EOG Resources Inc., a Houston-based energy producer that ships crude from rail yards in Texas and North Dakota, said it was "in close communication with our railroad carriers and is currently reviewing the topics raised by the Federal Railroad Administration." Jeff Hume of Continental Resources Inc., an Oklahoma City-based crude producer, said: "We meet all [Department of Transportation] specifications. If the DOT deems it necessary to change those specifications, we will support what safety experts recommend."

In the detailed letter to the Petroleum Institute, Thomas J. Herrmann, acting director of FRA's office of safety assurance and compliance, spelled out numerous reasons for the agency's concern. In one example, the FRA said a company was shipping crude that should have been classified as flammable in a tank car that hadn't been designed for that material. The agency could "only speculate as to the number of potential crude-oil shipments that are being made in violation of Hazardous Material Regulations," he wrote.

Shippers need to know the chemical makeup of substances they are shipping, the letter said. But FRA said its audits indicate the oil is often classified based on outdated testing and testing that doesn't reflect all the batches of oil from different sources and wells that are being mixed. Crude is frequently shipped in unit trains made up of scores of tank cars, containing oil from different shippers and many wells, some of which has been blended together.

The FRA also noted recurring problems with what it said appeared to be overloaded tank cars. Proper tank-car loading is based on a calculation that involves relative temperatures and gravity to determine the quantity to load without overloading that will result in leaks.

George King, an engineer and technology consultant for Apache Corp., said hydrochloric acid used in fracking typically doesn't return to the surface. "I have never seen anything stronger than a very, very weak vinegar come back in terms of acid," he said.

However, Mr. King said the acid won't mix with crude oil and if stored in a tanker, will settle to the bottom. "Could it be corrosive on steel? Yes," he said.

—Daniel Gilbert contributed to this article.

Write to Betsy Morris at betsy.morris@wsj.com

Expert Report of Greg Karras

Communities for a Better Environment (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
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 "Hydrogen Renewal Project" now subject to reanalysis pursuant to a California Court of Appeals Order,[1] and the "Contra Costa Pipeline Project" now pending before the County.[2] I serve as an expert for CBE in collaboration with labor, academic, and other community based and environmental groups in a project involving comprehensive investigation of environmental health and safety impacts of, and alternatives to, refining denser, more contaminated types of 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" crude oils 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. Most recently, I 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 2012. My curriculum vitae and list of publications are attached hereto.

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[1] <u>See</u> *CBE v. City of Richmond* 184 Cal_App.4th.
[2] <u>See</u> Contra Costa Pipeline Project file, County File #LP072009, SCH #2007062007.

Scope of Review

6. In my role at CBE I have reviewed the proposed project called the Phillips 66 Company Propane Recovery Project (project) and the June 2013 Draft Environmental Impact Report (DEIR) released by Contra Costa County for public review of the proposed project. My review of the project and DEIR reported herein is focused on catastrophic incident, flaring, air emission, cooling system, and climate impacts that could result from the project. My opinions on these matters and the basis for these opinions are stated in this report.

Project Description

7. According to the DEIR, the project would install, at the Phillips 66 San Francisco Refinery (SFR) Rodeo facility, process equipment that would enable the refinery to treat, recover, store, and ship for sale 8,000 barrels[3] of additional liquefied petroleum gases (LPG) daily, including 4,200 b/d of propane and 3,800 b/d of additional[4] butane. This equipment would include:

- a three-reactor hydrotreater installed to the coker and related fuel gas treatment;
- three 120–140 foot tall fractionator towers and two 70 foot tall absorber towers;
- 140 MMBtu[5] per hour of expanded steam boiler capacity to heat this processing;
- six pressurized propane storage tanks totaling 15,000 barrels capacity; and
- two additional rail spurs and a two-sided loading rack to load eight rail cars/day.[6]

8. Ancillary equipment such as additional process vessels, heat exchangers, pumps, and piping would be installed, and modifications to an existing once-through system would increase Bay water use to 40,000 gallons/minute to cool the new processing.[6]

9. Information that is needed to understand and evaluate the environmental implications of this project has, in many cases, been omitted from the DEIR, even though the same information that the DEIR omits is publicly available from other sources. Some forty of these critically important deficiencies in the DEIR's description of the project are discussed in paragraphs 10 through 47.

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[3] 1 barrel (b): 42 gallons; 0.159 cubic meter (m^3). Conversely, 1 m^3: 6.29 barrels; 264 gallons.
[4] The refinery already produces 5,500 b/d of butane for sale, based on the DEIR at 3-21.
[5] MMBtu: 1 million Btu (British thermal units); 1.00551 gigajoule (GJ).
[6] See DEIR at 3-21, Table 3-2, 3-27.

10. The DEIR does not disclose how long the project could be expected to operate. The omission is important because the time frame of the project must be identified to understand and evaluate potential impacts of project operation over that time.

11. There is no good reason why the time over which the project may reasonably be expected to operate should be kept secret in the DEIR. An operating life estimate must have been made to support critical equipment design specifications, such as vessel wall thickness and materials of construction to resist corrosion, and schedules for major maintenance "turnarounds." Phillips 66 also would have used this estimate in financial analysis before committing to the project. Publicly reported data show similar refinery processes have operated for 30–50 years or more.[7] Another EIR for a proposed project at the Richmond refinery suggested it is "reasonable to use past history as a guideline" and to expect similar "equipment to be operated for several decades."[8] Moreover, an EIR for a related project at this refinery disclosed and analyzed a 40 year project duration.[9]

12. Impacts of the project that would emerge later and are obscured by this omission include those from its effects on a concurrent feedstock switch. California refiners' long-stable and dominant sources of crude oil are dwindling, driving an historic refinery crude switch. See Chart 1. Foreign crude was only 6% of total California refinery crude feed in 1990; in 2012 it was 51%.[10] By 2020, roughly three-quarters of the crude refined statewide likely will *not* be from currently producing sources in California or Alaska.[11] Because it relies on dwindling California oil supplies via pipeline for most of its crude feed,[12] the SFR almost certainly will be among those California refineries that switch crudes dramatically during the project's operating life. Indeed, the refinery's 1995 wharf project forecast this outcome,[9] and its recent related project to allow 67% more crude delivered via its wharf[13] would begin to implement the switch. Among other problems, omitting the operating life of the project obscures the project's implications for the choice of new crudes, and the impacts of that feedstock choice.

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[7] See BAAQMD, 2009; and BAAQMD, 2011.
[8] See City of Richmond, 2008. SCH #2005072117, FEIR Response to Comments, page 3.16a-1.
[9] FEIR SCH #91053082 (State Lands, 1995). See section 4 at pages S-1 (stating a 40-year project duration) and 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").
[10] Cal. Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).
[11] See Baker & O'Brien, 2007; and Croft, 2009.
[12] Based on *Oil & Gas Journal* capacity and 11.2–18.7 MMb/y wharf limit.
[13] Based on 11.2 vs 18.7 MMb/yr (DEIR at 5-4); see also ERM & BAAQMD, 2012.

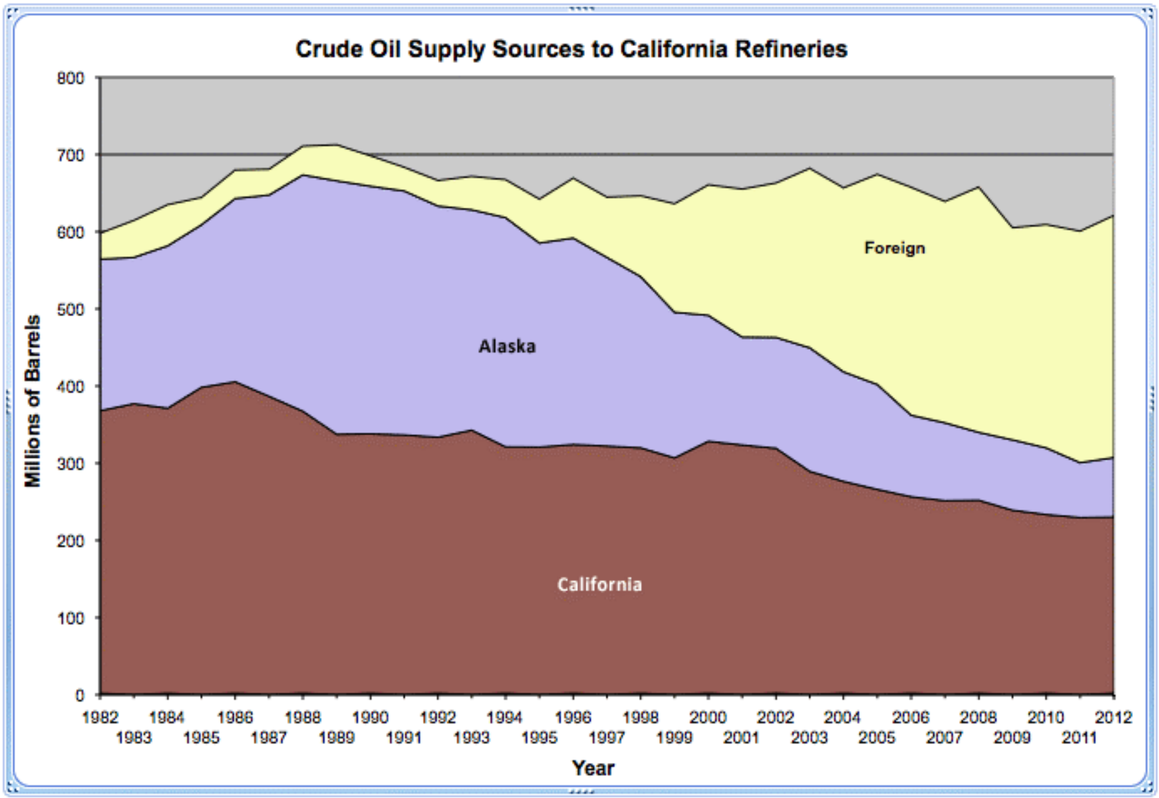

Chart 1. Crude oil supply sources to California refineries, 1982–2012
California Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).

13. The DEIR does not report the crude oil quantity processed by the refinery. Its crude throughput (≈120,000 b/d[14]) must be known to understand and evaluate the scale of environmental impacts resulting from project effects on crude processing.

14. The DEIR does not disclose the changes in crude oil use that could result from the project. Data summarized in Table 1 suggests that meeting project objectives would increase the refinery's total LPG production for export sales to 11.2% of its total crude feed volume, 230–570% of the butane yield from initial distillation of its total crude feed, and 450–1,200% of the propane yield from distilling that crude.[15] This change in

[14] San Francisco Refinery (SFR) crude capacity in b/cd; volume that can be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime (*Oil & Gas Journal*, 2012). This value is close to those the company reported to air and water officials (see Phillips, 2012b; SFR NPDES permit orders).
[15] See data in Table 1. LPG production from DEIR at 3-21. Total post-project butane export is included because project equipment would replace existing processing for production of butane that is now exported and would not change existing crude distillation equipment to change LPG yield from crude distillation. See also EIA Refinery Yield: Monthly average U.S. refinery LPG yield ranged from 1.8–5.7% on crude volume during January 1993–May 2013.

processing would affect refinery production and create environmental impacts in several ways the DEIR does not describe:

- The location of emissions from LPG combustion would change. LPG now used as refinery fuel that is self-produced from crude would be removed from refinery fuel gas and sold for uses involving combustion at a different location.
- Fuel gas heat content would decline, as more LPG is removed from fuel gas and replaced with natural gas, which has a lower heat content. This could affect combustion sources, fuel gas balance, and flare gas recovery refinery wide. Effects from this fuel gas quality problem are different from, and could occur regardless of, the fuel gas quality improvement from sulfur removal that the DEIR describes.
- The refinery would become more reliant on severe processing of the denser oils in the crude stream in order to create enough byproduct gases from "cracking" these oils to fill the LPG gap between its crude distillation yield and LPG production objectives. This would be necessary to meet project export objectives because the refinery could not otherwise create enough propane and butane, and further would be driven by the enlarged revenue and profit streams from meeting those objectives.

Table 1. Post-project LPG production greatly exceeds refinery crude distillation yield

	Initial crude distillation yield[a]		Post-project LPG production[b]	
	% vol. on crude	barrels/day[c]	barrels/day	% of crude feed[c]
Propane	0.30–0.78	360–936	4,200	3.50
Butanes	1.35–3.31	1,620–3,970	9,300	7.75

(a) Median and 95th Percentile yields from 205 publicly reported crude oil assays (see Crude Assays).
(b) Total post-project production for export sales based on capacity reported (DEIR at 3-21).
(c) Calculated based on reported crude capacity of 120,000 b/cd from *Oil & Gas Journal* (2012).

15. The DEIR does not disclose the change in crude feed quality that could result from the project. The configuration of this project and refinery requires coking for the additional LPG-rich byproduct gases to meet the project's production and profit goals. Installing a catalytic cracker[16] or repurposing a hydrocracker would entail capital or lost motor vehicle fuels production costs that make those options conflict with maximizing LPG export profits. The U200 delayed coker is the primary source of LPG-rich gases that cannot be treated adequately by DGA (amine) processing; the project would "[i]nstall to U200" hydrotreating to provide this treatment; and the new hydrotreater's proposed purpose in this project is to allow LPG to be recovered from coker gases.[17]

[16] The Phillips 66 SFR does not include a catalytic cracking process. See BAAQMD, 2013.
[17] Phillips, 2012b at 4; DEIR at 3-5, 3-12, 3-16, 3-21, 3-23/24/25, 6-4/5; Phillips, 2012a at 5.

Delayed coking is severe thermal cracking (415–515 ºC at 15–90 psi for ≈24 hours) that is used to crack the densest oil streams processed, such as the residue from vacuum distillation of atmospheric distillation bottoms and bitumen.[18] Thus, the project would commit the refinery to continued coking of the highest-density part of the crude resource.

16. Importantly, denser coker feeds produce more gases and more LPG. Coking converts dense components of crude into oil streams that can be processed further to make light liquid fuels.[18] Named for its petroleum coke byproduct, it also creates byproduct gases with 1–4 carbon atoms (C4–), including butanes (C4) and propane (C3), which are burned as refinery fuel or, especially in the case of C3 and C4, sold as LPG.[19] Along with temperature, pressure, and reaction time, key process variables include feedstock properties and product targets.[20] Data summarized in Table 2 suggest that even at full coker capacity,[21] producing 8,000 b/d of LPG from refinery coker gases could require running the densest vacuum residues. Though it shows estimates only for a few possible feeds, Table 2 illustrates how, by adding an LPG export objective to its coker output, the project will drive the refinery to coking higher density feeds.

Table 2. Denser feeds increase C4– (including LPG) yield from delayed coking

Vacuum resid feed			
cut point (ºC)	+482	+538	+538
density (kg/m^3)	952–981	1,013	1,044
sulfur content (% wt.)	0.50–0.60	3.40	5.30
C4– (including LPG) yield			
C4– yield (% vol.)	10–11	15	17
***C4– yield at 47 kbpd coker capacity* (b/d)**	4,700–5,310	6,880	7,930

C4–: hydrocarbons with 4 carbons or less; LPG (butanes and propane) and lighter gases.
Data from tables 7.1-2 and 7.1-6 in Meyers, 1986. C4– overestimates LPG yield. Yield converted from mass to volume assuming all C4– is LPG with 539 kg/m^3 density, and 967 kg/m^3 density coke.

[18] See Meyers, 1986; Speight, 1991. Heavy or aliphatics-rich synthetic crude oils (SCOs) derived from partially pre-processing tar sands bitumen or crude residua may be included in these coker feeds, and refiners have sometimes labeled such SCOs as "gas oils," but calling them gas oil in this context is misleading. The DEIR does not disclose the project's reliance on low-quality oils.
[19] Delayed coking byproducts also include mercaptans and olefins (Meyers, 1986), which the new hydrotreater would remove from coker gases (Phillips, 2012a). Mercaptans are highly odorous: the coker thus may be linked to the refinery's notorious odor problems. These coking byproduct contaminants appear to be the reason for the new hydtrotreater but are not named in the DEIR.
[20] See Meyers (1986) at 7-69. The DEIR does not disclose this project link to coker operation.
[21] 47,000 b/cd (*Oil & Gas Journal,* 2012).

17. Thus, the project's new commitment to coking denser oils in order to meet its LPG export sales objective would lock the refinery into a crude slate at least as dense as, and likely denser than, its current slate. It likely would be denser because making more LPG would drive the refinery toward coking higher-density vacuum resid and bitumen and also toward increasing coker feed rates.[22] This would make denser vacuum resids, bitumen, or both a larger share of the crude slate, driving the density of the crude slate up.[23] Worse, it would do so during a period when the refinery almost certainly must switch—and in fact is beginning to switch—to new sources for its crude supply, as discussed in paragraphs 11 and 12. The project would thereby lock the refinery into a new crude slate of lower quality than it need otherwise choose. The DEIR does not disclose this effect of the project.

18. Contamination of refinery feedstock would increase as a result of the project. Sulfur and other toxic trace elements concentrate in the densest components[24] of crude that the imperative to produce more coker LPG would make a larger portion of the refinery's crude slate. Imports likely to dominate the new slate in order to fill SFR coking capacity—39% of its total feed volume[25]—with vacuum resid feeds as dense as the high-LPG feed shown in Table 2 could boost sulfur content substantially. See Table 3. Regional trends also support this expectation. See Chart 2. Indeed, sulfur in the new slate could reach ≈3–4.5% wt. The DEIR omits crude quality data,[22] but the crude feed is not nearly that high in sulfur now.[26] Available information suggests that the current average Rodeo feedstock is ≈915–918 kg/m^3 in density and ≈1–1.5 wt. % sulfur.[27] The crude slate resulting from the project likely would be denser and far more contaminated.

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[22] A separate environmental review of increased throughput rates reports some of the crude feed data that the DEIR should and could have reported, and reveals the company's plans to increase throughput rates for at least some of its upstream processing (see SMF EIR 2012 Excerpts). The DEIR does not mention or disclose this other proposed project or environmental review.
[23] The density of a crude oil is proportional to the volume of higher molecular weight, higher boiling point, larger hydrocarbons in that crude oil. See Karras, 2010; Speight, 1991.
[24] Sulfur, as well as nickel and vanadium, among other toxic elements, concentrates in the vacuum residua component of crude and bitumen. See Speight, 1991; Karras, 2010.
[25] SFR's 47,000 b/d of coking is 39% of its 120,000 b/d crude capacity (*Oil & Gas J.* data).
[26] Compare UCS (2011), ERM & BAAQMD (2012), *Oil & Gas Journal*, SMF EIR (2012) and EIA Imports Analysis: the Alaskan, imported, and San Joaquin (weighted average pipeline component) streams that comprise about three-quarters of Rodeo's slate have a combined average sulfur content of ≈1 wt. %: an average of 3% sulfur in this *current* slate is not plausible.
[27] UCS, 2011; ERM & BAAQMD, 2012; SMF EIR 2012.

Table 3. Selected data for crude oils with dense (≥ 1,040 kg/m^3) vacuum residue yield comprising ≈30–39% of the whole crude oil's total volume.

	DOE avg.[a] for these crude oils	Eocene[b] Crude (Mid-East)	Crude oils containing bitumen from tar sands[c] Access Western	Christina Dilbit Bld.	Surmont Heavy Bld	WCS*
Whole crude						
density (kg/m^3)	918	945	922	923	936	929
sulfur (wt. %)	2.98	4.57	3.94	3.80	2.99	3.51
TAN (mg KOH/g)	——	0.20	1.70	1.55	1.39	0.94
nickel (ppm wt.)	——	21	72	68	51	58
vanadium (ppm)	——	59	194	179	140	141
Vacuum residue						
volume (% crude)	34	34	36	36	29	37
density (kg/m^3)	1,060	1,070	1,062	1,059	1,061	1,054
sulfur (wt. %)	6.04	7.35	6.49	6.21	6.07	5.56
Vacuum Gas Oil & Residue combined						
volume (% crude)	53	68	61	60	56	63

*WCS: Western Canadian Select. (a) Data from the U.S. Dept. of Energy, Crude Oil Analysis Database: shown is the average of all data for crude oils with residue yields that are 30–39% of crude volume, and also denser than 1,040 kg/m^3 (n = 15). (b) Data from publicly reported assays of traded oils (Chevron, 2013). (c) Data from Canadian Crude Quality Monitoring Program. See Crude Assays; DOE COA 2013, attached).

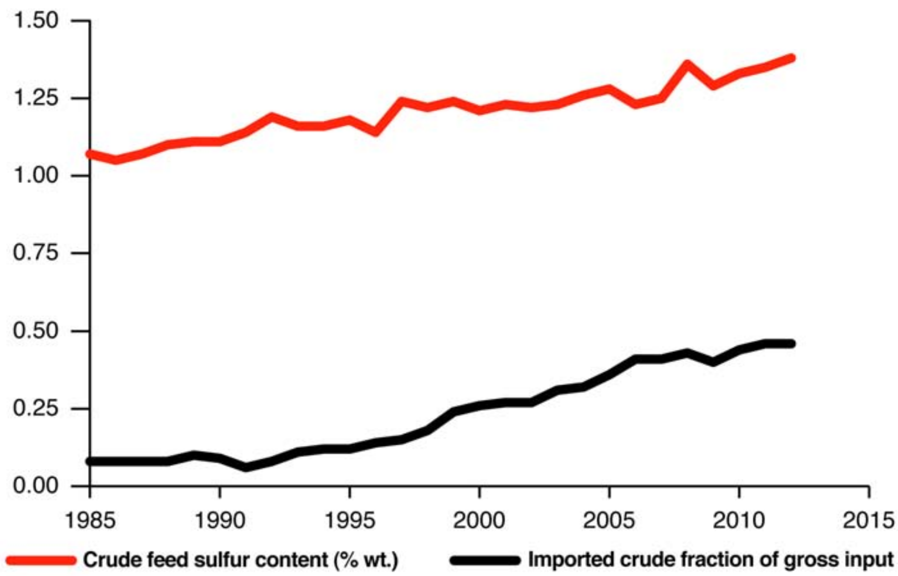

Chart 2. Sulfur and imports content of West Coast refinery crude feeds, 1985–2012
PADD 5 data from the U.S. Energy Information Administration (www.eia.gov/petroleum/data.cfm).

19. This new, dense crude slate likely will include more oil derived from "tar sands" bitumen. The project would commit the refinery to coker feed-rich crude over a period when the worldwide portion of high-density crude supplied by "heavy oil" and bitumen is likely to grow dramatically.[28] Bitumen has already come to dominate crude production in Canada,[29] the largest source of U.S. crude imports.[30] Moreover, crude can account for up to 90% of a refinery's operating costs,[31] and tar sands bitumen is price-discounted (due in part to delivery constraints),[32] so Phillips 66 is incented to run it, especially since the company's affiliates produce two of the bitumen blends shown in Table 3.[33] Indeed, recent major projects expanded the Rodeo facility's capacity to run more of these oils.[34] It now has vacuum distillation capacity to process a crude slate with atmospheric residua yield as high as 73% of the barrel, and coking capacity to process a slate with vacuum residua yield as high as 39% of the barrel,[35] which is more than enough to run the bitumen blends shown in Table 3.

20. Exactly what new crude blends to run is typically analyzed intensively based on many dozens of factors, but it is clear that the refinery will seek to run near capacity[36] and will continue to match blends of oils[37] to its processing capacities. Processing analysis for a blend of Western Canadian Select (WCS) and Alaskan North Slope (ANS) crude oils that the refinery could run is summarized as a hypothetical example in Table 4. In this simplified example, the refinery sells 12,000 b/d of the naphtha it distills from 120,000 b/d of WCS to other refiners, purchases 11,200 b/d of ANS gas oil, and runs its

[28] See Meyer et al., 2007. *Heavy oil and natural bitumen resources in geologic basins of the world.* U.S. Geological Survey Open-File Report 2007–1084; see also Kerr, 2009.
[29] ERCB st 98–2009. *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018.* Energy Resources Conservation Board, Calgary. See pp. 2–6; see also *Oil & Gas Journal,* 2007.
[30] EIA, 2013. (http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbbl_a.htm).
[31] *Interim Investigation Report, Chevron Richmond Refinery Fire.* U.S. Chemical Safety and Hazard Investigation Board. Adopted 19 April 2013. (CSB, 2013.) See page 33.
[32] See Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)
[33] See Canadian Crude Monitoring Program (www.crudemonitor.ca): Christina Dilbit Blend ("produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility"); and Surmont Heavy Blend (50% owned, and operated by, Conoco Phillips Canada).
[34] See Strategic Modernization SCH #2002122017; Clean Fuels Expansion SCH #200509028; Marine Terminal Offload Project (ERM & BAAQMD, 2012); and DEIR at 3-19/20, 5-4/5-7.
[35] Based on process vs. crude capacities reported as of 1/1/13 by *Oil & Gas Journal* (2012).
[36] U.S. refineries ran at 90% of capacity on average since 1990 (www.eia.gov/petroleum/data).
[37] In addition to California and Alaska, the SFR processed oils from Canada and 20 other countries during 2004–2012 (EIA Imports Analysis).

Table 4. Example SFR refinery crude slate blending tar sands and conventional oils.

Crude slate	Volume (b/d)	Density (kg/m^3)	Sulfur (wt. %)	*Oil source*
Total input processed*	119,184	952	3.40	
Naphtha (naph)	11,088	691	0.05	*Western Canadian Select (WCS)*
Distillate (dist)	21,096	880	1.22	*WCS*
Vacuum gas oil (gas oil)	31,188	954	2.97	*WCS*
Imported vacuum gas oil	11,184	929	1.20	*Alaskan North Slope (ANS)*
Vacuum residua (resid)	44,628	1,054	5.56	*WCS*

* *Excludes straight run (SR; from atm. distillation) naphtha exported (12,000 b/d).*

	Capacity (b/d)	Throughputs(b/d)					
Atmospheric distillation	120,000	WCS oils	108,000				
Vacuum distillation (VDU)	87,000	SR resid	44,628	SR gas oil*	42,372		
Delayed coking (DCU)	47,000	VDU resid	44,628	VDU gas oil	2,372		
Hydrocracking (HCU)	58,000	VDU gas oil	40,000	DCU gas oil	14,423	SR dist	3,577
distillate Hydrotreating	44,000	HCU dist	26,481	SR dist	17,519		
naphtha Hydrotreating	29,000	DCU naph	11,470	SR naph	11,088	HCU naph	6,442
Reforming	31,000	DCU naph	4,470	SR naph	11,088	HCU naph	15,442
Isomerization	9,000	DCU naph	7,000	HCU naph	2,000		

* *Includes ANS oil that bypasses atm. distillation (11,184 b/d).*

Sulfur balance: 613 tonnes/day enter refinery in crude
−145 t/d leaving refinery in coke
468 t/d recovered (82% of SRU capacity)

Crude quality data from Canadian Crude Quality Monitoring Program (www.crudemonitor.ca) and publicly reported assays for ANS crude (*Oil & Gas Journal;* ExxonMobil and BP web sites). Refinery process capacities as of 1 January 2013 from *Oil & Gas Journal* (2012). Delayed coking yield based on typical yield reported for dense (1,044 kg/m^3) vacuum residua feed (see Tables 7.1-2 and 7.1-6 in Myers, 1986) and typical North American petroleum coke density (see Table S5 in Karras, 2010). Internal refinery hydrocarbon flow volumes may vary with varying volume expansion/loss effects in conversion processing. Capacities shown include the company's Santa Maria operations, which are integrated with the Rodeo operations via transfers of intermediate products, facilitating import/export logistics for refinery input blending.

vacuum distillation, coking, hydroprocessing, reforming and isomerization units at full capacity on the resultant WCS/ANS blend. This hypothetical example assumes WCS delivery, and represents but one of perhaps thousands of blends that the company might analyze closely for feedstock performance and cost containment. Nevertheless, this example shows that a new tar sands-derived crude slate could be very dense (≈952 kg/m^3) and high in sulfur (≈3.4 wt. %).

21. Crucially, logistical costs of bringing tar sands oil into the refinery—while rail loading, pipeline, and pipeline-to-boat capacities remain bottlenecked[38]—emerge as a

[38] See Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)

barrier to processing much more tar sands oil at the San Francisco Refinery. By linking a major new profit stream from LPG sales to price-discounted coker feeds such as bitumen, while expanding total rail and wharf loading capacity, the project could breach this transport cost barrier, and increase tar sands crude inputs to the refinery.

22. A Phillips 66 web page presents a map depicting crude transport routes from the tar sands region of Canada to its SFR by rail, pipeline, and ship, and quotes Chairman and CEO Greg Garland among the following excerpted statements:

> "Advantaged crude sells at a discount relative to crude oils tied to the global benchmark … [and] include[s] heavy crude from Canada …
>
> 'We are looking at pipe, rail, truck, barge and ship—just about any way we can get advantaged crude to the front end of the refineries,' said Garland. …
>
> The next challenge for the company is identifying strategies to get more advantaged crude oil to its California refineries [which can run a wide range of crudes]."[39]

Separately, Garland disclosed that the company's "opportunity to improve performance in California is really around getting advantage crudes to the front end of the California refineries, its rail, its ship, it's *working on optimization of the cost structure and the export capabilities of those refineries.*"[40] (Emphasis added.) These disclosures support the evidence discussed in paragraphs 12–21 and shed some light on how expanding rail capacity, production capacity, and LPG sales revenue in a way that is locked into low-quality crude feeds could "optimize the cost structure" for getting cheap tar sands oil to the refinery. The DEIR omits these disclosures.

23. Among other problems, denser and more contaminated crude feeds can greatly increase refinery energy intensity, air emissions, toxic pollutant releases, flaring, and catastrophic incident risk. The DEIR does not disclose or describe these impacts.

24. Changes in the fuel burned to heat, pressurize, and power refinery process equipment that would result from the project are not described adequately in the DEIR. It acknowledges a substantial shift in fuels to be burned but does not report the chemical composition of the current mixture of gasses burned or the changed mixture to be

[39] See: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx.
[40] Thomson Reuters DECEMBER 13, 2012 / 01:30PM GMT, PSX – Phillips 66 First Annual Analyst Meeting. (www.streetevents.com).

burned. Some of this fuel gas composition data is available,[41] but it is not included in, or analyzed by, the DEIR. The mixture of chemicals burned must be identified and analyzed to support complete and reliable estimates of project air emissions.

25. Similarly, as the project causes the refinery to burn more fuel for energy it lowers the fuel's heat content, changing combustion conditions when it is burned. The DEIR provides no information about changes in the equipment that would burn this changed fuel refinery wide. For example, it is troubling that the company first asserted the lower heat content of refinery fuel gas "will require alterations to the burners of 19 heaters to operate efficiently," but now asserts that "no changes to any burners are required at this time," without providing design capacity data for its burners requested by air officials.[42] The DEIR does not mention this issue or correspondence, but this type of data on combustion equipment that could be affected by project fuel changes must be reported and analyzed to support a complete and reliable analysis of project impacts on flaring.

26. The DEIR does not disclose a part of the project that would enable emission increases that could cancel out its claimed SO_2 emissions reduction. Phillips 66 seeks "emission reduction credits" that could be banked and then used later, allowing the refinery to increase emissions by the credited amounts. In its application for air permits submitted for this project eight months ago, the company references the SO_2 emission reduction associated with the project that also is asserted in the DEIR, and then states:

> "Phillips 66 requests 174.7 tons per year of SO_2 emission reduction credits (ERCs) for this reduction. Of this amount, 7.61 tpy will be used to offset project SO_2 increases so that there will be no net increase in SO_2 emissions from the project (see Table 3-1). The remaining 167.1 tpy of SO_2 (174 tpy minus 7.61 tpy) will be banked as ERCs."[43]

This part of the project, to increase emissions later, and this "no net increase" claim, contradict the DEIR's unqualified assertion that the project will result in reducing refinery wide SO_2 emissions "by at least 50%."[44] The DEIR does not propose any condition of approval requiring that the promised refinery wide emission reduction be

[41] See project Air Permit Application attachments A-4 and A-7 (Air Permit App Atts A 4 & 7).
[42] See Phillips' letters of 30 April 2013 (page 1) and 28 June 2013 (page 14) responding to BAAQMD letters of 1 March and 21 May, 2013 advising that its air permit application for the project is incomplete, and presenting numerous data requests (Air Permit Correspondence).
[43] Air Permit Application at 17, Section 3.4 (Air Permit App Sections 1–3).
[44] DEIR at ES-2, 3-5, and 4.3-19.

permanent. It does not identify the now-apparent link, between undisclosed future activities, and this project that could allow those future activities to pollute. It does not evaluate what those activities entail, whether they are part of the project or related to it in other ways as well, why the future rebound in emissions seems necessary, how soon it might occur, or how long it might last. Omitting plans to enable emissions that the DEIR is at the same time asserting will be cut appears misleading. In any case, this part of the project conflicts with the project objective to reduce emissions that is stated in the DEIR.

27. Waste heat from burning fuel to operate the project would be transferred to San Francisco Bay by expanding "once-through cooling" (OTC) that sucks Bay water into the refinery and discharges it back to the Bay as thermal waste. The DEIR does not report how much more heat the project would dump into the Bay. Moreover, its analysis of Bay water use, which *should* indicate the extent of thermal and other impacts of the OTC expansion, underestimates the potential increase in OTC water and heat flows.

28. According to the DEIR, the OTC expansion to 57.6 million gallons/day (MGD) represents an increase of 12.2 MGD from a project baseline OTC flow of 45.4 MGD.[45] The DEIR asserts this 45.4 MGD baseline without any supporting documentation, but NPDES findings omitted from it show that average OTC flow never approached 45.4 MGD since at least 1985. <u>See</u> Chart 3. Further, the refinery was required to estimate impacts of related prior modifications on its OTC flow and estimated they would increase it to only ≈35.4 MGD.[46] Permit review analysis of post-modification continuous monitoring data to check on that estimate found OTC flow of ≈35.5 MGD in 2010, and by mid-2011 this monitoring showed a long-term average OTC flow of ≈38.3 MGD.[46] This evidence shows that the 45.4 MGD DEIR estimate inflates the project's OTC baseline. Based on the proposed OTC expansion to 40,000 gpm (57.6 MGD) and the most recent NPDES long-term average OTC flow (38.3 MGD), the project could use ≈19.3 MGD of Bay water. This more accurate OTC flow increment (19.3 MGD) exceeds the increment the DEIR calculated from its inflated baseline (12.2 MGD) substantially.

[45] DEIR at 3-27; <u>see</u> also Phillips, 2012b at 23–24: The same 40,000 gpm post-project total and 8,500 gpm increase on a purported 31,500 gpm baseline is asserted without documentary support in both, but 40,000 gpm is the proposed OTC rate that would be implied by project approval.
[46] NPDES Permit R2-2011-0027 at F-53 and Finding II. B. 3; <u>see</u> also Table E-5.

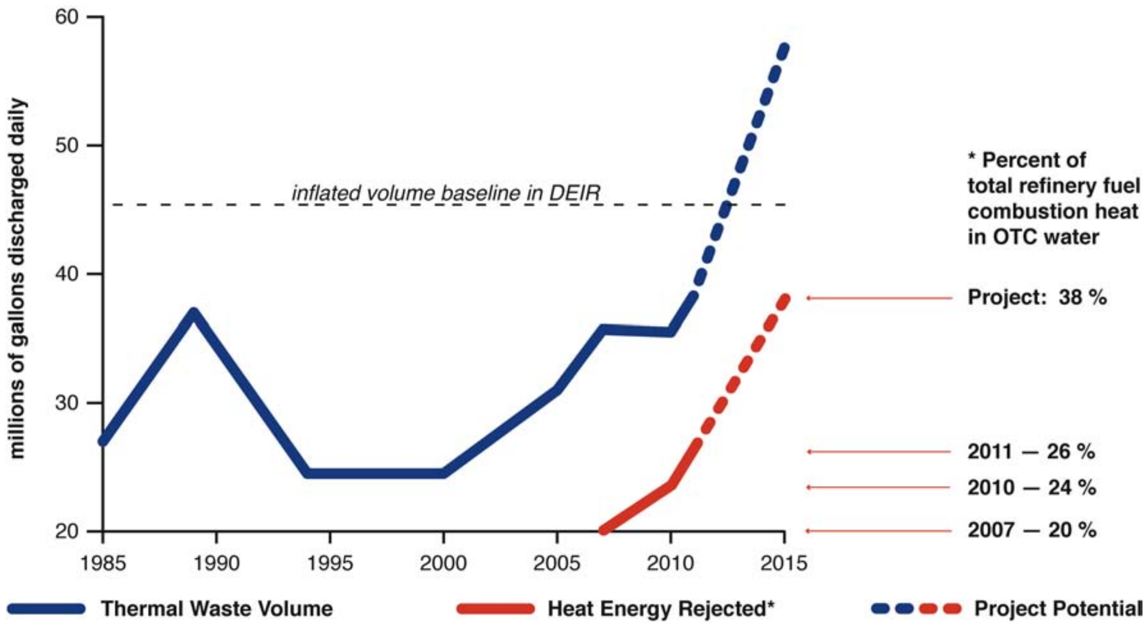

Chart 3. Rodeo facility combustion heat transfer to S.F. Bay. Thermal waste 1985–2011 volume data from NPDES orders R2-1985-029, 1989-002, 1994-129, 2000-015, 2005-0030 and R2-2011-0027; project potential volume from DEIR. Heat energy rejected is shown as a percentage of total refinery fuel energy (DEIR tables 4.6–1, 4.6–2) and is estimated based on volume entering OTC at 55 ºF (Reg. Monitoring Program, Davis Pt. Oct–June avg.) and exiting processing at 110 ºF before heat loss to the atmosphere and mixing in the retention system upstream of the outfall, and the specific heat of water (4.1868 J). Project potential heat percentage based on 2011 fuel use plus 140 MMBtu/hr for project steam.

29. Total heat rejected by OTC would grow, from ≈6.3–6.8 million gigajoules/year during 2007–2011 to ≈10.2 MM GJ/yr as a result of the project.[47] Waste heat rejected by the project flow increment (≈3.4–3.9 MM GJ/yr) would greatly exceed the total energy of additional fuel the DEIR states the refinery could burn for the project (1.23 MM GJ/yr).[48] Consequently, refinery wide reliance on OTC to reject waste heat would grow, from ≈20–26% of all fuel energy burned in the facility during 2007–2011, to ≈38% of post-project refinery energy use.[49] See Chart 3. The DEIR does not identify or explain the discrepancy between the fuel it says the project would burn and the heat its expanded OTC could carry, and it does not disclose this increased refinery wide reliance on OTC.

[47] 1 gigajoule (GJ): 1 billion joules; 0.994 MMBtu. Waste heat rejected estimated as summarized in the caption of Chart 3. Note that the DEIR does not report the temperature of water exiting processing before entering the retention basin and mixing with other flows around the splitter; it states only that heat loss in those upstream steps will keep the OTC discharge at E-002 ≤ 110 ºF.
[48] Based on 140 MMBtu/hr expanded steam boiler capacity (see DEIR at 3-20; 3-21) at 100% utilization. Note that even the DEIR's underestimated OTC flow (≈2.16 MM GJ/yr) would reject more heat than this expanded boiler firing would add: the DEIR does not identify the discrepancy.
[49] Based on annual fuel use in DEIR at 4.6-2, and project adding 140 MMBtu/hr to 2011 fuel use.

30. This increased reliance on OTC to carry heat from as-yet unidentified sources is consistent with an undisclosed increase in firing rates to process denser, higher sulfur crude feeds—which are known to increase refinery energy intensity.[50] It is consistent, also, with a shift from existing cooling towers to OTC—which might yield savings on cooling tower makeup water and chemicals.[51] Confirming or quantifying either or both possibilities may require cooling system design information that the DEIR does not provide. Regardless of its specific uses in cooling the refinery, however, the project's expansion of OTC would conflict with ongoing efforts to phase out and replace OTC.

31. In 2010 California adopted the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.[52] Among other things, this policy required power plant cooling systems to reflect the best technology available, encouraged them to use recycled water instead of estuarine water, and required most plants to cease OTC for units "not directly engaged in power-generating activities or critical system maintenance" by October 2011.[52] Importantly, oil refining is not addressed specifically by this policy at least in part because most California refineries replaced OTC with "closed loop" cooling towers long ago. In fact, the Rodeo facility is the only one of the five refineries lining the Bay that still uses this antiquated cooling technology[53]—and it has been since the Richmond refinery phased out and replaced OTC in the 1980s. The DEIR does not discuss this crucial context.

32. Work that could lead to phasing out and replacing OTC at the refinery has been ordered by the California Regional Water Quality Control Board. The Board ordered the refinery to prepare an engineering evaluation of replacing OTC, including a "conceptual design for a closed loop cooling tower system, including estimated costs (capital and operation) and construction timetable."[54] Phillips' 2012 response reported locations where two cooling towers could be built to replace OTC, conceptual designs for them, and estimated capital ($50 MM) and operating ($5.5 MM/yr) costs.[51] For context, this estimate suggests that the annualized cost over ten years represents only 0.2–0.3 % of the refinery's annual cost for $75/b–$115/b crude. The DEIR does not include or discuss this state order to evaluate replacing OTC or this refinery report indicating it can be done.

[50] See Karras, 2010; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson, 2012.
[51] See *Cooling Tower Replacement Feasibility Evaluation* (Phillips Cooling Tower).
[52] As adopted by the State Water Resources Control Board on 1 October 2010 (SWRCB, 2010).
[53] Chevron R2-2011-0049; Shell R2-2012-0052; Tesoro R2-2010-0084; Valero R2-2009-0079.
[54] NPDES Permit R2-2011-0027 at Provision VI.C.2.f.

33. Evidence discussed in paragraphs 27–32 indicates that, by building onto and expanding the existing OTC system at the refinery, the project would foreclose an opportunity to replace OTC in the near term, and would instead continue and expand the use of this antiquated cooling technology. It would thereby result in the continuation of adverse impacts on aquatic life in San Francisco Bay that could otherwise be eliminated, in addition to the impacts from project increases in OTC flows. However, the DEIR seeks to evaluate only impacts from its (under)estimate of the increased OTC flow rate, further underestimating the project's potential impacts on the Bay.

34. Once-through cooling harms aquatic ecosystems by injuring or killing biota and degrading their habitats via entrainment,[55] impingement,[56] and thermal pollution.[57] In operation at design temperature, the severity of system- and site-specific impacts is generally proportional to OTC flow. Clearly adverse impacts have been documented from entrainment and at shoreline thermal discharge sites in San Francisco Bay,[58] but monitoring studies have yet to measure the full ecological impact of site-specific OTC applications. This is in part because of practical limitations in scientific tools. For example, reviews of a series of Bay OTC impact studies[59] found:

- Sampling techniques can be too aggressive for some species that become mutilated and unidentifiable or too passive to capture and account accurately for other species.
- Perceptions about the cost of comprehensive sampling lead to excluding many species or life stages—such as phytoplankton, invertebrates, eggs, and species present in very low abundance—and to attempts to measure "surrogate" species instead.
- Similarly, multi-year sampling is seldom done, but interannual variability changes the occurrence and abundance of many species affected by OTC in estuaries like the Bay.
- Sampling and data management designs must anticipate seasonal and spatial variation in the abundance of various species and life stages, but the site-specific timing of such changes is difficult to predict in many cases and may be impossible to predict for some poorly studied species.

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[55] The organism enters into the cooling system with water drawn through the intake screens.
[56] The organism is held against the intake screen by the force of the water flowing into the plant.
[57] Habitat is degraded or lost to various species when the ambient water temperature rises locally.
[58] For example, Mirant Corp. expected aquatic plant and invertebrate species to rebound if its Potrero power plant's thermal discharge was removed from a shoreline outfall (*Construction and Thermal Impacts First Quarter Larval Fish Assessment, 2001-2002*), and entrainment in the 226 MGD Potrero OTC flow was shown to kill an estimated 241–321 million larval fish annually (CBE, 2006). Impacts from the project's 57.6 MGD flow may be different from those of that different OTC system in another part of the Bay, and lesser or greater proportionate to its flow.
[59] See CBE, 2006.

- Taxonomic identification, especially in samples with small numbers of nonabundant or mutilated organisms among large numbers of another species, requires judgment.
- Rates of survival to reproductive age for larvae or juveniles affected by entrainment are generally not measured directly, and are instead inferred from generalized life history data that may be inaccurate or incomplete for certain species or populations.
- Indirect impacts, such as those from loss of forage (food supply) for another species, may be significant, but are difficult to measure and generally are not measured.
- Undersampled species may disproportionately affect the ecological system studied.
- Measurement limitations—such as those mentioned here as well as sampling losses and other anomalies—must be tracked and interpreted in analysis of the data.

Thus, OTC impact studies involve many judgments that are ultimately subjective and yet may determine whether impacts are detected. Compounding the problem in another way, these studies are typically sponsored by plant operators who prefer to avoid replacing OTC. For these reasons, the best practice standard for environmental review of OTC impact monitoring studies includes some form of independent peer review during study design, study implementation, and interpretation of study results. The DEIR does not identify any of these limitations in biological monitoring studies of OTC.

35. No description of the biological effects of OTC *expansion* is provided in the DEIR. Its full discussion of biological effects from the OTC system itself—except for admitting that endangered species are at increased risk of adverse impact—is one long sentence about an old study of intake impacts:

> "The Refinery documented the effectiveness of the wedgewire screens in 2006, estimating that their configuration virtually eliminated impingement of adult and juvenile fishes and significantly reduced entrainment of larval fishes; the location of the intake structure provides effective sweeping flow velocities that, combined with low through-screen velocities at maximum pumping rates, minimize the entrainment of larval fishes."[60]

The DEIR thus does not discuss the extent to which this study: measured all potentially impacted species; used sampling techniques that were effective for all species targeted; identified all targeted species in each sample accurately; monitored or accounted for the great interannual variability of the estuarine impact zone; captured seasonal and spatial variability in OTC impacts; measured long-term survival of entrained or impinged biota and indirect impacts such as forage reduction on other species; measured effects on non-abundant species present, or made proper judgments about these issues in data analysis.

[60] DEIR at 4.4-27. A thermal impact study is not yet done: see Phillips thermal ext 1, 2.

The DEIR does not actually say whether this study collected *any* biological samples. Moreover, this study of 2006 OTC flow conditions does not represent the project's potential for much greater long-term future OTC flow conditions. See Chart 3. The DEIR obscures this important fact by its false assumption that only its underestimated flow increment (12.2 MGD), rather than the full post-project OTC flow (57.6 MGD), should be assessed for potential impacts. The project would increase OTC flow more than the DEIR's inflated baseline discloses *and* would cause the full expanded OTC flow to continue when it otherwise could be eliminated, as discussed in paragraphs 27–33. Accordingly, this 2006 study, and the DEIR itself, does not describe the biological implications of the expanded OTC flow that would result from the project.

36. Instead of describing these environmental implications of the project, the DEIR asserts that any impacts from the OTC expansion will be less than significant because of NPDES permit limits.[61] This assertion is contradicted by facts that the DEIR does not disclose, but in a vain attempt to support it, the DEIR makes a series of erroneous statements that describe the project and its setting inaccurately. In a paragraph referring to an allowable "maximum discharge temperature of 110 ºF" the DEIR asserts:

> "By using sufficient cooling water to ensure that maximum temperatures remain in compliance with the NPDES permit, no significant impacts on special-status fishes would occur."[62]

This statement is clearly erroneous because a large enough volume of 80–110 ºF thermal waste would injure or kill fish that are adapted to 55 ºF water,[63] but it also is misleading. This statement only makes sense if the heat in the 57.6 MGD discharge diffuses rapidly. The statement thus invites the inference that the Rodeo OTC discharges via a deepwater diffuser—a technology so universally required that a proper environmental review would surely note the anomaly if that was not the case—but that is not the case. The antiquated OTC discharges from a shoreline outfall. See Map 1 discharge point 003. Consequently, the thermal waste receives little or no initial dilution, greatly exacerbating its localized impact, and NPDES permit limits allow that, but the DEIR does not disclose these facts.

[61] DEIR at 4.4-27 and 4.4-28; see also DEIR at 4.10-24. It is acknowledged that deferring to future actions by others to address impacts has serious policy and legal implications that require analysis beyond the scope of this report.
[62] DEIR at 4.4-28.
[63] This water temperature (≈55 ºF) is typical in the ambient water of San Pablo Bay near the OTC outfall. See Regional Monitoring Program, Oct–Jun average for Davis Point (Site BD40).

Map 1. Rodeo facility outline, discharge points, and intake points. Attachment B to NPDES Permit, Order R2-2011-0027. The left-most circle containing a cross denotes discharge point E-003.

37. Compounding its error, the DEIR further explains its reliance on NPDES limits by asserting that “the NPDES permit establishes maximum once-through volumes.”[64] This statement is untrue. The permit limits several pollutants in the OTC thermal waste discharge at outfall E-003 but flow volume is *not* limited by this permit.[65] The 56% increase in OTC flow during 2000–2011, a period when two permit orders document concerns over OTC impacts that remain unresolved,[65] demonstrates the fallacy of the DEIR’s flow limit assertion poignantly. <u>See</u> Chart 3. The DEIR’s misplaced focus on permit limits also obscures the permit’s ongoing effort to develop closed loop cooling to replace OTC and eliminate its impacts—a crucial effort that the project would foreclose.

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[64] DEIR at 4.4–23; <u>see</u> also 4.4-27.
[65] All NPDES permit limits on the OTC (E-003), for ºF, TOC, Cl, Cu, Ni, Zn, and dioxins, are given in tables 8–11 of NPDES Permit Order R2-2011-0027, and flow volume is <u>*not*</u> among them. Provisions VI.C.2 d–f of this Order, and provisions D.9 and D.10 of Order R2-2005-0030 document ongoing, unresolved concerns regarding impacts of the OTC during this period.

38. Remarkably, the DEIR admits that the project's expansion of once-through cooling has the potential to adversely impact threatened or endangered fish species without specifying which ones. It states: "[S]pecial-status fish species identified in Table 4.4-1 that may be present along the Refinery shoreline on a seasonal or year-round basis … are potentially at risk of being entrained in intake pipes, and this risk could increase due to the increased volume of once-through water that would be required under the Project. … . These fishes [also] could be subjected to an increased risk of injury, death, or habitat reduction at effluent discharge locations"[66] The DEIR defines "special-status fish species" to include, among others, the Southern DPS–Green Sturgeon, the Central California Coast and Central Valley DPS–Steelhead, the Central Valley Spring-run Chinook Salmon, and the Winter-run Chinook Salmon—all federally listed threatened or endangered species.[67] The severity or importance of this potential impact may depend in part upon which of the endangered or threatened species face this project risk, but the DEIR does not provide that information, or at least does not do so in an easily understandable form.

39. LPG taken from cracking byproduct gases and treated in the refinery would be stored in new propane and existing butane tanks before loading to railcars via two new rail spurs and a new two-sided loading rack, according to the DEIR project description.[68] The DEIR acknowledges that although this occurs very rarely, the potential exists for a catastrophic failure of an LPG storage vessel such as a "boiling liquid expanding vapor explosion."[69] However, the DEIR describes it as occurring too rarely to warrant analysis of mitigation, and describes cooling the LPG storage tanks instead of pressurizing them (which would eliminate this catastrophic risk) as "infeasible" because of the added costs for electricity and a new flare.[69] Impacts of such an incident could be catastrophic and irreversible. The DEIR does not include or describe the documented Process Hazard Analysis or Inherently Safer Systems Evaluation required by the County Industrial Safety Ordinance (ISO) for the project, and thus does not disclose that those requirements contradict its analysis.

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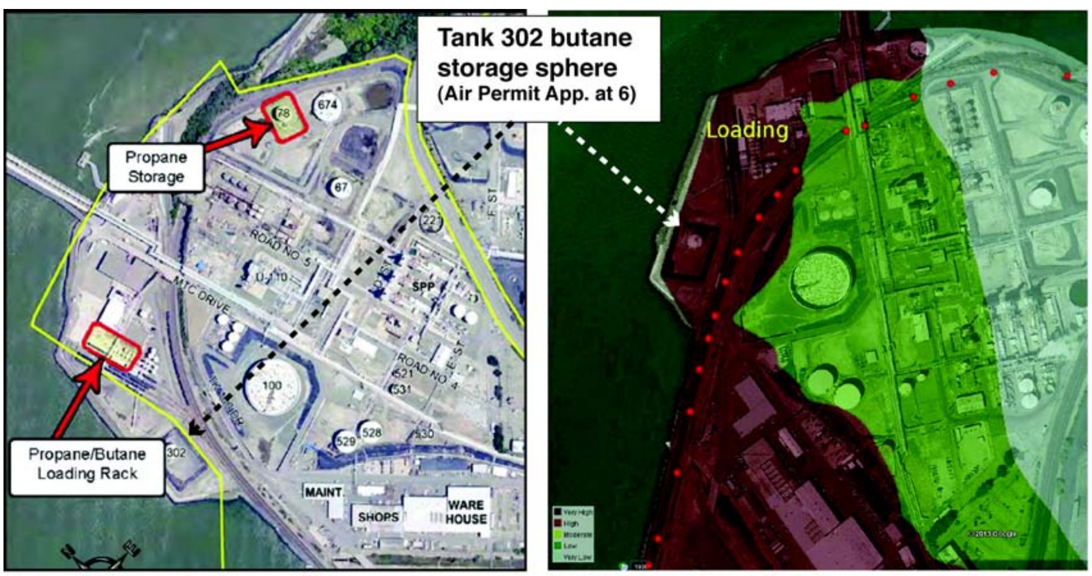
[66] DEIR at 4.4-27. The quote continues, with a qualifier regarding the thermal impact reading *"if those temperatures exceed permitted discharge limits."* However, the DEIR wrongly assumes the increased volume of hot shoreline discharge that receives little or no dilution is controlled by permit volume limits and will not impact the fish, as discussed in paragraphs 36 and 37.
[67] DEIR at 4.4-9 and 4.4-10 (Table 4.4-1).
[68] DEIR at 3-6, 3-17, 3-21 and 3-25.
[69] DEIR at 49-2, 4.9-18, 4.9-19 through 4.9-22, 6-5.

40. Process hazard analysis (PHA) requires, among other things, rigorous determination of the site-specific likelihood of particular hazardous consequences.[70] "Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process."[70] For example, a comprehensive PHA for the project's new propane and additional butane storage would identify and analyze the increased probability of catastrophic failure caused by soil liquefaction in an earthquake—a serious site-specific risk in the seismically active East Bay. At least one of the tanks that would store project LPG is sited on a shoreline plot[71] at high risk for soil liquefaction. See Map 2. This would increase the probability of catastrophic failure involving LPG storage over time. The DEIR, however, estimates this probability based on generalized industry-wide estimates of its frequency.[72] Because it does not describe or evaluate the site-specific conditions, the DEIR underestimates the probability of a catastrophic event.



A. Detail from DEIR Figure 3-3.
B. Seismic shaking / liquifaction hazard overlay

Map 2. Project-related LPG storage near loading, and earthquake liquefaction hazard
Note the two plate's different orientation to North. Plate B from Ed Tannenbaum and Danielle Fugere.
Burgundy shading in the area near the shoreline (Plate B) indicates very high liquefaction hazard.

[70] CSB, 2013 at 40; see also CSB at 32.
[71] Project butane would increase this and other tanks' throughput. DEIR at 3-21/26, 4.5-7, 4.9-1.
[72] DEIR at 4.9-18; see also AICE, 1989 at 205.

41. County Hazardous Materials Program staff have informed Phillips 66 that they expect "revised siting studies with placing new equipment and associated impacts to existing processes including locations that house personnel (e.g., control rooms, admin buildings)" for the project.[73] These studies would detail what comparing maps 1 and 2 shows: Project-related LPG storage is located relatively close to a concentration of other vessels containing flammable hydrocarbons, the administration building, parking lots, and thus numerous plant personnel. However, the DEIR describes only "moderate" consequences of a catastrophic LPG storage incident, and explains that this is "primarily due to the large distances to the *off-site receptors* (730 to 1340 m.)."[74] *(Emphasis added.)* Its incomplete description of the project's setting causes the DEIR to ignore workers and underestimate the magnitude of this catastrophic risk.

42. Cooled instead of pressurized liquefied gas storage could eliminate the risk of catastrophic LPG storage vessel explosion. Because it is practicable and safer than the proposed pressurized storage for this identified catastrophic hazard, cooled storage could be defined as an inherently safer system with respect to this hazard. In contrast to the DEIR's failure to analyze this mitigation, the ISO *requires* documented inherently safer systems analysis for new processes and facilities.[75] The U.S. Chemical Safety Board recommends that inherently safer technology should be implemented to drive risk as low as reasonably practicable (ALARP), and notes that: "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process … rather than after the process is already operating."[75] Furthermore, in contrast to the DEIR's description of cooled storage as "infeasible" due to the costs of additional electric power and a new flare, the ISO seeks to implement inherently safer solutions "to the greatest extent feasible."[75] There is no cost exemption for affordable cooled storage. The DEIR's description of catastrophic hazards is in error, and its failure to describe inherently safer systems requirements for the project obscures this error.

43. CHMP staff also expect documented human factors evaluations of processes and procedures for the project.[73] These could include, among other things, evaluation of "safety culture" problems that may incent company management to defer safety measures

[73] 11 July 2013 letter from Michael Dossey to Jim Ferris, Phillips 66 (CCHMP–Phillips). The DEIR does not include these process-specific studies or evaluations or discuss their results.
[74] DEIR at 4.9-21.
[75] ISO § 450–8.016(d)(3); see also CSB, 2013 at 40, 45–47, and 55. The DEIR does not include or discuss the Chemical Safety Board's findings, or even its recommendations to the County.

as a shortsighted way to cut costs.[76] But the DEIR does not include or report on this human factors evaluation, and although it is relevant, the DEIR does not discuss this safety culture issue. Chevron management deferred at least six worker requests to inspect or replace a piping circuit over ten years, before that severely corroded pipe ruptured catastrophically in the 6 August 2012 Richmond refinery fire.[77] In another example of poor safety culture, the BP Texas City refinery explosion in March 2005 killed 15 people and injured 180 after BP management—in part to boost profits by avoiding short term costs—deferred replacement of a blowdown stack with a flare.[78] Similarly, the DEIR assumes a bias in favor of avoiding the cost of a flare in its inappropriate failure to analyze identified mitigation for a catastrophic hazard presented by the project.

44. Chemical spills, fires, and explosions at U.S. oil refineries killed at least 30 and injured at least 15,211 workers and nearby residents since 1999.[79] At least 49 upset "emergency" incidents occurred at Bay Area refineries since March 2010.[80] At least 30 such incidents occurred at California refineries in a recent five-month span.[81] The DEIR does not describe or discuss this important context for review of project hazards.

45. Exporting 8,000 b/d of additional LPG from the refinery for sale instead of burning that propane and butane in its fuel gas would change the location of emissions from LPG created by refinery processes. Although selling this LPG for purposes that obviously include burning it is the primary objective the DEIR states for the project, the DEIR does not identify or describe the resultant off-site impacts or provide information about specific end uses of this LPG.[82] Those potential emissions are substantial: the

[76] Chevron Safety Audit Oversight Committee, 2013. Audit Scope of Work.
[77] CSB, 2013: see esp. 36–42.
[78] Chemical Safety Board incident investigation (CSB, 2005). See esp. page 253: In one instance BP managers decided on in-kind replacement of the hazardous design in part to "maintain profits" by avoiding new source standards that likely would have required connecting to a flare.
[79] U.S. Chemical Safety Board incident investigation reports (www.csb.gov). Injuries include hospital visits associated with the 2012 Chevron Richmond refinery fire.
[80] Flare causal analyses submitted to Bay Area AQMD pursuant to Rule 12-12, §406.
[81] Labor Occupational Health Program, U.C. Berkeley, 2013 (LOHP).
[82] BAAQMD asked for the end uses of this LPG but like the DEIR, the company did not report them (see Air permit correspondence). Because of this nonreporting only a "potential to pollute" estimate is possible, but it is reasonably foreseeable that virtually all project LPG exports could be burned. Combustion activities (residential, C4 gasoline addition, industrial and recreational) are the primary end use of LPG sold nationally, and markets are highly regional; LPG use for petrochemical feedstock is highly concentrated in the Gulf Coast. Shipping costs to sell Rodeo LPG in the Gulf Coast would make it less competitive than Gulf Coast LPG supplies.

DEIR estimates that the LPG the project would remove from refinery fuel gas would emit greenhouse gases (GHG) at a rate of 759,244 tonnes/yr.[83] But instead of identifying, describing, or accounting for the resultant off-site impacts, the DEIR subtracts this amount from its project GHG emission estimate. The DEIR thereby assigns offsite LPG emissions a value of zero—even though it accounts for project emissions from outside the refinery gate for transport, and electricity generation—erroneously calculating a net decrease in GHG emissions (–325,978 tonnes/yr) when the correct net emissions, by its own estimate, total 433,266 tonnes/yr (–325,978 + 759,244).[83] Thus, project emissions could exceed the 10,000 tonnes/yr threshold of significance for GHG emissions used by the DEIR substantially. The DEIR does not identify a potential impact that would be significant, in part because it does not describe LPG environmental implications of achieving the project's main stated goal outside the refinery gate.

46. Byproduct coke production would increase along with cracked LPG gases for the project, but the DEIR does not say how much, or whether this additional petroleum coke will be exported, burned in the refinery, or both. Increased coking of denser feeds might increase coke production by thousands of barrels/day, and coke burns much dirtier than the gases the DEIR assumes the refinery will burn.[84] Burning the extra coke created by the project in place of other refinery fuel could increase refinery emissions substantially.

47. The DEIR does not explain that the company's Rodeo Facility (RF) and Santa Maria Facility (SMF) are two parts of one integrated refinery. The SMF and RF are linked by a pipeline sending crude and intermediate oils between them,[85] their processes are integrated to a capacity that neither can achieve alone,[86] and Phillips 66 reports them as a single processing entity to industry and government monitors[86] that is called the "San Francisco Refinery."[85] Omitting all of this, the DEIR also fails to explain the extent to which this project, and the concurrent SMF expansion to increase production and pipeline shipments to Rodeo,[85] are two parts of a single, larger, project that remains undisclosed.

[83] See DEIR at 4.8-18, Table 4.8-3
[84] Denser feeds might increase coke yield on coker feed volume by ≈10% (see tables 7.1-2, 7.1-6 in Meyers, 1986), not counting the effect of increasing coker feed volume. As compared with CO_2 emissions of ≈67.7 kg/GJ fuel gas and ≈56.0 kg/GJ natural gas, burning petroleum coke emits CO_2 at a rate of ≈108 kg/GJ. See Karras, 2010 at Table S1.
[85] SMF EIR 2012 Excerpts (attached). See esp. pages 2-1 (describing SMF–Rodeo integration), 2-11 (processes, and intermediates sent to Rodeo), 2-25 (project would increase deliveries of oils to Rodeo via pipeline), and 2-26 (project potential for 408,255 tons/yr increase in coke produced).
[86] See *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 SMF.

Project Impacts on the Environment

48. Project emissions would exceed a climate significance threshold, as the DEIR's emission estimates show, when its failure to account for emissions from burning project LPG is corrected. See paragraph 45. A check on its estimates, accounting for the 8,000 b/d of LPG (464,243 m^3/yr) sold and replaced by natural gas for refinery fuel, confirms that project GHG emissions would exceed the significance threshold established in the DEIR by more than 40 times. See Table 5. These observations make sense because oil refining emits more GHG than any other industry in California,[87] and the project would increase fossil fuel combustion associated with the refinery's activities substantially.[88] Among other potential measures to lessen or avoid this impact, the County could consider requiring that refinery use of electricity from the grid be purchased from renewable, rather than fossil-fueled, generation sources.

Table 5. GHG emissions from project LPG and natural gas to replace it in fuel gas

	DEIR estimate (CO_2e)[a]			CBE estimate (CO_2)[b]		
	LPG	natural gas		LPG	natural gas	
volume (m^3/yr)	464,243	310,000,000		464,243	313,000,000	
energy (GJ/yr)	11,230,541	11,230,541		11,900,000	11,900,000	
emissions (tonnes/yr)	759,244	592,761		782,000	666,000	
change in off-site LPG emissions			759,244			782,000
change from replacing LPG in fuel gas			-166,483			-116,000
net of other project emissions identified[a]			-159,495			-159,495
Total project emissions identified in DEIR			**433,266**			**506,505**
Threshold of significance from DEIR			10,000			10,000

LPG volume shown as liquid, from DEIR Table 3-2. (a) DEIR data from Table 4.8-3, except energy estimate from page 4.8-16 and natural gas volume estimate from Table 3-2. Other project emissions: boiler, mobile source and indirect emissions minus shutdown credit. (b) Based on natural gas energy equivalent to project LPG volume and heat contents (25.62, 0.038 GJ/m^3) and CO_2 emission factors (65.76, 55.98 kg/GJ) for LPG and natural gas, respectively, from Table S1 in Karras, 2010.

49. Stored under pressure, project gases could explode. Because predicting when this catastrophic and irreversible consequence might occur is ultimately speculative, and a safer design that might eliminate this hazard could be precluded after the project is built, the project as proposed would create an *inherent hazard.*[89] The project's failure to

[87] See CARB, 2013.
[88] Project LPG sales burned elsewhere and replaced with natural gas onsite would represent ≈44% of all fuel energy burned in the refinery in 2011, based on DEIR data (see pages 4.6-2, 4.8-16).
[89] See: CSB, 2013 at 40–48, 55.

demonstrate the use of inherently safer systems (ISS)—including cooled instead of pressurized storage, which would eliminate this catastrophic explosion hazard—through a process hazard analysis (PHA)[90] would conflict with the Industrial Safety Ordinance. Therefore, project gas storage under pressure would result in a hazard impact. The DEIR failed to identify the significance of this impact because its analysis ignored hazardous siting conditions and PHA and ISS requirements, and rejected analysis of an inherently safer measure that could avoid a catastrophic hazard based on cost, contrary to safety best practice and the Industrial Safety Ordinance. See paragraphs 39–44.

50. Pressurized gas storage explosion hazard resulting from the project can be mitigated but the DEIR did not complete its analysis of this mitigation opportunity. The County could consider developing an appropriate permit condition requiring cooled storage of propane and butane stored as a result of the project. Developing an appropriate permit condition would require reporting and evaluation of the PHA and documented ISS analyses that were not reported or addressed in the DEIR.

51. Expansion of the existing once-through cooling system would conflict with state plans and policies to phase out and replace this antiquated technology and foreclose an opportunity to replace the system in the near term via ongoing work to implement those plans and policies. Increased impingement, entrainment and thermal waste impacts that would result from the project would adversely impact aquatic biota and have the potential to injure or kill members of the remaining populations of threatened or endangered fish species that depend upon aquatic habitats in the vicinity of the refinery. Therefore, the project would adversely impact the biological resources of the San Francisco Bay-Delta ecosystem in conflict with state plans and policies.

52. The DEIR failed to identify the state plans, policies, and ongoing work the project would conflict with and foreclose by expanding the once-through cooling system. Due to these errors and its assumption of an erroneous project baseline it targeted only a fraction of the intake and discharge flow that would result from the project for its impact analysis. The DEIR reported no biological analysis of actual system effects that includes data representative of the expanded system. Its conclusions ultimately relied on a description of flow, heat, and discharge limitations that is demonstrably incorrect. As a result, it did

[90] No documented PHA or ISS is included in the DEIR, and County safety staff still sought these analyses, *including for cooled storage,* as of 11 July 2013. CHMP-Phillips071113; DEIR at 6-5.

not identify the significance of this impact. See paragraphs 27–38. The County could consider, among other measures to lessen or avoid this impact, requiring replacement of the antiquated once-through cooling system with closed loop cooling towers.

53. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, and this impact could be significant, but the DEIR did not analyze, or include information needed to analyze, this potential impact. The project outlined *in concept* might cut emissions substantially, but the DEIR's claim that refinery wide SO_2 emissions will be cut by 50% is wrong for several reasons. The project application for "emission reduction credits" to *increase* SO_2 emissions by 174.7 tons/yr that Phillips asserts will be used to achieve "no net increase" in project emissions would foreclose an emissions cut. See paragraph 26. Further, if the actual emissions cut from treating and replacing fuel gas is less than 174.7 tons/yr, emissions could increase. The extent of this potential increase cannot be quantified because data to support the emission credits—such as fuel gas hydrotreating specifications, and pre- and post-project fuel gas balances showing the composition and flows of gases among process units—is not included in the DEIR.

54. Importantly, this undisclosed change in the project that would foreclose the promised SO_2 emissions reduction conflicts with the DEIR's stated project objective to reduce emissions. 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. Developing an effective condition could be expected to require, among other things, analysis of the fuel gas composition and petroleum coke disposition data that is not disclosed in the DEIR (see paragraphs 24 and 46).

55. Flaring could be caused by fuel gas quality upsets resulting from the project because it lowers the heat content of gases burned throughout the refinery without upgrading equipment designed to burn gases with higher heat content. Fuel gas quality upsets, including those involving low heat-content gases, have caused significant flare episodes at the refinery repeatedly.[91] The company's shifting statements about whether existing burners should be or will be upgraded underscore the potential for increased frequency and magnitude of this type of flaring.[92] Flaring from fuel gas *quality* upsets can occur independently from that caused by fuel gas *quantity* upsets, and the DEIR did

[91] Flare Causal Analysis excerpts; see also CBE, 2007. *Flaring Prevention Measures.*
[92] See paragraph 25; Air Permit Correspondence; see also paragraph 14.

not analyze or mitigate this fuel gas quality issue. Moreover, flaring episodes impact air quality and health via acute exposures around each episode,[93] so that fuel gas quality flaring from the project could cause significant impacts even if the project reduces flaring from fuel gas quantity problems. To support a complete and reliable analysis of impacts on flaring, specifications for the changed fuel gas quality and for all of the combustion equipment that could be affected by this change must be reported and analyzed.

56. Flaring likely would be caused by the crude switch resulting from the project. Three independent reviews following the refining of higher sulfur crude at Gulf Coast and Bay Area refineries found evidence for increased flaring and flare emission intensity from hydrocracker and hydrotreater upsets.[94] This potential impact would not be mitigated by project treatment of fuel gas because the emergency shutdowns of these high-pressure processes that initiate the flaring typically requires dumping their contents to flares, bypassing fuel gas treatment. Indeed, flaring is allowed in emergencies, despite known local air impacts,[95] as a last-resort emergency response safeguard *after* potentially catastrophic conditions begin to manifest. This flaring indicates a process hazard.

57. The DEIR did not describe or evaluate upset flaring or any other impact of the denser, more contaminated crude slate that likely would result from the project. The denser hydrocarbons disproportionately present in denser crude oils have many more carbon atoms, and much lower hydrogen : carbon ratios, than the gasoline, diesel, or jet fuel made from these oils. These dense hydrocarbons also have greater concentrations of contaminants—such as sulfur, nitrogen, nickel, vanadium, selenium, and naphthenic acids, among others—that are toxic, corrosive, poison process catalysts, or decompose in refining processes to form toxic and corrosive compounds such as hydrogen sulfide (H_2S). Density and contaminant content broadly correlate among well mixed blends of whole crude oils from many different locations and geologies.[96] But complicating assessment and further increasing the hazard, this correlation breaks down in the case of

[93] See CBE, 2005. *Flaring Hot Spots;* BAAQMD, 2006 at 6–8.
[94] Subra, 2008; Karras, 2008; Dolbear, 2008 (Dolbear AG Summary). The concise notes from Dolbear's review inform the need to check for unanticipated hazards from crude switching: "This work forced me to think through this system again, and I conclude that, at least in the refineries in question, increasing contaminant levels do result in stressing the system to lead to upsets".
[95] Compare BAAQMD, 2006 at 6–8 (documenting flaring impact on nearby community) with BAAQMD Flare Control Rule 12-12 §101 (nothing in rule should be construed to compromise safety) and §301 (standard allows flaring in emergency to avoid potentially worse consequences).
[96] See Speight, 1991; Karras, 2010.

some individual crude oils that the project could lock the refinery into processing. In particular, partially pre-processed oils[97] and bitumen[98] derived from tar sands can be highly contaminated relative to their density.

58. Lower quality crude is an inherently more hazardous feedstock. Making engine fuels from its denser, hydrogen-poor hydrocarbons requires processing proportionately more of each barrel using severe carbon rejection (e.g., coking) and hydrogen addition (e.g., hydrocracking) and making that hydrogen, increasing refinery energy use and fuel burning for that energy.[99] Its greater contaminant content results in greater amounts of various toxic chemicals passing through the refinery into the environment, potentially increasing fugitive emissions of benzene and other toxics,[98] and in some cases boosting per-barrel releases of toxic trace elements by up to an order of magnitude.[100] The larger volume of toxic, flammable, and corrosive materials undergoing severe processing at high temperature and pressure further increases the frequency of process malfunctions and upsets over time, and the magnitude of these incidents when they occur.

59. Switching to higher sulfur crude was a causal factor in the disastrous Richmond refinery fire on 6 August 2012. See Chart 4. Sulfur corrosion of the pipe section that ruptured catastrophically in the incident (gray shading), sulfur in the gas oil running through this pipe (black line), and sulfur in the refinery crude feed supplying that gas oil (red line) are shown in this chart. The percent change from baselines is shown.[101] As sulfur increased in the crude, it increased in the gas oil distilled from that crude and running through the pipe, and sulfidic corrosion began to thin the wall of this pipe more than four times faster than before that dramatic sulfur increase. See Chart 4. This example of an ultimately disastrous feedstock substitution hazard applies to the SFR and the even more inherently hazardous crude feed that likely would result from the project.

60. Sulfur attacks metal equipment in contact with oil streams at temperatures above ≈230 ºC, causing thinning that leads to catastrophic ruptures, so that "sulfidic" corrosion "continues to be a significant cause of … incidents associated with large property losses

[97] See Karras, 2010.
[98] See Fox, 2013.
[99] See Karras, 2010; UCS, 2011; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson 2012.
[100] See CBE, 1994; and Wilhelm et al., 2007.
[101] For example, sulfur increased by more than 50% in crude based on crude sulfur content > 1.5 wt. % (Aug 2011–Jul 2012 avg.) versus a baseline < 1 wt. % (1996 avg.). See Karras, 2013.

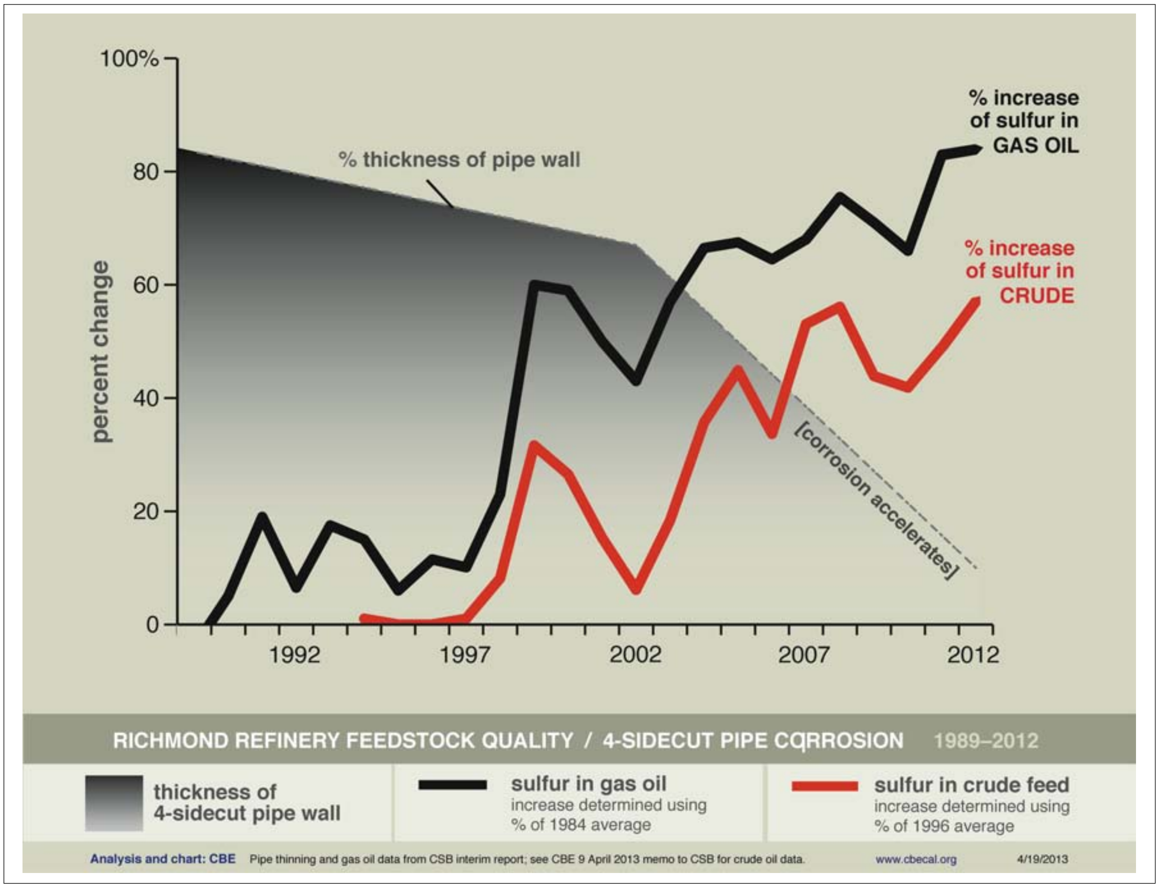


Chart 5. Richmond refinery feedstock quality / 4-Sidecut pipe corrosion, 1989–2012.
From testimony presented in the 19 April 2-13 U.S. Chemical Safety Board public hearing at Richmond, CA.

and injuries."[102] Sulfidic corrosion can occur anywhere in refineries where sulfur-bearing oils are processed this hot.[102] "Process variables that affect [sulfidic] corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system."[103] Higher sulfur crude feeds can accelerate sulfidic corrosion dramatically.[104] See Chart 4. All steels are attacked, but carbon steel, and carbon steel that has low silicon content, are particularly vulnerable.[104] U.S. refineries built before 1985 are especially vulnerable because they likely include low-silicon carbon steel equipment components.[104] Newer equipment can be similarly vulnerable because, perhaps in the rush to build and restart production, it may be made from inappropriately

[102] API, 2009 at vii. See also pages 3–8, and 16; and CSB, 2013 at 29–30.
[103] CSB, 2013 at 16.
[104] See CSB, 2013 at 16–45; see esp. 33–36. see also API, 2009.

corrosion-vulnerable alloys mistakenly installed, and then operated because of this error.[105] Sulfidic corrosion is difficult to monitor: it may accelerate in a few small, vulnerable, yet critical components of refinery piping systems many miles long, requiring monitoring of 100% of the components, but that is costly and may not be performed.[106] Actions taken to cut energy costs have in some cases inadvertently exacerbated sulfidic corrosion.[107] Further, in addition to introducing another hazard, corrosion resulting from naphthenic acids (TAN) in the crude can exacerbate sulfidic corrosion.[108] Ignoring or failing to recognize the nature of this hazard is part of the problem—impacts of a new and different feedstock are at best difficult to predict, and past operating history is *not* a guide to the future hazard when a refinery switches to a new and high-sulfur crude.[109] The proposed project at SFR presents these aspects of this hazard.

61. Sulfur is likely to reach ≈3–4 wt. % in the new crude slate that would result from the project. See paragraphs 12–22. This could cause more aggressive sulfidic corrosion than the increase to ≈1.55 % sulfur that caused the catastrophic pipe failure in 2012 at Richmond. The new crude slate is also likely to include more high TAN tar sands oils that could further exacerbate sulfidic corrosion and create a new corrosion hazard.[110] The Rodeo facility was built before 1985: carbon steel equipment that is especially vulnerable to sulfidic corrosion is likely present in the plant. The project as proposed documents no positive materials identification program that is addressing this vulnerability. Nor does it document any management of change, process hazard, or inherently safer systems analysis of this hazard, in conflict with the ISO and industry standards.[111] The project, as proposed, would create a catastrophic hazard resulting from switching to a new crude and rely, in essence, on past operating history to address this hazard. That is unsafe.

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[105] Incorrect alloys for corrosion resistance may have been installed mistakenly in up to 3% of piping components and 10% of items such as drain plugs at some refineries (API, 2009 at 16).
[106] See CSB, 2013 at 16–45; see esp. 33–36. see also API, 2009.
[107] See API, 2009 at 8; CSB, 2013 at 33.
[108] Total acid number (TAN), measured in mg KOH/g oil, reflects organic acids in crude oils that refiners call "naphthenic" acids. "[I]t is important to note that naphthenic acids can dissolve the iron sulfide scale [that might otherwise slow sulfidic corrosion] or at the very least render it less protective. ... [and it] is often difficult to isolate the individual effects of naphthenic acids and sulfur compounds [but] naphthenic acid never lowers sulfidation corrosion." API, 2009 at 4.
[109] CSB, 2013 at 35; API, 2009 at 5, 7, 8 and 16.
[110] TAN ranges from ≈0.9– 1.7 mg KOH/g in tar sands oils that are likely to be refined as a result of the project (see Table 3): 0.5 mg KOH/g is considered high for this acid (see Sheridan, 2006).
[111] County safety staff noted these PHA and ISS requirements (CHMP–Phillips071113); failure to analyze corrosion impacts of crude changes also violates industry standards (CSB, 2013 at 36).

62. Chart 5 shows data describing the scale of emissions from burning more fuel for the extra energy to refine denser, more contaminated crude slates. GHG emissions are plotted against crude slate density. Each white circle represents an annual average observed in one of the four largest U.S. Petroleum Administration Defense districts (PADDs) from 1999–2008; each orange diamond an observed California-wide annual average from 2004–2009; and the black square represents the Shell Martinez refinery annual average observed in 2008. The diagonal rise among the 47 observations from left to right in the chart indicates denser crude slates increase refinery emissions. Observed average emissions nearly double, from ≈260–500 kg/m^3 crude refined, as crude density increases from 860–932 kg/m^3. The SFR crude slate density increment that could result from the project (+37 kg/m^3; paragraphs 12–22) is shown by the width of the yellow band in the chart; the right-hand edge of this band shows the density of the WCS/ANS blend that the refinery could run as a result of the project (952 kg/m^3; see Table 4). This crude slate approaches the density of "heavy oil" as defined by the USGS (957 kg/m^3),[112] and is considerably denser than the Martinez refinery observation (932 kg/m^3), which appears near the middle of the yellow band shown in the chart.

63. Analysis that separated crude quality effects on emissions from those of other factors demonstrated that crude density (shown in Chart 5) and sulfur content (not shown) can explain 85–96% of observed variability in emissions among refining regions and years, allowing the prediction of average emissions from crude slates.[113] Predictions based on the U.S. observations suggest that an industry-wide switch to refining "heavy oil" (shown) and bitumen (not shown) could double or triple current U.S. refining emissions.[114] More recent work using different methods estimates emission increments that are generally consistent with these predictions.[115] Also, the U.S. data and methods used in these predictions were found to predict the observed emissions from the Martinez refinery within ≈7% and the long-term 2004–2009 average California industry emissions within ≈1%.[116] Based on these same data and methods, the project increase in SFR crude

[112] Heavy oil average density (957 kg/m^3) and sulfur content (2.9 wt. %) from Meyers et al., 2007.
[113] Karras, 2010; UCS, 2011.
[114] Karras, 2010.
[115] See Abella and Bergerson, 2012 (bitumen and dilbit vs. light conventional oils in Figure 1).
[116] UCS, 2011. See pages 9, 12 and 13, and Table 1-1. Four other refinery-specific predictions were tested as well (not shown in chart). When uncertainties caused by the lack of facility products reporting were considered, observed emissions from 4 of the 5 plants were predicted successfully, and emissions were underpredicted in 1 test. These predictions were tested by withholding the California energy and emission observations from the predictive model.

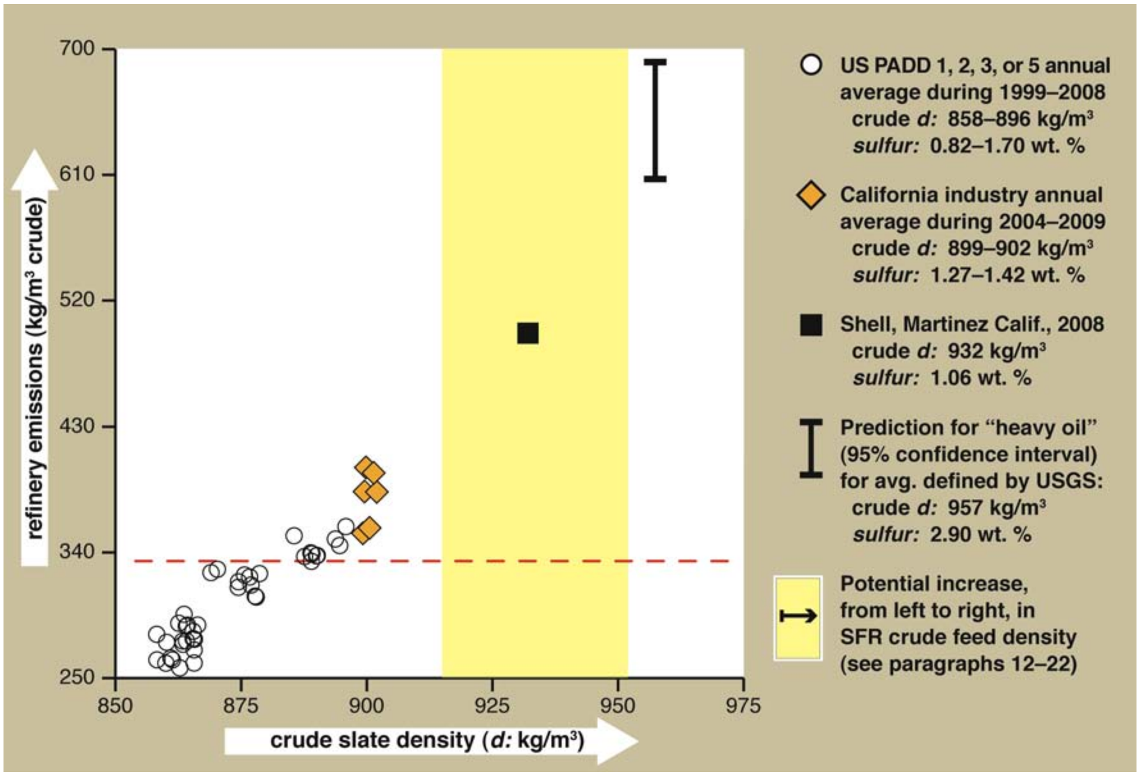

Chart 5. Refinery GHG emission intensity vs. crude feed density. CO_2 emissions increase from ≈260–500 kg per m^3 crude feed as crude density increases from 860–932 kg/m^3. Density (shown) and sulfur (not shown) explain 85–96% of these changes in emissions among refining regions and years. Emissions of ≈610–690 kg/m^3 are predicted from refining the average "heavy oil" (*d,* 957 kg/m^3; *S,* 2.9%). Plant-specific emissions also vary with other properties of oil feeds, products, process configurations and fuels burned, however, the WCS/ANS crude feed shown in Table 4 (*d,* 952 kg/m^3; *S,* 3.4%) is nearly as dense as this heavy oil and denser than a dozen feeds with observed emissions greater than current SFR emissions reported (334 kg/m^3 2009–2011; shown on the vertical scale by the dashed red line). The potential increase in SFR crude feed density (≈915–952 kg/m^3) is shown on the horizontal scale by the width of the yellow band. Each 90 kg/m^3 increment shown on the vertical scale represents emitting 627,000 tonnes/yr at SFR's 120,000 b/d capacity. Data from Karras (2010) and UCS (2011) except SFR emissions (CARB, 2013 for Rodeo and Santa Maria refining and Rodeo Air Liquide H_2 at *Oil & Gas Journal,* 2012 crude capacity).

slate density from 915–952 kg/m^3 and sulfur from 1.5–3.4% could increase the average refinery's energy intensity by ≈2.75 GJ/m^3 crude refined.[117] Assuming the refinery fuels reported in the DEIR,[118] and this average energy increment, SFR emissions of CO_2 would increase by ≈135 kg/m^3, or ≈940,000 tonnes/year. (Each 90 kg/m^3 increment on the vertical scale in Chart 5 represents emission of 627,000 tonnes/yr at SFR's 120,000 b/d capacity.) This ≈940,000 tonnes/yr value indicates the scale of potential impact rather than its precise quantification, as discussed directly below.

[117] Based on baseline and potential central predictions; confidence of increase > 95%.
[118] Based on fuel mix emission intensity ≈64.23 kg/GJ before and ≈59.45 kg/GJ after project fuel switch, from data in DEIR chapters 4.6 and 4.5; emission factors in UCS (2011) Table 2-1.

64. Plant-specific GHG emissions can vary from industry-average increments with differences in fuels burned, product slates, process configuration, and other properties of oils refined.[119] The DEIR's fuel mix assumption is an example of this variability. The relatively less-dirty current refinery fuel mix it reports[120] appears consistent with SFR's current emission estimate that appears somewhat low in Chart 5 (see dashed red line).[121] However, the DEIR's assumption that *only* natural gas will replace the LPG taken from refinery fuel ignores the potential for burning more petroleum coke in the refinery. See paragraph 46. The 940,000 tonnes/yr figure above could underestimate refinery emissions if any of this LPG is replaced by burning the project's extra coke.

65. Anomalous product slates must be considered, in general, because a refinery that makes much less (or much more) of its crude feed into light liquid fuels,[122] requires less (or more) energy for the severe carbon rejection and hydrogen addition processing needed to make these fuels from crude. This refinery, however, reports light liquid fuels production totaling more than 80% of its feedstock volume,[123] and project LPG would boost its light liquids product ratio still higher. The SFR products slate should be quantified and analyzed based on more data than the DEIR reported, but it is unlikely to decrease refinery GHG emissions relative to the industry average products slate.

66. SFR's process configuration could run the denser and more contaminated crude slate that likely would result from the project (see Table 4), but whether it would use more, or less, energy than the average refinery to do so is a more nuanced question. SFR has no catalytic cracker. Although it has very substantial carbon rejection (coking) capacity, this nevertheless makes it more reliant on severe hydrogen addition (hydro-

[119] Karras, 2010; Bredeson et al., 2010; UCS, 2011; Abella and Bergerson, 2012.
[120] See DEIR at 4.6-1, 4.6-2.
[121] This current SFR fuel mix emission estimate (≈64.23 kg/GJ; see note 118) is significantly less than the U.S. industry average (≈73.77 kg/GJ; see Karras, 2010 Table S1), but the SFR emissions reported by the company might be underestimated as well. SFR's emission reports received at least one "adverse" verification finding (CARB, 2013) and its Rodeo facility estimate appears slightly lower than that suggested by DEIR fuels data and UCS (2011) emission factors. These reported emissions (2009–2011 avg. including the Air Liquide Rodeo H_2 plant and Santa Maria facility based on CARB, 2013; kg/m^3 crude based on capacity from *Oil & Gas Journal*, 2012) are shown in Chart 5 because this is the emissions report available. Remarkably, the DEIR did not report *any* GHG emission estimate for the SFR refinery or even the Rodeo facility as a whole—a stark example of its failure to analyze this impact.
[122] Light liquid fuels: gasoline; diesel, jet fuel and similar distillates; LPG.
[123] See Phillips, 2012b at Table 1; EIR SCH #2005092028 at Table 3-4; EIR SCH #2002122017 at Table 4.5-2.

cracking, and associated H_2 production), and less reliant on carbon rejection processing, than a refinery with equivalent coking capacity *and* catalytic cracking. Several studies report that refinery configuration can affect energy intensity, emission intensity, or both—but they do not report specific evidence that substituting hydrocracking for catalytic cracking in a coking-based refinery reduces GHG emissions.[124] Instead, they cite hydrogen addition as a key factor increasing refinery energy intensity.[124] Further, the SFR process intensity exceeds reported averages in major U.S. PADDs by 22–78%.[125] Analysis across the U.S. PADDs did find a shift to a slightly less-dirty refinery fuel mix as refiners shifted from catalytic cracking to hydrocracking,[126] but this effect is accounted for already by plant-specific fuels data (see paragraphs 63–64). More detailed data on the SFR process configuration should be gathered and analyzed to better quantify potential emissions.[127] However, beyond the fuel mix (already addressed), there is little evidence that the SFR configuration will uniquely limit emission impacts from a denser and dirtier crude slate, and no evidence that denser crude can be converted to lighter products without energy—and resultant fuel combustion emission—costs.

67. Other properties of crude oils that affect processing may not be predicted reliably by density and sulfur in a poorly mixed crude slate. Many such properties are analyzed and reported (see Crude Assays). This data could have been included in the DEIR. For example, Abella and Bergerson's public domain estimation method calls for distillation, hydrogen content, and carbon residue data along with crude density and sulfur.[127] The project's coking dependence indirectly provides the key part of this distillation data (see paragraphs 14–20). However, hydrogen is a critical energy and emission driver.[124] Tar sands-derived oils tend to be H_2-poor, and refining them has, in some cases, increased energy use and emissions beyond those predicted by density and sulfur.[128] The project's likely use of these oils may emit more than the industry-average prediction suggests.

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[124] See Bredeson et al., 2010; Abella and Bergerson, 2012; Karras, 2010; UCS, 2011.
[125] Process intensity (*PI*): the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. SFR *PI* (1.60) based on data from *Oil & Gas Journal* (2012); U.S. *PI* (0.9–1.31) for PADDs 1, 2, 3, and 5 in 1999-2008 from Karras, 2010.
[126] Karras, 2010.
[127] The County could quantify potential emissions from the crude switch using non-confidential information and readily available analysis tools. Karras (2010) and Abella and Bergerson (2012) each present methods that are designed to be used with publicly verifiable data. Each method appears to have strengths and weaknesses relative to the other, and ideally, both should be used.
[128] See Abella and Bergerson, 2012; Fox, 2013; Karras, 2010.

68. Evidence discussed in paragraphs 62–67 shows that the crude switch likely to result from the project would increase GHG emissions substantially, and could increase them on the order of ≈1,000,000 tonnes/yr, but the actual increment might be half, or twice, that amount, and the DEIR failed to report data that could narrow this uncertainty. If even half (≈500,000 tonnes/yr) or only one-quarter (≈250,000 tonnes/yr) of this emission potential is realized, the emission increment would exceed the 10,000 tonnes/yr threshold of significance for GHG emissions asserted by the DEIR substantially.

69. Emissions of toxic and smog-forming combustion products could increase along with CO_2 as the project crude switch increases refinery energy intensity, requiring the SFR to burn more fuel per barrel of oil processed.[129] Emission of particulate matter air pollution (PM) is of specific concern. Fine particulate matter ($PM_{2.5}$) is associated with ≈14,000–24,000 premature deaths each year statewide, and $PM_{2.5}$ exceeds air quality standards in the project area, as the DEIR acknowledges.[130] Refinery emissions dominate PM exposures locally, and a statewide analysis of PM as a "GHG co-pollutant" found elevated, localized, and disparate health risks associated with refinery PM emissions.[131] The DEIR does not analyze PM emissions from the project crude switch or propose any additional abatement to address them. However, based on the emission factor Phillips reported for 100% natural gas boiler firing,[132] and the energy increment discussed above (≈2.75 GJ/m^3), the project crude switch could increase SFR emissions of $PM_{2.5}$ by an amount much greater than the significance threshold given in the DEIR.[133]

70. Cumulative impacts of the project with other projects that create long-term commitments to future emissions have the potential to result in failure to achieve the cut in emissions that will be necessary before 2050 to avert extreme climate disruption.[134] Indeed, substantial evidence indicates that stabilizing climate at a societally sustainable greenhouse impact level will require leaving approximately half of current fossil energy reserves underground.[134] Among other important implications of this evidence, it argues

[129] See Karras, 2010; Pastor et al., 2010.
[130] DEIR at 4.3-4, 4.3-5, 4.3-6.
[131] Pastor et al., 2010.
[132] See Air Permit Application at 10, 11 (0.0075 lb $PM_{2.5}$ per MMBtu, which is 3.42 grams/GJ).
[133] Potential emission increment is ≈9.4 g/m^3 crude refined (2.75 GJ/m^3 • 3.42 g/GJ as $PM_{2.5}$) or ≈65.4 tonnes/yr at SFR's 120,000 b/d (6.96 million m^3/yr) capacity. Even one fourth of this increment (≈16 tonnes/yr) exceeds the DEIR's $PM_{2.5}$ significance threshold (10 tons/yr). Other refinery fuel mix scenarios also result in $PM_{2.5}$ estimates exceeding this threshold.
[134] See Davis et al., 2010; Hoffert, 2010; Meinshausen et al., 2009; Allen et al., 2009.

for limiting impacts by choosing to use the least hazardous and least polluting portion of the remaining petroleum resource in the interim.

71. The County could consider a measure that results in using SFR hydrocracking to meet the project's LPG objective without relying on coking a low-quality crude slate. Hydrocracking can be operated to "swing" between product slates, allowing diesel or gasoline or LPG to be its main output, and unlike coking, hydrocracking treats (cleans) its products.[135] Making project LPG from SFR's existing hydrocracking while retaining the project's coker fuel gas hydrotreating is technically feasible and could meet all project objectives stated in the DEIR while avoiding impacts of its potential crude switch. However, increasing LPG output from SFR hydrocracking will limit its gasoline or diesel output,[135] while coker-based LPG production will not—and the proposed project would thereby further boost profits from total light liquids production. In fact, this is one of the reasons the project as proposed would lock the refinery into a denser, more contaminated crude slate. To support this feasible measure, the County could find that boosting profits in a way that makes the project unable to achieve its stated objectives to reduce emissions or to reduce the likelihood of flaring events is not a stated objective of the project.

72. The County also could consider other measures that may lessen impacts from the project's crude switch. However, many different measures may need to be developed to address the myriad potential impacts from refining denser, more contaminated crude. In addition, the relative efficacy of such measures to lessen these impacts cannot, in many cases, be known until the data and analysis that the DEIR could and should have provided to better estimate the scale or severity of these impacts is available for review.

73. On 13 June 2013 the Refinery Action Collaborative, a labor-community collaborative focused on addressing safety and health concerns shared by refinery workers and residents in the Bay Area, submitted to BAAQMD a "recommendation to ensure prevention of feedstock-related emissions increase" that reads in relevant part:

> To prevent new harm from feedstock-related emission increases, each refinery would be required to monitor and report its oil feedstock, and any proposed equipment change related to enabling a change in feedstock quantity or quality. Any proposed change in equipment related to enabling the refining of more oil, lower quality oil, or both, or any actual worsening of oil quality or increase in total oil throughput or both, would trigger a requirement to demonstrate that:

[135] See Robinson and Dolbear, 2007.

- the change in oil quantity, quality, or both (of the blend, of "slate" of oils refined) will not increase incident emission risk;[††]
- the change in oil quantity, quality, or both will not increase routine emissions of any pollutant; *and*
- the change in oil quantity, quality, or both will not use up any emission reduction measure that is needed to reduce the refinery's ongoing emission of any pollutant that currently causes or contributes to air quality or environmental health harm.

Refiners would bear the burden of making each of these demonstrations. The Air District would bear the burden of ensuring transparent reporting and third-party verification through an independent community/worker oversight board that selects and oversees experts. Refiners would bear the burden of funding this independent verification (the independent oversight board and the experts it selects).

Non reporting consequences: Non reporting must not be allowed to defeat prevention. Equipment changes enabling the refining of more oil, lower quality oil, or both that are not reported before installation (1) cannot be considered in a feasibility analysis as a reason for failure to return to baseline emissions, (2) trigger all required demonstrations retroactively, and (3) require refiner-financed Air District monitoring in place of self-monitoring.

[††] *We anticipate that this would be demonstrated through a Process Hazard Analysis or similar documented, verifiable analysis.*[136]

74. The foregoing recommendation[136] is the first specific blueprint for action to evaluate and prevent environmental health and safety impacts from refining lower quality oil that was developed jointly by refinery worker- and community-based organizations. This jointly-developed proposal could thus be considered a critically important step toward solving this problem as presented by the subject project, as well as many other refinery projects regionally and nationwide. Although the BAAQMD is considering this recommendation in the context of a proposed regional air quality rule that could address emissions from refining lower quality oil specifically, at present no such requirement is in place. Importantly, the recommendation describes in significant detail a comprehensive approach to data reporting, evaluation, catastrophic hazard prevention, and emission impact prevention problems presented by this project's potential crude switch. See paragraphs 12–23, 56–72. The County could consider this recommended approach as it completes its analysis, public review process, and decisions regarding the project.

[136] Refinery Action Collaborative, June 2013. Members include the Asian Pacific Environmental Network; BlueGreen Alliance; Communities for a Better Environment; Labor Occupational Health Program at U.C. Berkeley; the Natural Resources Defense Council; United Steelworkers International Union; United Steelworkers Local 5, and United Steelworkers Local 326.

Conclusions

75. Catastrophic failure hazard associated with pressurized storage of propane and butane that would be produced and stored without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR presented an incomplete analysis of this impact, did not identify it as significant, and rejected the consideration required by safety policy of a feasible measure to avoid this impact.

76. Catastrophic failure hazard associated with greater amounts of corrosive, toxic, and flammable materials under high heat and pressure that would be caused by the processing of lower quality oil without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure to avoid this impact appears feasible.

77. Acute exposures to air pollutants emitted by flaring to control upsets caused by the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

78. Acute exposures to air pollutants emitted by flaring associated with feeding fuel gases that have lower heat content to equipment designed to burn fuel gases that have higher heat content as a result of the project *may* be considered a significant potential impact—when data the DEIR did not include are reported and reviewed. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although such measures are feasible.

79. Exposures to localized air pollution from continuous emissions of fine particulate matter caused by increased fuel combustion associated with the processing of lower quality oil as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

80. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, if “emission reduction credits” resulting from the project are overestimated, and this *may* be considered a significant potential impact—when data the DEIR did not

include are reported and reviewed. The DEIR did not disclose these credits for a future emissions increase that could overwhelm the claimed emissions reduction from another part of the project. It did not analyze that emissions reduction claim against these credits to check on whether the credits are overestimated and could thus result in a net emissions increase. It did not consider any measure to lessen or avoid this potential impact, although a measure that could avoid this impact appears feasible.

81. Destruction of aquatic life and San Francisco Bay-Delta habitat caused by the expansion and continued operation of an outdated once-through cooling system as a result of the project should be considered a significant potential impact. The DEIR did not disclose state efforts that could replace the cooling system—thereby avoiding this impact—or that the project would conflict with and foreclose those efforts. The DEIR presented an incomplete, erroneous, and misleading discussion of this impact, did not identify it as significant, and did not consider any measure to lessen or avoid this impact.

82. Greenhouse gas emissions caused by burning propane and butane that would be produced and sent out of the refinery for this purpose as a result of the project should be considered a significant potential impact. The DEIR presented an erroneous analysis of these emissions, did not identify this impact, and did not consider any measure to lessen or avoid it, although such measures appear feasible.

83. Greenhouse gas emissions caused by increased refinery fuel combustion associated with the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

84. The June 2013 DEIR did 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.

85. 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 _____ day of September 2013 at Oakland, California

____
Greg Karras

Attachments List

Descriptor	*Attachment*
Abella and Bergerson, 2012	Abella and Bergerson, 2012. Model to investigate energy and greenhouse gas emission implications of refining petroleum: impacts of crude quality and refinery configuration. *Env. Sci. Technol.* DOI: 10.1021/es30186821.
AICE, 1989 (excerpts)	American Institute of Chemical Engineers, Center for Chemical Process Safety, 1989. Guidelines for process equipment reliability data, with data tables. (Excerpts: pp. 183, 205).
Air Permit App.	ERM, 2013. Rodeo Propane Recovery Project BAAQMD Authority to Construct and Significant Revision to Major Facility Review Permit Application, Rodeo Refinery. February 2013.
Air Permit App. Atts 4 and 7	ERM, 2013 (Permit Application). Attachment A-4. Fugitive component TAC emissions; and Attachment A-7. Daily U233 fuel gas data.
Air Permit Correspondence	Correspondence regarding incomplete permit application for the project including: 30 April 2013 letter to Brian Lusher, Bay Area Air Quality Management District, from Don Bristol, Phillips 66 San Francisco Refinery (4/30/13 Phillips letter); 6/28/13 Phillips letter; 3/1/13 Phillips letter; 1 March 2013 letter to Brent Eastep, Phillips 66 Rodeo Refinery, from Brian Lusher, Bay Area Air Quality Management District (3/1/13 BAAQMD letter); 3/21/13 BAAQMD letter; 7/18/13 BAAQMD letter.
Allen et al., 2009	Allen et al., 2009. Warming caused by cumulative carbon emissions towards the trillionth tonne. *Nature* 458: 1163–1166.
API, 2009	American Petroleum Institute, 2009. Guidelines for avoiding sulfidation (sulfidic) corrosion failures in oil refineries. API Recommended Practice 939–C, First Edition.
BAAQMD, 2006	Staff Report, Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries. Bay Area Air Quality Management District. 3 March 2006.
BAAQMD, 2009	Bay Area Air Quality Management District 18 September 2009 response to request for facility information by CBE (listing of Chevron Richmond Refinery dates of first operation by equipment source number; includes summary table by CBE).
BAAQMD, 2011	Major Facility Review Permit, Chevron Products Company, Facility #A0010. Bay Area Air Quality Management District. 11

	August 2011.
BAAQMD, 2013	Major Facility Review Permit, Phillips 66–San Francisco Refinery, Facility #A0016. Bay Area Air Quality Management District. 4 March 2013.
Brandt, 2012	Brandt, 2012. Variability and uncertainty in life cycle assessment models for greenhouse gas emissions from Canadian oil sands production. *Env. Sci. Technol.* 46: 1253–1261.
Bredeson et al., 2010	Bredeson et al., 2010. Factors driving refinery CO_2 intensity, with allocation into products. *Int. J. Life Cycle Assess.* 15: 817–826.
CARB, 2013	Mandatory GHG Reporting Data. Emissions reported for calendar years 2009, 2010, 2011. California Air Resources Board. (Dnldd 28 August 2013: https://ghgreport.arb.ca.gov/eats/carb).
CBE, 1994	CBE, 1994. Dirty crude: The first oil industry-wide analysis of selenium discharge trends impacting San Francisco Bay. CBE Report No. 94–1. March 1994.
CBE, 2006	CBE, 2006. Analysis of Potrero Unit 3 entrainment impact evidence. March 2006.
CCHMP–Phillips 071113	Letter to Jim Ferris, Phillips 66 San Francisco Refinery, from Michael Dossey, Contra Costa Health Services Hazardous Materials Program. 11 July 2013.
Chevron R2-2011-0049	NPDES Permit No. CA0005134. Chevron Richmond Refinery. Issued in 2011.
City of Richmond, 2008	Chevron Energy and Hydrogen Renewal Project Final Environmental Impact Report SCH #2005072117 Volume 3–Responses to Comments. January 2008.
Crude Assays	Compilation of publicly reported crude oil assay reports.
CSB, 2005	CSB, 2005. Investigation Report: Refinery Explosion and Fire (15 Killed, 180 Injured); BP Texas City, Texas, March 23, 2005. Report No. 2005–04-I-TX. U.S. Chemical Safety and Hazard Investigation Board. March 2007.
CSB, 2013	CSB, 2005. Interim Investigation Report: Chevron Richmond Refinery Fire; Chevron Richmond Refinery, Richmond, California, August 6, 2012. U.S. Chemical Safety and Hazard Investigation Board. April 2013.
CV and Publications	Curriculum vitae and publications list
Davis et al., 2010	Davis et al., 2009. Future CO_2 emissions and climate change from existing energy infrastructure. *Science* 329: 1330–1333.

DOE COA 2013	DOE, 2013. Crude Oil Analysis Database. U.S. Department of Energy. Data table in Excel. (www.netl.doe.gov/technologies/oil-gas/Software/database.html). Downloaded 8 August 2013.
DOE, 2002.	DOE, 2002. Strategic Petroleum Reserve Crude Oil Assay Manual, 2nd Edition, Revision 2. U.S. Department of Energy. Revised November 2002.
Dolbear AG Summary	Email from Rose Fua, California Deputy Attorney General summarizing and quoting from a review by Dr. Geoff Dolbear regarding the Chevron Richmond refinery (other Bay Area data were reviewed as well). Forwarded to CBE 16 July 2008.
EIA Imports Analysis	Tables of data for foreign oils processed by the San Francisco Refinery reported by the U.S. Energy Information Administration (www.eia.gov/petroleum/imports/comanylevel/archive)
EIA Ref. Cap. 2013	U.S. Energy Information Administration, 2013. Refinery Capacity Data by Individual Refinery as of January 1, 2013 (www.eia.gov/petroleum/data). Downloaded 26 August 2013.
EIA Refinery Yield	U.S. Energy Information Administration, 2013. U.S. Refinery Yield. (www.eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_m.htm)
ERCB st98–2009	ERCB, 2009. Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018. Report ST98–2009. Energy Resources Conservation Board, Alberta, Canada. June 2009.
ERM & BAAQMD, 2012	CEQA Initial Study: Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Application 22904. Bay Area Air Quality Management District (prepared by ERM). December 2012.
Flare Causal Analysis excerpts	Phillips 66, various dates. Determination and Reporting of Cause reports pursuant to BAAQMD Rule 12-12 §406 for flaring initiating on 3/16/12, 4/25/12, 5/23/12, 5/31/12, 8/27/12.
Flaring Hot Spots	Karras and Hernandez, 2005. Flaring hot spots: Assessment of episodic air pollution associated with oil refinery flaring using sulfur as a tracer. A CBE Report. July 2005.
Flaring Prevention Measures	Karras et al., 2007. Flaring Prevention Measures. A CBE Report. April 2007.
Fox, 2013	Fox, 2013. Comments on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN–00063. July 2013.
Goodman, 2013	Goodman and Rowan, 2013. Comments of the Goodman Group, Ltd., on Initial Study/Mitigated Negative Declaration, Valero

	Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063.
Hoffert, 2010	Hoffert, 2009. Farewell to fossil fuels? *Science* 329: 1292–1294.
Karras, 2008	Karras, 2008. Chevron Renewal Project, SCH #2005072117, City #1101974 Agenda Report, Consolidated EIR and Staff-recommended EIR and Conditional Use conditions and findings related to oil quality cap; expert report.
Karras, 2010	Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24): 9584–9589.
Karras, 2013	Testimony of Greg Karras, Senior Scientist, CBE, before the U.S. Chemical Safety and Hazard Investigation Board (CSB), 19 April 2013, Memorial Auditorium, Richmond, CA.
LOHP, 2013	Wilson, 2013. Refinery Safety in California: Labor, community and fire agency views. Summary report prepared for the Office of Governor Jerry Brown, Interagency Task Force on Refinery Safety, by the Labor Occupational Health Program at U.C. Berkeley. Revised 4 June 2013.
Meinshausen et al., 2009	Greenhouse-gas emission targets for limiting global warming to 2 ºC. *Nature* 458: 1158–1162.
Meyer et al., 2007	Meyer, 2007. Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084.
Meyers, 1986	Handbook of petroleum refining processes. Meyers, Robert A., ed. ISBN 0-07-041763-6. McGraw-Hill. 1986.
NPDES Permit R2-1985-029	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1985.
NPDES Permit R2-1989-002	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1989.
NPDES Permit R2-2000-015	NPDES Permit No. CA0005053. Tosco Corp. San Francisco Refinery at Rodeo. Issued in 2000.
NPDES Permit R2-2005-0030	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued 2005.
NPDES Permit R2-2011-0027	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued in 2011.
NPDES Permit R3-2007-0002	NPDES Permit No. CA0000051. ConocoPhillips Corp. Santa Maria Refinery. Issued in 2007.

Oil & Gas Journal, 2012	Koottungal, 2012. 2012 Worldwide Refining Survey. *Oil & Gas Journal.* 3 December 2012 (All figures are as of January 1, 2013).
Pastor et al., 2010	Pastor et al., 2020. *Minding the climate gap: What's at stake if California's climate law isn't done right and right away.* USC Program for Environmental and Regional Equity: Los Angeles, CA. http://college.usc.edu/pere/publications.
Phillips Cooling Tower	*Cooling Tower Replacement Feasibility Evaluation, Order R2-2011-0027; Provision VI.C.2.f., Phillips 66 San Francisco Refinery at Rodeo.* Submitted by Don Bristol, Superintendent, Environmental Services, Phillips 66 San Francisco Refinery, no 30 September 2013. (13-page report)
Phillips Intake Rpt.	*Waste Water Annual Report for 2012, Phillips 66, San Francisco Refinery.*
Phillips Thermal ext. 1	8 August 2012 letter from Don Bristol, Phillips 66 San Francisco Refinery, to Regional Water Quality Control Board, San Francisco Bay Region, regarding: *Phase 2 Thermal Plume Study Final Report, NPDES Order #R2-2011-0027, Provision VIC2d; Task 3 Request for Due Date Extension.*
Phillips Thermal ext. 2	4 September 2012 letter from Bruce Wolfe, Regional Water Quality Control Board, San Francisco Bay Region, to Don Bristol, Phillips 66 San Francisco Refinery, regarding: *Phase 2 Thermal Plume Study Final Report Compliance Date Extension.*
Phillips, 2012a	Phillips 66, 2012. *Propane Recovery Project Overview, August 13 2012, Phillips 66 San Francisco Refinery.* Submitted to BAAQMD. Provided by BAAQMD to CBE (slides presentation).
Phillips, 2012b	Phillips 66, 2012. *Rodeo Propane Recovery Project, Project Description.* August 2012. Submitted to BAAQMD. Provided by BAAQMD to CBE (32-page document).
Refinery Action Collaborative, June 2013	Letter to Jack Broadbent, Bay Area Air Quality Management District, from the Refinery Action Collaborative regarding: *Bay Area Air Quality Management District Proposed Regulation 12, Rule 15; March 2013 Preliminary Draft Petroleum Refining Emissions Tracking Rule.* 13 June 2013.
Regional Monitoring Program	Regional Monitoring Program (RMP) Results. San Francisco Estuary Institute. Data tables report generated by the RMP Web Query (www.sfei.org/mp/mp_data_access.html). Report generated 17 August 2013.
Robinson and Dolbear, 2007	Robinson and Dolbear, 2007. Commercial hydrotreating and hydrocracking. In *Hydroprocessing of heavy oils and residua;*

	Ancheyta, J., Speight, J.G., Eds.; CRC Press, Taylor & Francis Group: Boca Raton, FL. Vol. 117: 281-311.
Shell R2-2012-0052	NPDES Permit No. CA0005789. Shell Martinez Refinery. Issued in 2012.
Sheridan, 2006.	*California Crude Oil Production and Imports.* Staff Paper. CEC-600-2006-006. Margaret Sheridan, Fossil Fuels Office, California Energy Commission. April 2006.
SMF EIR 2012 Excerpts.	*Phillip 66 Santa Maria Refinery Throughput Increase Project Final Environmental Impact Report.* SCH #20081010111. Prepared for San Luis Obispo County Department of Building and Planning by Marine Research Specialists (MRS). October 2012. Excerpt includes cover page, table of contents, and project description (chapter 2.0).
Speight, 1991	Speight, 1991. *The chemistry and technology of petroleum*, 2nd ed.; Heinemann, H., Ed.; Marcel Dekker: New York, Chemical Industries, Vol. *44*.
State Lands, 1995.	*Final Environmental Impact Report for Consideration of a New Lease for the Operation of a Crude Oil and Petroleum Product Marine Terminal on State Tide and Submerged Lands at Unocal's San Francisco Refinery, Oleum, Contra Costa County.* SCH # 91053082. Prepared for State Lands Commission by Chambers Group, Inc. February 1995.
Subra, 2008	*Chevron Energy and Hydrogen Renewal Project.* Expert report prepared for the Asian Pacific Environmental Network by Wilma Subra, Subra Company, New Iberia, LA. May 2008.
SWRCB, 2010	*Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.* California State Water Resources Control Board. October 2010.
Tesoro R2-2010-0084	NPDES Permit No. CA0004961. Tesoro Golden Eagle Refinery. Issued in 2010.
UCS, 2011	UCS, 2011. *Oil Refinery CO_2 Performance Measurement.* Union of Concerned Scientists: Berkeley, CA. Technical analysis prepared for UCS by G. Karras, Communities for a Better Environment. September 2011.
Valero R2-2009-0079	NPDES Permit No. CA0005550. Valero Benicia Refinery. Issued in 2009.
Wilhelm et al., 2007	Wilhelm et al., 2007. Mercury in crude oil processed in the United States (2004). *Env. Sci. Technol.* 41(13): 4509–4514.

Comments

on

Environmental Impact Report

for the

Phillips 66 Propane Recovery Project

Rodeo, California

Prepared
for

Shute, Mihaly & Weinberger LLP on behalf of
Rodeo Citizens Association

November 15, 2013

Prepared by
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I. INTRODUCTION

The Phillips 66 San Francisco Refinery, located at Rodeo (Refinery), is proposing to recover an additional 4,200 barrels per day (BPD) of propane and 3,800 BPD of butane from the refinery fuel gas (RFG) (collectively known as "liquefied natural gas" or LNG) to export for sale (Project). I was asked by Shute, Mihaly & Weinberger to review the Draft Environmental Impact Report (DEIR)[1] for this Project, related files of the Bay Area Air Quality Management District (BAAQMD), and select responses to comments in the Final Environmental Impact Report (FEIR).[2] Based on this review, I was asked to evaluate the accuracy of the DEIR/FEIR Project Description and their analysis of the Project's air quality impacts.

My evaluation, presented below, indicates the Project would result in significant unmitigated air quality and public health impacts. The DEIR and FEIR significantly underestimate the amount of criteria pollutants and greenhouse gas emissions that would be emitted by the Project. Emissions of nitrogen oxides (NOx) and reactive organic gases (ROG) will exceed both daily and annual CEQA significance thresholds. These emissions plus certain hazardous air pollutants (HAPs) emissions that were not disclosed in the DEIR will cause significant unmitigated air quality and public health impacts.

The DEIR's Project description is incomplete. First, it fails to disclose the baseline crude slate, which determines the CEQA baseline emissions from all processing units within the Refinery. Second, it fails to disclose other directly related projects at the Phillips 66 Santa Maria Facility, which is linked by pipeline to the Rodeo Refinery. These directly related projects result in significant cumulative impacts that were not evaluated. Third, it fails to disclose related changes at the Rodeo Refinery itself, including a significant drop in refinery fuel gas heat content, which requires physical modifications to 19 process heaters. Finally, the Project description omits all of the key chemical composition data required to assess impacts and vet the DEIR's no significant impact conclusions.

My resume is included in Attachment 1 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 emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; 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

[1] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project, Draft Environmental Impact Report, June 2013 (DEIR).

[2] Contra Costa County Department of Conservation and Development, Phillips 66 Propane Recovery Project, Final Environmental Impact Report, November 2013 (FEIR).

Board Certified Environmental Engineer, certified in Air Pollution Control by the American Academy of Environmental Engineers; and a Qualified Environmental Professional, certified by the Institute of Professional Environmental Practice.

I have prepared comments, responses to comments and sections of EIRs for both proponents and opponents of projects on air quality, water supply, water quality, hazardous waste, public health, risk assessment, worker health and safety, odor, risk of upset, noise, land use and other areas for well over 100 CEQA documents. This work includes EIRs, Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries as well as various other permitting actions for tar sands refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas and 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 Facility.

My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee v. Board of Port Commissioners* (2001) 91 Cal.App.4th 1344 and *Communities for a Better Environment v. South Coast Air Quality Management Dist.* (2010) 48 Cal.4th 310.

II. THE PROJECT IS PIECEMEALED

The DEIR only evaluated a portion of the Project. The Project as described in the DEIR narrowly involves modifications to the Rodeo Refinery "to recover for sale propane and additional butane from refinery fuel gas and other process streams." DEIR, pp. 3-2, 3-5. However, the DEIR fails to disclose changes elsewhere that are required to produce all of the propane and butane that would be recovered.

The components of the Project evaluated in the DEIR include an LPG Recovery Unit, Fuel Gas Hydrotreating, Propane Storage, Railcar Loading Modification, and certain ancillary facilities. DEIR, Table 3-1 & Sec. 3.4. I reviewed the BAAQMD file for this Project and other currently pending and related projects. Based on this review, in my opinion, sufficient propane and butane could not be recovered from the current crude slate to support the Project's propane/butane production goals. Changes in the amount and type of feedstock would be required to achieve the propane and butane recovery goals.

The Refinery currently recovers up to 9,000 BPD of butane in the summer for sale.[3] DEIR, p. 3-17. The Project would increase butane recovery by 3,800 BPD and also recover 4,200 BPD of propane. The total butane and propane recovery after the Project has been implemented would be limited by permit conditions to a maximum daily of 14,500 BPD and 5,292,550 barrels per 12 consecutive months. 6/28/13 Response

[3] Butane sold as LPG has the disadvantage of a fairly high boiling point and thus is not desirable as a fuel during the winter when stored outdoors in areas that have temperatures below freezing.

Letter,[4] p. 5, Response to Comment #5. It is unclear whether this is 14,500 BPD in addition to the existing 9,000 BPD or a total of 14,500 BPD, including current baseline butane recovery.[5] The DEIR, for example, clearly states that the Project would recover 3,800 BPD of "additional butane." DEIR, p. 3-23. This should have been clarified in the FEIR, but was not. Regardless, this is a large amount butane and propane for a refinery that processes very heavy crudes configured as shown in DEIR Figure 3-4 . Thus, other modifications, not disclosed in the DEIR, are required to fully implement this Project.

The average feedstock to the Refinery over the period 2007 to 2011 was 116,800 BPD and ranged from 110,000 BPD to 128,000 BPD, or nearly up to its reported capacity of 130,000 BPD. DEIR Project Description,[6] Table 1. Thus, the proposed butane plus propane recovery Project would convert about 12% of the baseline feedstock to butane and propane, assuming a total of 14,500 BPD. If one assumes the Project would recover 14,500 BPD additional, plus the existing 9,000 BPD, 20% of the feedstock would be converted. Further, about 16% of the product output of the Refinery, estimated as 89,400 BPD over the period 2007 to 2011 (DEIR Project Description, Table 4), would be propane and butane.

These high percentages are not consistent with my experience, particularly for the mainly heavy crudes and semi-refined products from heavy crudes processed at this Refinery, which have much lower amounts of these low-boiling products.[7] The DEIR and other documents I consulted contain no information that would allow me to directly estimate the amount of propane and butane that could be recovered from baseline feedstock such as:

- composition of the Refinery fuel gas and other gas stream from which propane and butane would be recovered, e.g., gas chromatographic analyses;
- distillation curves and composition data for the crude, semi-refined feedstock inputs from elsewhere, and other internal streams that would routed to the subject Project;
- relative amount of crude and semi-refined feedstock;
- material balance or outputs of refinery models.

These high values for propane/butane recovery suggest that the feedstock input will be modified in conjunction with the Project. Yet the DEIR lacks the data or calculations that support the foundational assumption that 100% of the propane/butane can be recovered from the baseline refinery fuel gas.

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[4] Letter from Don Bristol, Phillips, to Brian Lusher, BAAQMD, Re: Response to Incomplete Letter 5/21/13 Application #25199, June 28, 2013 (6/28/13 Response Letter).

[5] The 4/30/13 Response Letter, p. 4, Response to Comment #6 states "The throughput [14,500 BPD] includes butane that is currently being recovered as well as the butane and propane that will be recovered as part of this project."

[6] Phillips 66, Rodeo Propane Recovery Project Description, August 2012.

[7] Oil Transportation Information at http://www.oil-transport.info/crudedata/crudeoildata/crudeoildata.html

The FEIR asserts that "the actual amount of propane and butane currently available for recovery (determined using measured flow data and lab analysis of propane and butane content) is approximately 4,200 bpd of propane and 9,300 bpd of butane." FEIR, p. 3.2-130. However, none of this data is in the record. We do not know, for example, if the amount "currently available" is the amount being processed in the CEQA baseline, or the amount that will be available for processing in the future, after the Project is implemented, based on other changes at other related Phillips 66 facilities, such as at Phillips 66's Santa Maria Facility or Ferndale Refinery.

A crude throughput expansion project, for example, was recently approved at the Phillips 66 Santa Maria Facility, which is linked by pipeline to the Rodeo Refinery. This project is further discussed below. In summary, the DEIR for the Santa Maria Facility (referred to as SMF DEIR/FEIR in these Comments) clearly states that partially refined products from this increase in crude will be sent to the Rodeo Refinery for further processing. As explained below, these partially refined products are feedstocks to the Propane/Butane Recovery Project. The Santa Maria crude throughput increase project is not operational yet. Thus, there is solid evidence that there will be increases in the input to the Propane/Butane Project from related projects elsewhere in the Phillips 66 system that are not part of the instant CEQA baseline. Thus, the amount "currently available" likely includes future increases in production that have not been disclosed in the Propane/Butane Project DEIR or FEIR. Thus, cumulative impacts of these two projects should have been evaluated and the increase in emissions from processing the increase in semi-refined products from Santa Maria at Rodeo should have been included in the emission calculations.

As the cited flow data and lab analysis are asserted to establish the Project baseline and is part of the Project description (i.e., it determined the design basis of the Project), it must be provided for public review. This is particularly critical here as the claimed recovery of propane and butane from the baseline feedstock is very high for the type and amount of crude that the FEIR asserts is currently refined and the existing Refinery configuration. As noted above, other projects currently proposed by Phillips 66 could increase the recoverable propane and butane, making up the deficit.

The San Francisco Refinery (SFR) consists of two facilities linked by a 200-mile pipeline. The Santa Maria Facility (SMF) is located in Arroyo Grande, in San Luis Obispo County, while the Rodeo Refinery (referred to as "the Refinery" in these Comments) is located in Rodeo in the San Francisco Bay Area. The SMF mainly processes heavy, high sulfur crude oil and sends semi-refined liquid products, e.g., gas oil, to the Rodeo Refinery. SMF DEIR,[8] pp. ES-2, 1-1 and Table 2-3. The Refinery DEIR does not disclose the existence of this related facility but it is acknowledged in the FEIR. FEIR, Master Response 2.2.

[8] 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.

The subject DEIR addresses changes at just the Rodeo Refinery to increase butane and propane production, once the proper amount of the right feedstocks arrive. As discussed above, the DEIR is silent on the composition and relative amounts of feedstock (heavy crude, semi-refined products received from SMF) and the FEIR adds no additional information. Additional feedstock containing recoverable propane and butane is required.

Additional feedstock could be produced by proposed modifications at the Santa Maria Facility to increase its production of semi-refined feedstock (gas oil and naphtha), to send to the Rodeo Refinery. Phillips 66 proposed to increase the production of semi-refined products at the Santa Maria Refinery specifically to send to the Rodeo Refinery. SMF DEIR, p. ES-4. This throughput increase would necessarily be included in the streams from which propane and butane would be recovered, as explained below. Another related Phillips 66 project (rail spur extension required to import increased amounts of crude to support the throughput expansion) at the Santa Maria Facility is currently undergoing CEQA review. The SMF Rail Spur DEIR is expected to be released soon. My commentary here is based on the Rail Spur Land Use Application. SMF Rail Spur Land Use Ap.[9] These two projects provide the missing links in the butane/propane supply chain at the Rodeo Refinery.

The Santa Maria throughput increase project would increase ". . .the volume of products leaving the SMF for the Rodeo Refinery via pipeline." SMF DEIR, pp. ES-4, 2-25. The products are not specifically identified in this statement, but are noted elsewhere as gas oil and naphtha. SMF FEIR, pp. 2-11, 2-17. These semi-refined products would contain a significant amount of butane and propane[10] and would be further processed at the Rodeo Refinery to generate additional butane and propane, as explained further below. DEIR, Figs. 3-4 and 3-6.

The SMF DEIR for the throughput increase project included a clarifying statement as to the products that would be sent to Rodeo, which was deleted in the FEIR: "an increased volume of products leaving the SMF for the Rodeo Refinery via pipeline (including semi-refined crude oil or a combination of semi-refined crude oil and previously refined gas/oil petroleum)." SMF DEIR,[11] p. 2-25. This omission is material as it indicates that more than semi-refined products from the SMR would be sent to the Rodeo Refinery. This omission suggests crudes could also be sent to the Rodeo Refinery. This clue, coupled with the rail spur extension project suggests that tar sands crudes, some of which are semi-refined, could additionally be sent to the Rodeo Refinery via rail import at Santa Maria. This issue is discussed below.

The SMF FEIR indicates the throughput of the Santa Maria Facility would increase from the permit level of 44,500 BPD (SMF FEIR, p. ES-4) by 10% to a maximum of 48,950 BPD or by 4,450 BPD. SMF FEIR, p. 1-1. However, the permit

[9] Phillips 66 Company, Land Use Application, Santa Maria Refinery Rail Project, June 2013.

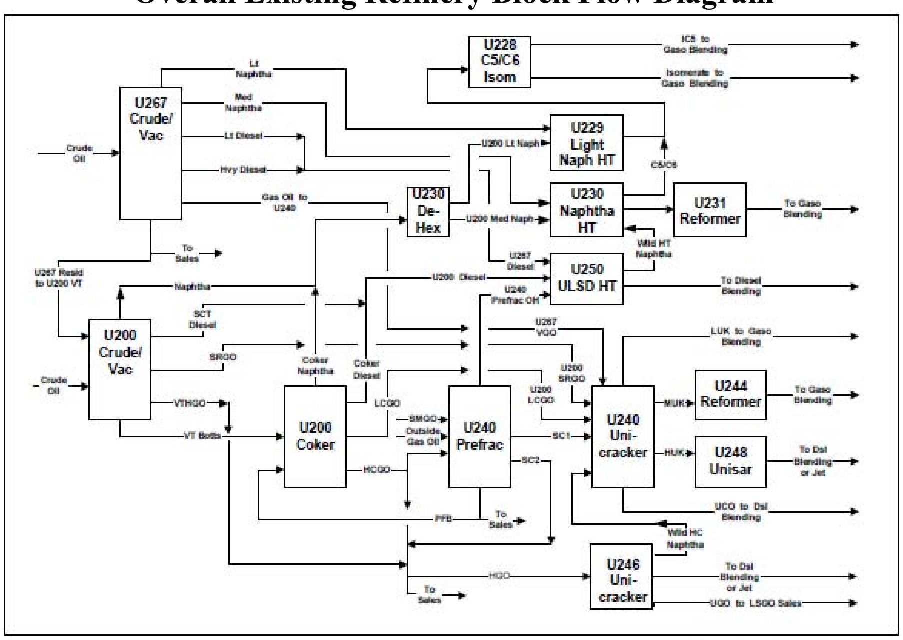
[10] See, e.g., MSDS for naphtha, available at: http://www.collectioncare.org/MSDS/naphthamsds.pdf .

[11] Marine Research Specialists, <u>ConocoPhillips Santa Maria Refinery Throughput Increase Project</u>, Public Draft Environmental Impact Report, August 2011.

level is not the baseline for CEQA. The actual throughput for the last three years of available data is 40,275 BPD. Thus, the SMF throughput increase project would increase the throughput of the SMF by 8,675 BPD. This increase would be converted into semi-refined products in the SMF's distillation units and coker to yield gas oil and naptha, which would be sent to the Rodeo Refinery, where propane and butane would be separated, contributing to the propane/butane slated for recovery by the Rodeo Project.

This link is clearly shown in the Rodeo Refinery block flow diagrams in the subject Rodeo Refinery DEIR. The block flow diagram for the existing Rodeo Refinery, DEIR Figure 3-4, shows "SMGO" entering the Refinery at the U-240 Prefractionator unit (Prefrac unit). DEIR, p. 3-12 ("Heavy gas oil (HGO) streams from Unit 200 and HGO purchased from outside of the Refinery are fractionated in the Unit 240 prefractionator."). SMGO is Santa Maria Gas Oil. This DEIR figure is reproduced here as Figure 1 for ease of reference. The U-240 Prefrac unit separates Santa Maria gas oil and other gas oils into lighter hydrocarbon fractions that are currently blended into the Refinery Fuel Gas, shown in Figure 3-5 (see lower left hand corner, blue arrow labeled U-240/244/248 S-RFG being routed to U-240 Fuel Gas Treating), but which will be further processed into propane and butane in new units added to the Rodeo Refinery as part of the Project.

Figure 1
Overall Existing Refinery Block Flow Diagram

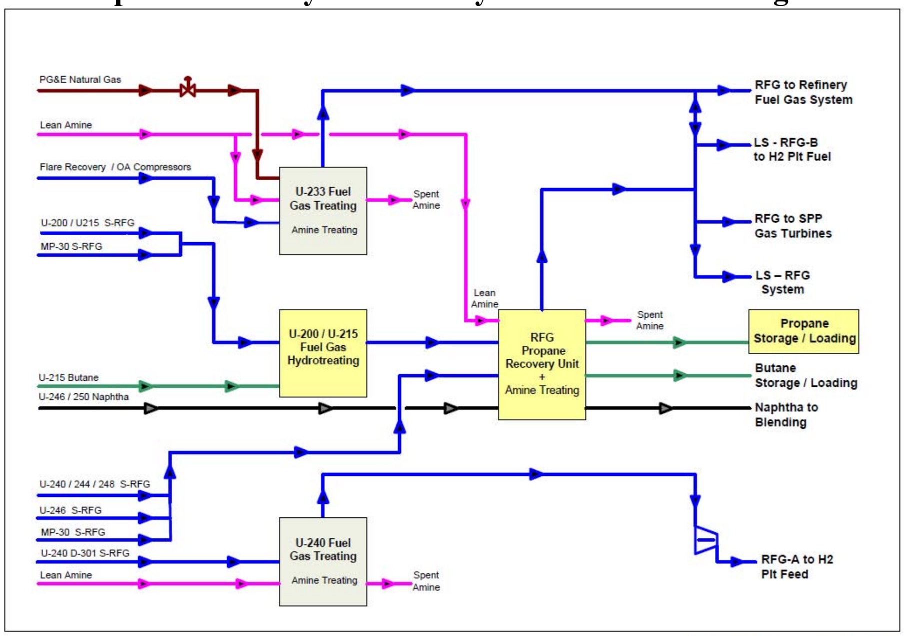


SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-4
Overall Block Flow Diagram of Refinery

Under the Project, the output from the Prefrac unit is sent to the proposed "RFG Propane Recovery Unit" instead of the Refinery Fuel Gas system. This unit is the heart of the subject Project and is immediately adjacent to the Unit 240 Prefrac unit. DEIR, Table 3-2. Propane and butane are recovered in this unit. This new propane/butane extraction unit is shown in DEIR Figure 3-6, which is reproduced here as Figure 2 for ease of reference.

Figure 2
Proposed Refinery Fuel Gas System Block Flow Diagram



SOURCE: Phillips 66 Company

Phillips 66 Propane Recovery Project . 120546
Figure 3-6
Proposed Refinery Fuel Gas System Block Flow Diagram

The RFG Propane Recovery Unit is the big yellow box in the middle of Figure 2. Blue arrows in the lower left hand corner of Figure 2 identify the inputs to this unit, which are various refinery streams. These streams include "U-240/244/248 S-RFG." This designation means that Refinery Fuel Gas (RFG) from Unit U-240 is sent to the RFG Propane Recovery Unit. (This stream was formerly sent to the U-240 Fuel Gas Treating Unit. DEIR, Fig. 3-5.) As Santa Maria Gas Oil (SMGO) is one of the inputs to Unit U-240, changes at the Santa Maria Facility would be transmitted directly to the Project via the U-240 Prefrac Unit.

This establishes a direct link between this Project and modifications at the Santa Maria Facility. This is the "nexus" to the larger project with the potential to change crude oil feedstocks.

The increase in throughput at the Santa Maria Facility would increase the amount of SMGO processed at Rodeo into propane and butane. The new rail spur at the Santa Maria Facility would enable tar sands crudes to be imported to and processed at Santa Maria and/or shipped directly to Rodeo. As discussed below, tar sands crudes imported by rail are blended with a diluent that is rich in butane and propane. Thus, both projects proposed for the Santa Maria Facility will have a direct impact on the amount of propane and butane available for recovery at Rodeo, making up any deficit based on the Rodeo baseline crude slate. The baseline crude slate and feedstocks to the propane/butane recovery Project are not disclosed so this link and its impact on emissions would never be discovered and thus not mitigated.

Thus, there is both a direct pipeline link between the two facilities, an explicit statement that the SMF throughput project was developed to send more semi-refined product to the Rodeo Refinery, and a direct process link between those products and the input to the propane/butane recovery Project disclosed on the process flow diagrams for the Project. These three factors establish a nexus between the propane/butane Project and modifications at the Santa Maria Facility. Thus, these two projects are integrally related and should have been evaluated as a single project.

Additional propane/butane-rich feedstock could be obtained by importing certain classes of cost-advantaged tar sands crudes. These tar sands and other cost-advantaged crudes are cost advantaged because they are stranded, with no pipeline access and thus must be delivered by rail.[12] However, refineries are not equipped to take delivery of large amounts of crude by rail, which requires large unit trains that require significant infrastructure improvements.

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.[13] The diluent can be readily separated and recovered as propane/butane at Rodeo.

Cost-advantaged crude sells at a discount relative to crude oils tied to the global benchmark, North Sea Brent crude. Many of these cost-advantaged crudes are rich in fractions that would increase the yield of butane and propane[14] at the Rodeo Refinery. Based on analyses by one of Phillips' competitors, Western Canadian Select (WCS) was identified as one of the most cost-advantaged crude for direct rail import to California.[15] Western Canadian Select is a tar sands DilBit that contains 2% butane and 4.3% pentane.[16]

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[12] Small amounts of Canadian tar sands crudes are currently arriving on the west coast by ship. However, the pipeline capacity to transport the tar sands crude to the west coast and the rail capacity to transport it to the west coast for subsequent water delivery is currently very limited. However, projects are underway to alleviate these bottlenecks, including a Phillips 66 project at its Ferndale facility in Washington. The Ferndale project would allow direct import of tar sands crude at the Rodeo Marine Terminal.

[13] 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.

[14] See, for example, 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.

[15] Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 10, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx. provided as Appendix D to TGG Comments.

[16] Crude Monitor, Western Canadian Select, Available at: http://www.crudemonitor.ca/crude.php?acr=WCS.

Cost-advantaged crudes could reach Rodeo by rail starting at the Phillips 66 Ferndale Marine Terminal and then barged down the Pacific coast to the Phillips 66 Rodeo Marine Terminal; by rail to Santa Maria and then by pipeline to Rodeo; or by rail or barge to the nearby Pittsburg terminal.[17] However, the Phillips 66 refineries are not equipped to accept large volumes of crude by rail. Thus, Phillips 66 is currently permitting projects to achieve both of these goals.[18]

An expansion of the Phillips 66 Marine Terminal at Rodeo was recently permitted to allow an increase of crude oil imported by ship by 20,500 BBP, from 30,682 BPD at present to 51,182 BPD.[19] Phillips 66 was recently issued a permit to construct a new crude rail unloading facility at its Ferndale Refinery in Washington to increase rail shipments of cheap Canadian tar sands crudes. This rail terminal would allow it to import tar sands crude by rail and barge them down the Pacific coast to Rodeo.[20 21]

The Phillips 66 rail spur extension project at the Santa Maria Facility would allow the import of a "full range of competitively priced crude oil." Rail Spur Land Use Ap., Appx. A, pdf 18. Phillips has admitted that these "competitively priced crude oils" include Canadian tar sands crudes. These crudes would be processed at the Santa Maria Facility, which sends its semi-refined products to Rodeo. The SMF is permitted to process up to 49,950 BPD of crude. SMF FEIR, p. 1-1. The rail spur project would allow the import of 37,000 BPD of "competitively priced crude oils", or 74% of its throughput. Rail Project IS,[22] pp. 15, 22. This means that one of the feedstocks for the propane/butane recovery Project would be significantly modified by the Santa Maria rail spur project to include tar sands crude, which would include propane/butane rich DilBits.

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[17] Phillips 66 Delivers on Advantaged Crude Strategy, Available at: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx.

[18] Phillips 66 Delivers on Advantaged Crude Strategy, Available at: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx.

[19] Bay Area Air Quality Management District, CEQA Initial Study, Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Applications 22904, December 2012.

[20] Northwest Clean Air Agency, Order of Approval to Construct (OAC) 1152, Crude Unloading Facility, Phillips 66 Ferndale Refinery, June 7, 2013. See also: Thomson Reuters: "Phillips 66 Seeks Permit for Facility to Receive Crude by Rail", April 3, 2013, Available at: http://www.4-traders.com/PHILLIPS-66-10447684/news/Phillips-66-seeks-permit-for-facility-to-receive-crude-by-rail-16604359/.

[21] In addition, crude oil will either be received by or delivered to a new facility located in Pittsburg, California. 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 Rodeo. WesPac RDEIR, p. 2.0-1. All products handled at the facility would be transported by rail, ship, barge, or pipeline. Id. 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 BBLs per day. Id., p. 2.0-2. 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. *Id*.

[22] Arcadis, Applicant's Reference CEQA IS, Santa Maria Refinery Rail Project, June 2013 (Rail Project IS").

While the DEIR did not acknowledge the relationship between the subject Project and the rail spur extension project, the FEIR does mention the existence of the rail spur extension project at Santa Maria, but claims, with no support, that the crudes imported would be only from "domestic sources available in the marketplace." FEIR, p. 2-4. This contradicts the rail spur project description, which describes the project as allowing the import of a "full range of competitively priced crude oil," not just "domestic" sources. I am not aware of anything in the record for the Santa Maria rail spur extension project that would limit imported crude to just "domestic" sources. This contradicts not only the record in that case, but also public statements to the contrary by Phillips 66. Further, the FEIR does not evaluate the rail spur's environmental impacts at Rodeo, which are potentially significant, as discussed below and in Attachment 2 (my comments on Valero).

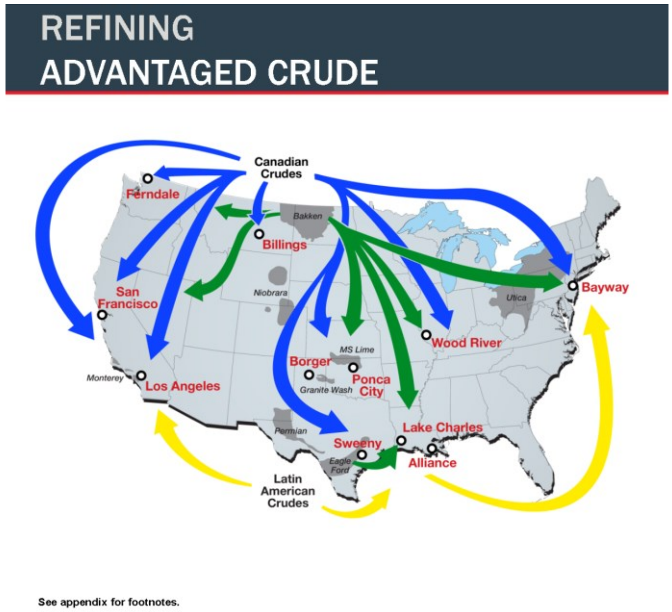
In a September 2013 presentation, Greg Garland, Chairman and CEO of Phillips 66, stated Phillips 66 plans to import "cost advantaged" crude from Canada to its refineries in California as illustrated in Figure 3. Garland stated: "Our real challenge that we have or opportunity that we have is to get advantaged crudes to the East Coast and West Coast. So we're working that in terms of moving Canadian crudes down into California or building rail facilities. We're looking at rail to barge to ship, down to the West Coast refineries...."[23]

In a May 2013 presentation, Phillips EVP Tim Taylor stated in response to a question on bringing heavy Canadian crude oil into California that "Today, we are doing some barge movements down the coast into California on heavy Canadian. You can look in the Northwest to do that. So that's an option that we're going to continue to use and we're looking at expanding that opportunity with some of the logistics things we're putting in place. We're also continuing to move crude by rail in smaller amounts into California and looking at projects really to increase that as well."[24]

[23] September 12, 2013 Transcript, pdf 7: Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/Barclays_091213_Final.pdf

[24] May 31, 2013 Transcript, pdf 13, Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/PSX-Transcript-2013-05-01.pdf

Figure 3[25]



III. THE PROJECT DESCRIPTION IS INCOMPLETE

The information included in the DEIR is not adequate to identify and assess all of the impacts of the Project. There are two major classes of omissions.

First, the DEIR did not disclose that the Project would occur at a refinery that is linked by pipeline to a separate facility, the Santa Maria Facility, that will supply part of the feedstock proposed to be recovered as propane/butane. The FEIR acknowledges this link in response to comments. FEIR, Master Response 2.2, However, the FEIR continues to ignore the environmental impacts resulting from the link between modifications currently under way or proposed at the Santa Maria Facility and this Project. The link is established above in Comment II.

The failure to disclose this link, via Santa Maria gas oil which is converted into propane and butane at Rodeo by the Project, is a serious omission. The changes proposed and underway at the Santa Maria Facility will increase both the amount and composition of the feedstocks recovered as propane and butane at the Rodeo Refinery. These changes in feedstock amount and composition would result in significant air quality and public health impacts at Rodeo.

The FEIR asserts that "a company's purchase of raw materials is a business activity and not a CEQA project or action that would require a discretionary permit or approval by the County." FEIR, p. 3.2-118. This is incorrect. The chemical composition of the raw materials that are processed by a refinery directly affect the amount and

[25] Greg Garlands, Phillips 66, Barclays Conference, pdf 24, Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/barclays2013_finalv2.pdf.

composition of emissions from that refinery. The amount and composition of sulfur in the crude slate, for example, ultimately determines the amount of SO2 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.

In particular, the feedstocks that could arrive at the Rodeo Refinery for recovery as propane and butane may include tar sands crudes blended with diluents or "DilBits." These DilBits contain significant amounts of hazardous air pollutants, such as benzene, a potent carcinogen. These would be emitted at many fugitive components in the Refinery, including compressors, pumps, valves, fittings, and tanks, in greater amounts than from baseline feedstock.

These increased emissions would result in significant public health and air quality impacts not addressed in the DEIR nor the FEIR. These include significant increases in volatile organic compounds (VOCs) emissions not otherwise included in the emission estimates; hazardous air pollutants, including benzene, which could cause significant health impacts; and highly odiferous sulfur compounds that would individually and cumulatively cause malodors, degrade ambient air quality, increase the incidence of accidental releases, and adversely affect the health of workers and residents around the Refinery. Further, the high acid levels in these crudes and their semi-refined products would accelerate corrosion of refinery components, contributing to equipment failure and increased accidental releases.

Second, the DEIR failed to disclose that the Project would reduce the heat content of the refinery fuel gas from 1340 Btu/scf (British thermal unit per Standard Cubic Feet) (BAAQMD Permit Ap., p. 10) to 1050 MMBtu (one million Btu) (5/13/13 BAAQMD Notes). This is a 30% drop in the heat content of the fuel for all refinery fuel gas-fired sources within the Rodeo Refinery. Notes in the BAAQMD's files indicates that this will require replacing the burners in at least 19 process heaters. 5/13/13 BAAQMD Notes.

The DEIR did not disclose this dramatic decline in fuel gas heat content or the related changes in equipment that would be required to burn the altered refinery fuel gas. The FEIR concedes a decline in heat content in response to comments but fails to disclose the magnitude of the decline. However, the FEIR asserts with no analysis that "removal of propane and butane from the system and replacing it with natural gas would not affect the performance of combustion devices at the Refinery." FEIR, p. 3.2-130. The affected combustion units and burner configurations were not identified and baseline emissions were not disclosed. Thus, there is no basis for this claim.

The FEIR argues that the types of changes that would be made to heaters are considered by the BAAQMD to be an "alteration" rather than a "modification" as there would be no emission increase. FEIR, p. 3.2-130. However, the BAAQMD definition of "alteration" is irrelevant for purposes of CEQA. The EIR must identify the change in emissions from the affected combustion units and burner configurations.

A large drop in fuel heat content can affect the combustion efficiency of all combustion sources, including heaters, boilers, and turbines. A related concern is a concomitant drop in flame temperature. The Project basically involves replacing propane and butane that are currently part of the Refinery Fuel Gas (RFG) with natural gas. Propane and butane burn with a hotter flame than natural gas.[26] These two effects, a large drop in heat content and a lower flame temperature, would result in an increase in the emission of products of incomplete combustion, including hazardous air pollutants, carbon monoxide, and reactive organic gases from all fuel gas fired combustion sources. None of these pollutants are routinely monitored, e.g., with continuous emission monitoring systems, and some are not monitored at all (HAPs). Thus, the increases would not even be detected until after the fact. The DEIR and FEIR did not disclose the flame temperature issue. Further, only 19 process heaters would receive upgraded burners. The FEIR is silent on the impacts that would result from the lower heat content fuel and lower resulting flame temperature at other combustion sources that will not be upgraded.

The DEIR should be revised to include a complete description of the Project and an analysis of all of the environmental effects of these changes.

IV. PROJECT EMISSIONS ARE UNDERESTIMATED AND SIGNIFICANT

The DEIR underestimated the increase in greenhouse gas (GHG) emissions and criteria pollutant emissions (NOx, ROG, PM2.5/PM10) that would result from the Project. If the EIR had accurately estimated the Project's emissions, it would have determined that the Project will result in significant unmitigated air quality impacts from emissions of GHGs, NOx, and ROG. The DEIR also failed to estimate the increase in carbon monoxide emissions that would result from the Project.

IV.A. Greenhouse Gas Emissions (GHG) Are Underestimated

The DEIR estimated that the Project would decrease GHG emissions by 325,978 metric tons per year (MT/yr). DEIR, Table 4.8-3. The increases in GHG emissions from a new boiler (67,133 MT/yr), additional natural gas combustion (592,761 MT/yr), and other miscellaneous sources (7,372 MT/yr) are assumed to be offset by removing 14,500 BPD of butane and propane from the fuel gas system and replacing it with natural gas, which emits less GHG (-759,244 MT/yr) and the shutdown of Plant 4 Hydrogen Plant and B-401 Process Heater (-234,000 MT/yr). These reductions are not supported and are incorrect. When the errors discussed below are corrected, GHG emissions exceed the significance threshold of 10,000 MT/yr for stationary sources and 1,100 MT/yr for other types of projects (DEIR, p. 4.8-13). Thus, they are a significant unmitigated impact of the Project.

[26] Flame Temperatures of Some Common Gases, Available at; http://www.engineeringtoolbox.com/flame-temperatures-gases-d_422.html.

1. Reduction: Removing Butane and Propane from Fuel Gas

The Project would remove 14,500 BPD of butane and propane from the refinery fuel gas system and replace it with natural gas. As propane and butane generate more GHG emissions when burned than natural gas, this results in a net decrease in GHG emissions at the Refinery of 166,483 MT/yr (592,761 -759,244 = -166,483 MT/yr). DEIR, Table 4.8-3.

However, a reduction would only occur if the propane/butane are not used as fuel, which is their usual end use. The DEIR fails to disclose the use of the removed butane and propane. This undisclosed use could result in indirect impacts that were not considered in the DEIR. Butane and propane, for example, are fuels, often called liquefied petroleum gas or LPG. They are also feedstocks to various chemical processes. Either use would result in GHG emissions.

First, some, perhaps all, of the recovered butane and propane could be sold within California for use as fuel, where CEQA clearly applies to 100% of the resulting GHG emissions. If sold as fuel to customers in California, the resulting emissions are indirect emissions from the Project and must be included in the Project GHG emission inventory. Correspondence in the BAAQMD file indicates that ". . . some past (and current) butane deliveries have included local industrial customers within Contra Costa and Alameda counties." 4/30/13 Phillips Response Letter,[27] p. 10, Response to Comment #15. Thus, absent a condition of certification prohibiting the sale of propane and butane for any use in California that would generate GHG, 100% of the GHG emissions from burning propane and butane, the most likely end use, must be included in the EIR's GHG impact analysis. This one modification results in an increase in GHG emissions of 433,266 MT/yr from the Project.[28] This is a significant unmitigated impact of the Project.

Second, even assuming 100% of the propane and butane were burned or otherwise used outside of California in a manner that generated GHG, these emissions would still result in significant adverse impacts on California as GHG is a global pollutant, widely acknowledged to affect climate change worldwide, regardless of release point. The GHG emissions released in neighboring states, for example, would contribute to sea level rise along the California coast; loss in California's snow pack, leading to floods and droughts; and more high ozone days in California. DEIR, pp. 4.8-1/2.

Under this view, the Project is exporting its significant GHG impact to neighboring states, where it continues to impact global climate and thus California. Therefore, regardless of where the propane and butane are actually used, the environmental consequences of its use are the same and must be considered.

[27] Letter from Don Bristol, Phillips 66, to Brian Lusher, BAAQMD, Re: Response to Incomplete Letter 3/1/13, April 30, 2013 (4/30/13 Phillips Response Letter).

[28] Revised GHG emissions based on DEIR Table 4.8-3: -325,978 + 759,244 = **433,266 MT/yr**.

Thus, the DEIR implicitly assumes that the propane and butane removed from the refinery fuel gas will not be used in a manner that generates GHG and ignores the impacts of this use.

2. Relative Proportions of Propane and Butane

The GHG emissions were estimated assuming the production of 4,200 BPD of propane and 3,800 BPD of butane. Butane generates about 6% more GHG than propane per gallon burned. GHG Supplement, Nov. 2012, p. 4. In correspondence with the BAAQMD, Phillips has requested a lump-sum limit of 14,500 BPD (6/28/13 Phillips Response Letter, p. 5, Response to Comment #6), which would allow them to produce 100% butane, increasing GHG emissions compared to those estimated in the DEIR.

3. Reduction: Hydrogen Plant and Heater Shutdown

The GHG emission calculation additionally assumes a net reduction of 234,000 MT/yr from the shutdown of the Plant 4 Hydrogen Plant and the Unit 240 Process Heater B-401. DEIR, p. 4.3-13 and Table 4.8-3. The DEIR asserts that the GHG reduction corresponds to the 3-year average baseline GHG emissions from these units and cited ERM 2013. DEIR, p. 4.8-12. However, the DEIR references indicate that ERM 2013 is the BAAQMD Authority to Construct Application. DEIR, p. 9-8. I reviewed this document. It does not contain any support for the claimed reductions from shutting down these units. I was unable to find any support for these reductions in any of the documents that I reviewed and thus was unable to confirm whether they were correctly calculated. Regardless, the subject units were reportedly shutdown in 2011, which is part of the CEQA baseline. Thus, these reductions cannot be claimed as mitigation for Project increases.

My inability to find any support for these GHG emissions is consistent with comments filed by BAAQMD staff on the DEIR. They were also unable to find any support for the claimed GHG reductions from decommissioning a process heater and hydrogen plant. The BAAQMD further expressed concern that "emission from Unit 240 [the shutdown process heaters] may have shifted to other existing equipment due to increased operating demand." Increased heat demand, for example, would result from recovering butane and propane for the Project and upgrading additional semi-refined materials from the Santa Maria Facility. Further, the DEIR and the record supporting it do not contain any evidence that the emission reductions are permanent, real, and quantifiable.[29]

The FEIR responded to the BAAQMD's comments, asserting that the "GHG-related offsets that would be associated with the B-401 process heater are presented in the DEIR for informational purposes only and are not required to reduce the GHG emissions impact to a less-than-significant level." FEIR, p. 3.1-24. However, this is true only when considered in isolation, without acknowledging the increase in GHG emissions from burning the propane and butane removed from the refinery fuel gas. Further, this FEIR

[29] Letter from Jean Roggenkamp, BAAQMD, to Lashun Cross, CCC Dept. of Conservation and Development, Re: Phillips 66 Company Propane Recovery Project DEIR, August 6, 2013.

response also fails to provide any support for the GHG reductions from these shutdown unit.

If the GHG reductions from both the Plant 4 Hydrogen Plant and B-401 Process Heater Shutdown are removed from the GHG inventory in DEIR Table 4.8-3 and the increase in emissions from burning the propane and butane are added, the net increase in GHG emissions based on DEIR Table 4.8-3 would be 1.3 million MT/yr (-325,978+234,000 + 759,244 = 1,319,222 MT/yr). These emissions exceed the CEQA significance threshold by a vast amount and are highly significant.

IV.B. Criteria Pollutant Emissions Are Underestimated

The DEIR estimated daily and annual Project operational emissions for nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM10 and PM2.5), and reactive organic gases (ROG). DEIR, Tables 4.3-6 and 4.3-7. The resulting emissions were compared to the BAAQMD's daily and annual CEQA significance thresholds for NOx, PM10, PM2.5, and ROG. No significance threshold was proposed for SO2 and carbon monoxide (CO) was omitted from DEIR's analyses completely.

The emissions that were estimated in the DEIR and remain unchanged in the FEIR are underestimated for two reasons, discussed below. When the errors in the emission calculations are corrected, the resulting increases in daily and annual NOx and ROG emissions exceed both the daily and annual CEQA significance thresholds. These are significant air quality impacts that were not identified or mitigated in the DEIR or FEIR.

1. Relies on Invalid NOx Emission Reductions

The DEIR's daily and annual NOx emission analysis relies on NOx emission reductions from shutting down Process Heater B-401. DEIR, Tables 4.3-6 and 4.3-7. These reductions occurred in 2011, during the CEQA baseline. Therefore, they are part of the baseline and not available to offset Project NOx increases. The increase in the DEIR's estimate of both daily (99.2 lb/day >54 lb/day) and annual NOx emissions (13.9 ton/yr > 10 ton/yr) exceed CEQA significance thresholds without these Process Heater B-401 reductions and are thus significant unmitigated impacts of the Project.

2. Excludes Locomotive Emissions Outside of the BAAQMD

Notwithstanding the use of invalid NOx offsets, the increase in NOx emissions are even higher than disclosed in the DEIR. The locomotives used to transport recovered propane and butane from the Refinery to market are the major source of NOx emissions (>70% of total Project emissions) and an important contributor to ROG emissions (8%). DEIR, Tables 4.3-6 and 4.3-7. These emissions were underestimated by only counting emissions released within the boundary of the BAAQMD, rather than the entire distance the locomotives will travel within California. DEIR, p. 4.3-20. CEQA covers at least all emissions released within the State and in some cases, emissions released outside of the State that impact in-State values.

The total rail track length within the BAAQMD used to calculate locomotive emissions in DEIR Tables 4.3-6 and 4.3-7 was 67 miles one way (AQS Attach. 1,[30] pdf 15) based on 50% of the trains using the Union Pacific route and 50% using the BNSF route. The total track length to the California-Arizona border used to calculate GHG emissions is 659 miles one way, based on the same 50/50 assumption. DEIR, p. 4.8-16 and AQS Attach. 1, pdf 15.

I revised the locomotive linehaul emissions for NOx and ROG using the total track length within California, but otherwise using all of the DEIR's assumptions. The results of my calculations are shown in Table 1. The criteria pollutant emissions from locomotive linehaul (which is only part of the total locomotive emissions) are significantly higher than disclosed in the DEIR, as shown in Table 1. This increase alone is sufficient to tip NOx emissions over the BAAQMD daily and annual significance thresholds, even assuming the invalid boiler NOx emission offsets.

Table 1
Revised Locomotive Linehaul Emissions

	DEIR[31] (lb/day)	Rev. [32] (lb/day)	Sig. Criteria (lb/day)	DEIR[31] (ton/yr)	Rev.[32] (ton/yr)	Sig. Criteria (ton/yr)
NOx	76.03	**580**	54	9.84	**72**	10
ROG	3.63	**27**	54	0.47	3.5	10

Note: **bold** indicates a revised locomotive linehaul emission rate that exceed the significance threshold all by itself, without considering increases from any other sources.

These revised emissions combined with all other claimed emission increases and decreases as reported in the DEIR, Tables 4.3-6 and 4.3-7, exceed the BAAQMD significance thresholds for both daily and annual NOx and ROG emissions, as explained below.

The net increase in daily NOx emissions, including the revised locomotive linehaul emissions of 580 lb/day and the invalid NOx offsets, is 541 lb/day.[33] These emissions exceed the NOx daily significance threshold of 54 lb/day by a factor of ten. DEIR, Table 4.3-6.

Similarly, the net increase in annual NOx emissions, including the revised locomotive linehaul emissions of 72 ton/yr and the invalid NOx offsets, is 66 ton/yr.[34]

[30] Phillips 66, Rodeo Propane Recovery Project, Air Quality Supplement, Attachment 1, Criteria Pollutant and GHG Emissions, November 2012 (AQS Attach. 1).

[31] AQS Attach. 1, pdf 1.

[32] From AQS Attach. 1, pdf 19 (lb/day) and pdf 20 (ton/yr): Linehaul emissions within California = small line haul from Richmond terminal to refinery + large linehaul from California border to Richmond terminal. For NOx in lbs/day: 18.97 + 57.06(659/67) = **580.2 lb/day** or **72.7 ton/yr**. For ROG: 0.97 +2.65(659/67) = **27.1 lb/day** or **3.47 ton/yr**.

[33] Total revised daily NOx emissions : 20.4 + (79.0-76.03) + 580 - 62.3 = **541.1 lb/day.**

[34] Total revised annual NOx emissions : 3.7 + (10.2-9.84) + 72.7 - 10.8 = **65.96 ton/yr.**

This exceeds the NOx annual significance threshold by a factor of six. DEIR, Table 4.3-6.

The DEIR indicates the shutdown of Process Heater B-401 reduced daily NOx emissions by 244 lb/day (DEIR, Table 4.3-4). The DEIR also indicates the shutdown of Process Heater B-401 reduced annual NOx emissions by 44 ton/yr. DEIR, Table 4.3-4. However, even assuming 100% of these shutdown emissions were available for the Project, they would not be adequate to offset the daily increases in linehaul NOx emissions as calculated in Table 1. Regardless, 100% of Process Heater B-401 NOx reductions are not available as some of them (33.16 ton/yr) were used to offset NOx emission increases of the Marine Terminal Offload Limit Project. Marine Terminal IS, Table 3.3-2.

The DEIR suggests by omission that more NOx offsets are available than were relied on in Tables 4.3-6 and 4.3-7 by presenting the full boiler shutdown amount without disclosing that most had already been used. The FEIR clarifies that the balance of the NOx reductions from the Process Heater B-401 shutdown, not relied on in Tables 4.3-6 and 4.3-7, were used to offset increases associated with the Marine Terminal Project. FEIR, pp. 3.1-24/25. They are not available to offset the additional increase in NOx emissions resulting from the increase in locomotive linehaul emissions as calculated in Table 1, assuming the full transit distance within California. Thus, the revised increase in daily and annual NOx emissions are a significant unmitigated air quality impact when the correct travel distance of locomotives is used to estimate emissions.

The increase in daily ROG emissions from all Project sources, including the revised locomotive linehaul emissions, is 70.4 lb/day,[35] which exceeds the ROG daily significance threshold of 54 lb/day by 30%. Similarly, the increase in annual ROG emissions from all Project sources, including the revised locomotive linehaul emissions is 11.4 ton/yr,[36] which exceeds the ROG annual significance threshold of 10 ton/yr. Thus, daily and annual ROG emissions from the Project are significant unmitigated air quality impacts that were not disclosed in the DEIR when the correct travel distance of locomotives is used to estimate emissions.

Finally, even if emissions were based only on the track length within the BAAQMD, rather than the entire State, the Project would still exceed the NOx daily significance threshold if the actual UP track length going south out of the District (90 miles) was used in the calculations, rather than the average of the UP and BNSF track lengths (67 miles). The distance to the eastern boundary of the District is 44 miles and to the southern boundary, 90 miles. The 67 miles used in the DEIR's linehaul emission calculations is the average of these two (90+44/2 = 67). 6/28/13 Phillips Response Letter, p. 12, Response to Comment #15. However, nothing in the EIR would prevent 100% of the trains from using the UP track going south out of the District. The daily

[35] Total revised daily ROG emissions : 18.1 + 25.1 + (3.8-3.63) + 27 = **70.4 lb/day.**

[36] Total revised annual ROG emissions : 3.3 + 4.6 + (0.5-0.47) + 3.5 = **11.4 ton/yr.**

NOx emission increase, assuming the UP track length of 90 miles within the District would be 57 lb/day, which exceeds the CEQA significance threshold of 54 lb/day.[37]

3. Underestimates Steam Boiler Emissions

The DEIR emission estimates assumed a new 140 MMBtu/hr boiler would be required to supply steam for the Project. The net emission calculations in Comment IV.B.2 that correct the linehaul underestimate assume this new boiler. However, during BAAQMD permitting, Phillips 66 removed the new 140 MMBtu/hr boiler and revised the emissions to assume steam demand would be met by using surplus low pressure steam, improving efficiency of existing steam consumers, and by increasing high pressure steam production at the Steam Power Plant. This resulted in a reduction in emissions from supplying steam, compared to emissions claimed in the DEIR. 4/30/13 Phillips Response Letter, p. 4, Response to Comment #7.

However, these changes disclosed in the BAAQMD permitting file are small, compared to increases from other Project components in the DEIR, and thus do not materially affect any of the conclusions in Comment IV.B.2. Further, as discussed below in Comment IV.C.3, the NOx emissions from supplying steam at the Steam Power Plant are actually significantly higher than claimed in the Phillips permitting application (15.6 ton/yr compared to only 3.7 ton/yr assumed in the DEIR). See Comment IV.C.3. These revised emissions alone are sufficient by themselves to exceed the BAAQMD NOx annual significance threshold.

IV.C. Other Emissions from The Project Are Omitted

The DEIR estimated emissions from new equipment that would be added by the Project plus certain associated mobile source emissions, including a new boiler, tanks and piping, locomotives, and truck and commuter trips. The locomotive emissions are discussed in Comment IV.B.2. DEIR, Tables 4.3-6 & 4.3-7, p. 4.3-21.

The equipment required to recover propane and butane from the refinery fuel gases and to remove sulfur from the recovered products requires various inputs to operate. This results in increases in emissions above the CEQA baseline that were not included in the DEIR's analysis. These include: (1) use of the recovered propane and butane elsewhere in California; (2) electricity; (3) hydrogen; (4) emissions from increased sulfur removal; and (4) certain increases in emissions from generating steam at the existing Steam Plant to support the Project. Each omitted emission source is discussed below.

The BAAQMD files indicate that Phillips conceded there would be an increase in the throughput of the Air Liquide Hydrogen Plant and an increase in the Sulfur Recovery

[37] From AQS Attach. 1, pdf 19 (lb/day): Linehaul emissions within California = small line haul from Richmond terminal to refinery + large linehaul from boundary of BAAQMD to Richmond terminal. Linehaul emissions for NOx in lbs/day: 18.97 + 57.06(90/67) = **95.6 lb/day.** The net increase = 20.4 + (79.0-76.03) + 95.6 - 62.3 = or **56.7 lb/day** > 54 lb/day.

Units, but in both cases, less than the permitted levels.[38] However, for purposes of CEQA compliance, the permitted levels are not material, but rather the increase relative to a historic baseline. These emissions were not included in the Project totals.

1. Propane/Butane Combustion In California

The DEIR failed to include criteria pollutant emissions from burning or otherwise using the recovered propane/butane anywhere. The recovered propane/butane is being produced to meet commercial-grade standards with less than 5 ppm hydrogen sulfide (H_2S). 6/28/13 Phillips Response Letter, p. 2. Commercial-grade propane is used as a fuel.[39] Thus, it is reasonably foreseeable that the produced propane/butane would be used as fuel, increasing criteria pollutant and GHG emissions.

The BAAQMD permitting file further discloses that Phillips currently sells butane from the Rodeo Refinery in California. 4/30/13 Phillips Response Letter. Thus, emissions from the use of propane/butane as a fuel within California are a reasonably foreseeable impact caused by the Project and must be evaluated. 14 Cal Code Regs. §§15064(d)(3) and 15358(a)(2).

There is nothing in the DEIR or FEIR that would prohibit Phillips from selling 100% of the recovered propane/butane for new uses as a fuel anywhere, including within California. Thus, unless the County imposes a condition requiring that 100% of the propane/butane is sold outside of the jurisdiction of CEQA or for non-combustion, non-emitting uses, the FEIR must include criteria pollutant emissions from its use and mitigate the resulting impacts, which are significant as demonstrated below.

I estimated the criteria pollutant emissions from combusting 100% of the Project's propane/butane in boilers within California. The results of my calculations are summarized in Table 2.

[38] Phillips 66 Propane Recovery Project Issues, BAAQMD Notes; Letter from Don Bristol, Phillips 66, to Brian Lusher, BAAQMD, Re: Response to Incomplete Letter 3/1/13, April 30, 2013, pp. 3 (Response to Comment #4) and 6 (Response to Comment #8).

[39] See, e.g., Tesoro Safety Data Sheet, Propane - Commercial Grade, Available at: http://www.tsocorp.com/stellent/groups/corpcomm/documents/tsocorp_documents/msdspropane.pdf.

Table 2
Emissions from Combusting Propane/Butane Within California

	Emission Factor	Emissions	
	($lb/10^3$ gal)	(lb/day)	(ton/yr)
PROPANE			
Total PM	0.7	123	22.5
N0x	13	2,293	418.5
CO	7.5	1,323	241.4
ROG	0.8	141	25.8
BUTANE			
Total PM	0.8	128	23.3
N0x	15	2,394	436.9
CO	8.4	1,341	244.7
ROG	0.9	144	26.2

Emission factors from AP-42, Table 1.5-1.
Propane: 4,200 BPD; Butane: 3,800 BPD
ROG = TOC - CH_4.

These emissions are compared with significance thresholds established in the DEIR for evaluating the operational air quality impacts of the Project (DEIR, p. 4.3-14) in Table 3. This comparison shows that the emissions from burning recovered propane and butane exceed significance thresholds for NOx, PM10, and ROG by a large margin and thus must either be mitigated or the EIR must prohibit the sale of recovered propane/butane within California for fuel. The emissions of CO are also large and significant, but the DEIR failed to establish a significance threshold for this pollutant.

Table 3
Comparison of Emissions from Combusting Propane/Butane Within California With Significance Criteria

	TOTAL EMISSIONS		SIGNIFICANCE CRITERIA	
	(lb/day)	(ton/yr)	(lb/day)	(ton/yr)
Total PM	251	45.8	82	15
N02	4,687	855.4	54	10
CO	2,664	486.1		
ROG	285	52.0	54	10

Assumes 100% of PM from combustion is PM10
DEIR, p. 4.314

2. Increase In Hydrogen

The hydrotreater that will be installed as part of the Project requires hydrogen to react with sulfur and convert it into forms that can be removed. The DEIR claims that the amount of hydrogen present in the existing gas streams is adequate to supply the increased hydrogen. DEIR, p. 3-25.

The BAAQMD questioned this assumption and asked Phillips to accept a permit condition stating no hydrogen would be used at the new hydrotreater. Phillips declined and admitted that ". . . there are short periods when hydrogen from a hydrogen plant will need to be supplied. These periods would typically be during startup of the hydrotreater catalyst system." 4/30/13 Phillips Response Letter, p. 3, Response to Comment #4. Phillips has not quantified the amount of additional hydrogen that will be required nor the resulting emissions. Hydrogen plants include a furnace and vents that are significant sources of criteria pollutant and GHG emissions, including specifically, the hydrogen plant that would supply this Project.[40] The EIR must quantify all of the emissions that would be generated as a result of the Project.

3. Increase in Steam

The DEIR disclosed that steam would be provided by either a new 140 MMBtu/hr steam boiler or by the existing Steam Power Plant (SPP). DEIR, pp. ES-5, 3-7, 3-20. The DEIR included emissions only for the new 140 MMBtu/hr boiler. DEIR, Tables 4.3-6 and 4.3-7. Since the DEIR was released, Phillips has elected to use the existing SPP to generate the required steam. The NOx emissions from the existing SPP are higher than those disclosed in the DEIR, as explained below.

Correspondence in the BAAQMD file indicates steam demand will be met by using surplus low pressure steam currently vented, improving steam generation efficiency, and by increasing high pressure steam production at the SPP. The increase in high pressure steam would be provided by increasing the firing rate of natural gas in the duct burners by 45 MMBtu/hr. It is unclear whether additional fuel would also have to be fired in the associated gas turbines.

The emissions included in the BAAQMD permit files (which vary from the emissions identified in the DEIR) are based only on increasing the firing rate of natural gas in the duct burners by 45 MMBtu/hr, and assume very low (and unsupported) emission factors. The emission factor used for NOx, for example, is 0.017 lb/MMBtu (4.5 ppm @ 15% O_2). 4/30/13 Phillips Response Letter, pp. 5-6, Response to Comment #7.

Based on my experience permitting many similar projects with duct burners, they typically emit much more NOx than assumed in the 4/30/13 Phillips calculations (4/30/13 Phillips Response Letter, pp. 5-6). Duct burner emissions are low only if they are located in a heat recovery steam generator equipped with modern selective catalytic

[40] Air Liquide, Hydrogen Plant Project, Application for Authority to Construct and Major Facility Review Permit, Rodeo, California, October 2005.

reduction to control NOx. No such arrangement is described in the DEIR (Sec. 3.3.2.9) or the original 1985 BAAQMD engineering evaluation.[41] The subject gas turbines/duct burners are permitted to emit 83 lb/hr when firing 1048 MMBtu/hr for all turbine/duct burners combined.[42] This corresponds to a NOx emission factor of 0.079 lb/MMBtu (83/1048 = 0.079). This NOx emission factor is nearly five times higher than the one used in Phillips' duct burner NOx emission calculations.

Using this revised emission factor to estimate NOx emissions from increased steam demand yields 15.6 ton/yr NOx (0.079 x 45 x 8760/2000 = 15.6) or four times more than disclosed in the DEIR (3.7 ton/yr) for the new 140 MMBtu/hr boiler. The originally proposed new boiler evaluated in the DEIR should be more efficient and emit less NOx, etc. than the old SPP due to use of modern technology and current Best Available Control Technology (BACT) controls such as selective catalytic reduction (SCR). The NOx emissions from supplying just the steam for the hydrotreater exceed the NOx significance threshold of 10 ton/yr and are thus a significant undisclosed air quality impact of the Project.

4. Increase In Sulfur Removal

The Project will increase the throughput of the existing Sulfur Recovery Units (SRU) by about 135 ton/yr of sulfur. DEIR, Fig. 3-6; 5/13/13 BAAQMD Notes, p. 2; 6/28/13 Phillips Response Letter, pp. 6-8, Response to Comment #8. The Refinery uses the Claus process to convert acid gas to liquid sulfur, which is sold. This involves combusting acid gas, which would increase NOx, CO, VOC and other emissions. The resulting elemental sulfur is sold, which involves truck emissions. Thus, the increase in throughput of the SRU would be accompanied by increases in combustion emissions from the Claus unit and the trucks used to transport the recovered sulfur product to market. The resulting increase in emissions was not disclosed in the DEIR or FEIR. The information in the files I reviewed is not adequate to estimate these emissions. It did not include, for example, the increase in acid gases that would be processed by the Claus unit, the criteria pollutant emission factors for the Claus furnace, or the number of additional truck trips that would be required to transport the sulfur to market.

5. Increase In Electricity Generation

The Project will require 1.28 MW electricity or 10,900 MW-hour of electricity DEIR, pp. 3-23, 3-28. The generation of this electricity at off-site facilities will increase criteria pollutant and GHG emissions that were not included in the DEIR. The information in the files I reviewed did not include any emission factors in pounds of pollutant per megawatt hour, which are required to estimate these emissions.

6. Emissions from Changes in Feedstock Quality

[41] BAAQMD, Engineering Evaluation, Union Oil Company, Gas Turbine Cogeneration Facility, November 8, 1985.

[42] Phillips 66 LPG Recovery Project, Permit Limit Summary, BAAQMD.

The currently proposed rail spur project at the Santa Maria Facility would allow the import of DilBits. These are rich in the propane/butane fractions required to supply the subject Project at the Rodeo Refinery. If said DilBits were routed directly to the Rodeo Refinery or if they were processed at Santa Maria to generate semi-refined products for Rodeo, which are feed for the propane/butane Project, this would result in public health impacts that were not disclosed in the DEIR.

DilBits contain large amounts of light material that distill below 149 C and are thus very volatile. This material can be emitted to the atmosphere from storage tanks and equipment leaks of fugitive components (pumps, compressors, valves, fittings) in much larger amounts than other heavy crudes and their byproducts that are currently processed at the Rodeo Refinery.

The diluent is a low molecular weight organic material with a high vapor pressure that contains not only propane and butane that would be recovered by the Project, but also high levels of other VOCs, sulfur compounds, and hazardous air pollutants (HAPs). These would be emitted during unloading and would be present in emissions from tanks and fugitive components. The DEIR did not disclose the potential presence of diluent and made no attempt to estimate these diluent-derived emissions.

The composition of some typical diluents/condensates used in DilBits is reported on the website, www.crudemonitor.ca.[43] The DEIR does not identify the specific diluents that would be used by the Project or even that diluents would be present. The CrudeMonitor information indicates that diluent contains very high concentrations (based on 5-year averages, v/v basis of the hazardous air pollutants benzene (7,200 ppm to 9,800 ppm); toluene (10,300 ppm to 25,300 ppm); ethyl benzene (900 ppm to 2,900 ppm); and xylenes (4,600 ppm to 23,900 ppm).

The sum of these four compounds is known as "BTEX" or benzene-toluene-ethylbenzene-xylene. The BTEX in diluent ranges from 27,000 ppm to 60,900 ppm. The BTEX in DilBits, blended from these materials, ranges from 8,000 ppm to 12,300 ppm.[44] Similarly, the BTEX in synthetic crude oils (SCOs), which also could be imported via the

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

[44] DilBits: Access Western Blend (AWB) -http://www.crudemonitor.ca/crude.php?acr=AWB; Borealis Heavy Blend (BHB) -http://www.crudemonitor.ca/crude.php?acr=BHB; Christina Dilbit Blend (CDB) - http://www.crudemonitor.ca/crude.php?acr=CDB; Cold Lake (CL) - http://www.crudemonitor.ca/crude.php?acr=CL; Peace River Heavy (PH) - http://www.crudemonitor.ca/crude.php?acr=PH; Seal Heavy (SH) - http://www.crudemonitor.ca/crude.php?acr=SH; Statoil Cheecham Blend (SCB) - http://www.crudemonitor.ca/crude.php?acr=SCB; Wabasca Heavy (WH) - http://www.crudemonitor.ca/crude.php?acr=WH; Western Canadian Select (WCS) - http://www.crudemonitor.ca/crude.php?acr=WCS; Albian Heavy Synthetic (AHS) (DilSynBit) - http://www.crudemonitor.ca/crude.php?acr=AHS.

Santa Maria rail spur project or the Ferndale Rail Terminal and barged to Rodeo, ranges from 6,100 ppm to 14,100 ppm.[45] These are very high concentrations that were not considered in the DEIR or FEIR. These levels are high enough to result in significant worker and public health impacts.

The CrudeMonitor information also indicates that these diluents contain elevated concentrations of volatile mercaptans (9.9 to 103.5 ppm), which are highly odiferous and toxic compounds that could result in significant odor and nuisance impacts. Mercaptans can be detected at concentrations substantially lower than will be present in emissions from the tanks and fugitive emission, including pumps, valves, flanges, and connectors.[46] In fact, mercaptans are added to natural gas in very tiny amounts so that the gas can be smelled to facilitate detecting leaks.

Thus, recovering propane and butane from semi-refined products generated from these tar sands crudes or from directly refining these crudes would emit VOCs, HAPs, and malodorous sulfur compounds, not found in comparable levels in conventional crudes currently handled at the Refinery. There are no restrictions on the feedstock composition nor any requirements to monitor emissions for these HAPs from tanks and leaking equipment where DilBit-blended and other light crude fraction would be handled.

7. CO Emissions Were Not Estimated

The Project would significantly increase emissions of carbon monoxide (CO), a criteria pollutant. Carbon monoxide is emitted from all combustion sources, including locomotives, trucks and commuter auto trips, steam generation, and combustion of the recovered propane and butane at fired sources. The DEIR is silent on CO emissions from the entire Project.

IV.D. Decrease in SO_2 Emissions Is Not Supported

The DEIR claims that the Project would reduce SO2 emissions by at least 50%, resulting in an SO2 emission decrease of at least 180 ton/yr. DEIR, pp. ES-2, 3-5, 4.3-19. The emission inventory in Table 4.3-7 takes credit for a reduction in SO2 emission of 172.4 ton/yr. DEIR, Table 4.3-7. The BAAQMD Permit Application made a similar claim. However, there it claimed a reduction of 174.7 ton/yr, of which 7.61 ton/yr was proposed to offset Project SO2 increases and the balance would be banked as Emission

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[45] SCOs: CNRL Light Sweet Synthetic (CNS) -http://www.crudemonitor.ca/crude.php?acr=CNS; Husky Synthetic Blend (HSB) -http://www.crudemonitor.ca/crude.php?acr=HSB; Long Lake Light Synthetic (PSC) -http://www.crudemonitor.ca/crude.php?acr=PSC; Premium Albian Synthetic (PAS) - http://www.crudemonitor.ca/crude.php?acr=PAS; Shell Synthetic Light (SSX) - http://www.crudemonitor.ca/crude.php?acr=SSX; Suncor Synthetic A (OSA) - http://www.crudemonitor.ca/crude.php?acr=OSA; Syncrude Synthetic (SYN) - http://www.crudemonitor.ca/crude.php?acr=SYN.

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

Reduction Credits. BAAQMD Permit Ap., p. 17. However, Phillips subsequently withdrew its banking application, casting doubt on its claim of a SO2 reduction.

Thus, there is no support, in either the DEIR record or the BAAQMD permitting record, for the claimed reduction in SO2 emissions. Emission reductions used to offset emission increases must be permanent, real, and quantifiable. There is no evidence that the claimed SO2 emission reductions meet any of these criteria. In fact, claimed reductions could be a myth if the Refinery feedstock is modified to include a larger proportion of higher sulfur tar sands crudes than currently refined. Such crudes could reach the Refinery via the related Santa Maria rail spur project or the Ferndale rail terminal by barge down the Pacific coast.

V. CUMULATIVE AIR QUALITY IMPACT ANALYSIS IS INADEQUATE

The DEIR included only the Marine Terminal project, the temporary boiler, and an SO2 transfer proposal in the list of cumulative projects. DEIR, Sec. 5.4.3.3. However, the DEIR and FEIR fail to disclose the cumulative impacts that would result from other currently proposed projects that would affect the amount and composition of feedstock refined at Rodeo, compared to CEQA baseline feedstock. Changes in baseline feedstock as explained in these comment, i.e., tar sands crudes such as DilBits, and increased amounts of semi-refined materials from the Santa Maria Facility, would increase emissions of all criteria pollutants and hazardous air pollutants at most all emission sources in the Refinery.

First, as discussed in Comment II, two projects are proposed at the Santa Maria Facility that would directly impact Rodeo. These would send increased amounts of gas oil and naphtha to Rodeo for processing, increasing emissions from many refining units compared to the CEQA baseline. A rail spur is also proposed for Santa Maria that would allow the import of tar sands crudes. These tar sands crudes would change the chemical composition of Rodeo feedstocks, as described in Comment IV.C.6 and Attachment 2. These feedstocks, for example, would increase emissions of hazardous air pollutants from tanks, compressors, pumps, valves and flanges throughout the Refinery. They would also increase NOx and SO2 emissions from fired sources throughout the Refinery, relative to the CEQA baseline.

Second, as also discussed in Comment II, Phillip 66's Ferndale Refinery is permitted to construct a rail terminal, which will facilitate barging tar sands crude to the Rodeo Marine Terminal. The Rodeo Marine Terminal was recently permitted to import increased amounts of crude. This would also change the chemical composition of Rodeo feedstocks, as described in Comment IV.C.6 and Attachment 2, compared to the CEQA baseline feedstock.

These directly related projects will cumulatively increase air emissions above the CEQA baseline. They must all be evaluated together in a revised DEIR to determine cumulative air quality impacts.