Technical Report by Greg Karras

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Regarding the
Phillips 66 Company Rodeo Renewed Project
Draft Environmental Impact Report,
County File No. CDLP20-0240,
State Clearinghouse No. 2020120330

Lead Agency
Contra Costa County

Contents

Scope of Review

In October 2021 Contra Costa County ("the County") made available for public review a Draft Environmental Impact Report ("DEIR") for the Phillips 66 Rodeo Renewed Project ("project"). The project would, among other things, repurpose selected petroleum refinery process units and equipment in the Rodeo Facility of the Phillips 66 San Francisco Refinery for processing lipidic (oily) biomass to produce biofuels. Prior to DEIR preparation, people in communities adjacent to the project, environmental groups, community groups, environmental justice groups and others raised numerous questions about potential environmental impacts of the project in scoping comments.

This report reviews the DEIR project description, its evaluations of potential impacts associated with emission-shifting on climate and air quality, refinery process changes on hazards, and refinery flaring on air quality, and its analysis of the project baseline.

[1] The author's curriculum vitae and publications list are appended hereto as Attachment 1.

1. PROJECT DESCRIPTION AND SCOPE

Accurate and complete description of the project is essential to accurate analysis of its potential environmental impacts. In numerous important instances, however, the DEIR does not provide this essential information. Available information that the DEIR does not disclose or describe will be necessary to evaluate potential impacts of the project.

1.1 **Type of Biofuel Technology Proposed**

Biofuels—hydrocarbons derived from biomass and burned as fuels for energy—are made via many different technologies, each of which features a different set of capabilities, limitations, and environmental consequences. <u>*See*</u> the introduction to *Changing Hydrocarbons Midstream*, appended hereto as Attachment 2, for examples.[2] [3] However, the particular biofuel technology that the project proposes to use is not identified explicitly in the DEIR. Its reference to "renewable fuels" provides experts in the field a hint, but even then, several technologies can make "renewable fuels,"[4] [5] and the DEIR does not state which is actually proposed.

Additional information is necessary to infer that, in fact, the project as proposed would use a biofuel technology called "Hydrotreated Esters and Fatty Acids" (HEFA).

1.1.1 <u>Available evidence indicates that the project would use HEFA technology</u>.

That this is a HEFA conversion project can be inferred based on several converging lines of evidence. First, the project proposes to repurpose the same hydro-conversion processing units that HEFA processing requires along with hydrogen production required by HEFA processing,[6] hydrotreating, hydrocracking and hydrogen production units.[7] Second, it does not propose to

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[2] Karras, 2021a. *Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing;* prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting. Appended hereto as Attachment 2 (Att. 2).
[3] Attachments to this report hereinafter are cited in footnotes.
[4] Karras. 2021b. *Unsustainable Aviation Fuels: An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel from repurposed crude refineries;* Natural Resources Defense Council (NRDC). Prepared for the NRDC by Greg Karras, G. Karras Consulting. Appended hereto as Attachment 3.
[5] <u>*See*</u> USDOE, 2021. *Renewable Hydrocarbon Biofuels;* U.S. Department of Energy, accessed 29 Nov 2021 at https://afdc.energy.gov/fuels/emerging_hydrocarbon.html and appended hereto as Attachment 3 ("Renewable diesel is a hydrocarbon produced through various processes such as hydrotreating, gasification, pyrolysis, and other biochemical and thermochemical technologies").
[6] Karras, 2021a (Att. 2).
[7] DEIR p.p. 3-28, 3-29 including Table 3-3 (hydrocracking units 240, hydrotreating/jet aromatics saturation units 250 and 248, and hydrogen plant Unit 110 to be repurposed) and pp. 4.3-48, 4.6-205, 4.6-210, and 4.8-257 (the onsite Air Liquide "Unit 210" hydrogen plant to be repurposed) for the project

repurpose, build or use biomass feedstock gasification,[8] which is required by commercially proven alternative renewable fuels technologies but is not needed for HEFA processing. Third, the project proposes to acquire and pretreat lipidic (oily) biomass such as vegetable oils, animal fats and their derivative oils,[9] a class of feedstocks required for HEFA processing but not for the alternative biomass gasification technologies, which is generally more expensive than the cellulosic biomass feedstocks those technologies can run.[10] Fourth, the refiner would be highly incentivized to repurpose idled refining assets for HEFA technology instead of using another "renewable" fuel technology, which would not use those assets.[11] Finally, in other settings HEFA has been widely identified as the biofuel technology that this and other crude-to-biofuel refinery conversion projects have in common.

With respect to the DEIR itself, however, people who do not already know what biofuel technology is proposed may never learn that from reading it, without digging deeply into the literature outside the document for the evidence described above.

1.1.2 Inherent capabilities and limitations of HEFA technology.

Failure to clearly identify the technology proposed is problematic for environmental review because choosing to rebuild for a particular biofuel technology will necessarily afford the project the particular capabilities of that technology while limiting the project to its inherent limitations.

A unique capability of HEFA technology is its ability to use idled petroleum refining assets for biofuel production—a crucial environmental consideration given growing climate constraints and crude refining overcapacity.[12] Another unique capability of HEFA technology is its ability to produce "drop-in" diesel biofuel that can be added to and blended with petroleum distillates in the existing liquid hydrocarbon fuels distribution and storage system, and internal combustion transportation infrastructure.[13] In this respect, the DEIR omits the basis for evaluating whether

[8] DEIR Table 3-3 (new or repurposed equipment to gasify biomass excluded).
[9] DEIR p. 3-25 ("anticipated project feedstocks ... include, but [are] not limited to" UCO [used cooking oil], FOG [fats oils and grease], tallow [animal fat], inedible corn oil, canola oil, soybean oil, other vegetable-based oils, and/or emerging and other next-generation feedstocks).
[10] Karras, 2021a (Att. 2).
[11] *Id.*
[12] *Id.*
[13] *Id.*

the project could result in combustion emission impacts by adding biofuel to the liquid combustion fuel chain infrastructure of petroleum.

Inherent limitations of HEFA technology that are important to environmental review include high process hydrogen demand, low fuels yield on feedstock—especially for jet fuel and gasoline blending components—and limited feedstock supply.[14]

The DEIR does not disclose or describe these uniquely important capabilities and limitations of HEFA technology, and thus the project. Environmental consequences of these undisclosed project capabilities and limitations are discussed throughout this report below.

1.1.3 Potential project hydrogen production technologies.

Despite the inherently high process hydrogen demand of proposed project biorefining the DEIR provides only a cursory and incomplete description of proposed and potential hydrogen supply technologies. The DEIR does not disclose that the technology used by existing onsite hydrogen plants to be repurposed by the project, fossil gas steam reforming, co-produces and emits roughly ten tons of carbon dioxide (CO_2) per ton of hydrogen supplied to project biofuel processing.[15]

The DEIR identifies a non-fossil fuel hydrogen production technology—splitting water to co-produce hydrogen and oxygen using electricity from renewable resources—then rejects this solar and wind powered alternative in favor of fossil gas steam reforming, without describing either of those hydrogen alternatives adequately to support a reasonable environmental comparison. Reading the DEIR, one would not know that electrolysis can produce zero-emission hydrogen while steam reforming emits some ten tons of CO_2 per ton of hydrogen produced.

Another hydrogen supply option is left undisclosed. The DEIR does not disclose that existing naphtha reforming units co-produce hydrogen[16] as a byproduct of their operation, or describe the potential that the reformers might be repurposed to process partially refined petroleum while supplying additional hydrogen for expanded HEFA biofuel refining onsite.[17]

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[14] Karras, 2021b (Att. 3).
[15] *Id.* (median value from multiple Bay Area refinery steam reforming plants of 9.82 g CO_2/g H_2 produced)
[16] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model, appended hereto as Attachment 5.
[17] The naphtha reformers could supply additional hydrogen for project biorefining if repurposed to process petroleum gasoline feedstocks imported to ongoing refinery petroleum storage and transfer operations.

1.2 Process Chemistry and Reaction Conditions

HEFA processing reacts lipidic (oily) biomass with hydrogen over a catalyst at high temperatures and extremely high pressures to produce deoxygenated hydrocarbons, and then restructures the hydrocarbons so that they can be burned as diesel or jet fuel.[18] The DEIR does not describe the project biofuel processing chemistry or reaction conditions; differences in HEFA refining compared with petroleum refining, impacts of feed choices and product targets in HEFA processing, or changes in the process conditions of repurposed refinery process units.[19]

1.2.1 Key differences in processing compared with petroleum refining

HEFA technology is based on four or five central process reactions which are not central to or present in crude petroleum processing. Hydrodeoxygenation (HDO) removes the oxygen that is concentrated in HEFA feeds: this reaction is not present in refining crude, which contains little or no oxygen.[20] Depropanation is a precondition for completion of the HDO reaction: a condition that is not present in crude refining but needed to free fatty acids from the triacylglycerols in HEFA feeds.[21] Saturation of the whole HEFA feed also is a precondition for complete HDO: this reaction does not proceed to the same extent in crude refining.[22] Each of those HEFA process steps react large amounts of hydrogen with the feed.[23]

Isomerization is then needed in HEFA processing to "dewax" the long straight-chain hydrocarbons from the preceding HEFA reactions in order to meet fuel specifications, and is performed in a separate process reactor: isomerization of long-chain hydrocarbons is generally absent from petroleum refining.[24] Fuel products from those HEFA process reaction steps include HEFA diesel, a much smaller volume of HEFA jet fuel (without intentional hydrocracking), and little or no gasoline: petroleum crude refining in California yields mostly gasoline with smaller but still significant volumes of diesel and jet fuel.[25] The remarkably low HEFA jet fuel yield can

[18] Karras, 2021a (Att. 2)
[19] Karras 2021a (Att. 2) and 2021b (Att. 3) provide examples of that show the DEIR could have described changes in processing chemistry and conditions that would result from the project switch to HEFA technology in relevant detail for environmental analysis. Key points the DEIR omitted are summarized in this report section.
[20] Karras, 2021a (Att. 2).
[21] *Id.*
[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] *Id.*

be boosted to roughly 49% by mass on HEFA feed, via adding intentional hydrocracking in or separately from the isomerization step, but at the expense of lower overall liquid fuels yield and a substantial further increase in the already-high hydrogen process demand of HEFA refining.[26]

None of these unique aspects of HEFA biofuel processing is described in the DEIR, though each must be evaluated for potential project impacts, as discussed below.

1.2.2 Relationships between feedstock choices, product targets and hydrogen inputs

Both HEFA feedstock choices and HEFA product targets can affect project hydrogen demand for biofuel processing significantly. Among other potential impacts, increased hydrogen production to supply project biorefining would increase CO_2 emissions as discussed in § 1.1.3. The DEIR, however, does not describe these environmentally relevant effects of project feed and product target choices on project biofuel refining.

Available information excluded from the DEIR suggests that choices between potential feedstocks identified in the DEIR[27] could result in a difference in project hydrogen demand of up to 0.97 kilograms per barrel of feed processed (kg H_2/b), with soybean oil accounting for the high end of this range.[28] Meanwhile, targeting jet fuel yield via intentional hydrocracking could increase project hydrogen demand by up to 1.99 kg H_2/b.[29] Choices of HEFA feedstock and product targets in combination could change project hydrogen demand by up to 2.81 kg H_2/b.[30]

Climate impacts that are identifiable from this undisclosed information appear significant. Looking only at hydrogen steam reforming impacts alone, at its 80,000 b/d capacity[31] the feed choice (0.97 kg H_2/b), products target (1.99 kg H_2/b), and combined effect (2.81 kg H_2/b) impacts estimated above could result in emission increments of 280,000, 569,000, and 809,000 metric tons of CO_2 emission per year, respectively, from project steam reforming alone. These potential emissions compare with the DEIR significance threshold of 10,000 metric tons/year.[32] Most significantly, even the low end of the emissions range for combined feed choice and

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[26] Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[27] DEIR p. 3-25 (identifying used cooking oil, fats oils and grease, tallow, inedible corn oil, canola oil, soybean oil, other vegetable-based oils, "and/or emerging and other next-generation" feedstocks).
[28] Karras, 2021b (Att. 3).
[29] *Id.*
[30] *Id.*
[31] An undisclosed project component would debottleneck project biorefining capacity as discussed in § 1.7 below.
[32] HEFA emission estimates based on per-barrel steam reforming CO_2 emissions from Table 5 in Attachment 3.

product target effects, for feeds identified by the DEIR and HEFA steam reforming alone, exceeds the average total carbon intensity of U.S. petroleum crude refining by 4.4 kg CO_2/b (10%) while the high end exceeds that U.S. crude refining CI by 32 kg CO_2/b (77%).[33] [34]

The DEIR project description obscures these potential impacts of the project, among others.

1.2.3 Changes in process conditions of repurposed equipment

With the sole exception of maximum fresh feed input, the DEIR does not disclose design specifications for pre-project or post-project hydro-conversion process unit temperature, pressure, recycle rate, hydrogen consumption, or any other process unit-specific operating parameter. This is especially troubling because available information suggests that the project could increase the severity of the processing environment in the reactor vessels of repurposed hydro-conversion process units significantly.

In one important example, the reactions that consume hydrogen in hydro-conversion processing are highly exothermic: they release substantial heat.[35] Further, when these reactions consume more hydrogen the exothermic reaction heat release increases, and HEFA refining consumes more hydrogen per barrel of feed than petroleum refining.[36] Hydro-conversion reactors of the types to be repurposed by the project operate at temperatures of some 575–780 ºF and pressures of some 600–2,800 pound-force per square inch in normal conditions, when processing petroleum.[37] These severe process conditions could become more severe processing HEFA feeds. The project could thus introduce new hazards. Sections 3 and 4 herein review potential process hazards and flare emission impacts which could result from the project, but yet again, information the DEIR does not disclose or describe will be essential to full impacts evaluation.

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33 *Id.*
34 Average U.S. petroleum refining carbon intensity from 2015–2017 of 41.8 kg CO_2/b crude from Attachments 2, 3.
35 Karras, 2021a (Att. 2).
36 *Id.*
37 *Id.*

1.3 Process Inputs

The project would switch the oil refinery from crude petroleum to a new and very different class of oil feeds—triacylglycerols of fatty acids. Switching to new and different feedstock has known potential to increase refinery emissions[38] and to create new and different process hazards[39] [40] and feedstock acquisition impacts.[41] Such impacts are known to be related to either the chemistries and processing characteristics of the new feeds, as discussed above, or to the types and locations of extraction activities to acquire the new feeds. However, the DEIR does not describe the chemistries, processing characteristics, or types and locations of feed extraction sufficiently to evaluate potential impacts of the proposed feedstock switch.

1.3.1 Change and variability in feedstock chemistry and processing characteristics

Differences in project processing impacts caused by differences in refinery feedstock, as discussed above, are caused by differences in the chemistries and processing characteristics among feeds that the DEIR does not disclose or describe. For example, feed-driven differences in process hydrogen demand discussed above both boost the carbon intensity of HEFA refining above that of petroleum crude refining, and boost it further still for processing one HEFA feed instead of another. The first impact is driven mainly by the uniformly high oxygen content of HEFA feedstocks, while the second—also environmentally significant, as shown—is largely driven by differences in the number of carbon double bonds among HEFA feeds.[42] This difference in chemistries among HEFA feeds which underlies that significant difference in their processing characteristics can be quantified based on available information. Charts 1.A–1.F, excerpted from Attachment 2, show the carbon double bond distributions across HEFA feeds.

The DEIR could have reported and described this information that allows for process impacts of potential project feedstock choices to be evaluated, but unfortunately, it did not.

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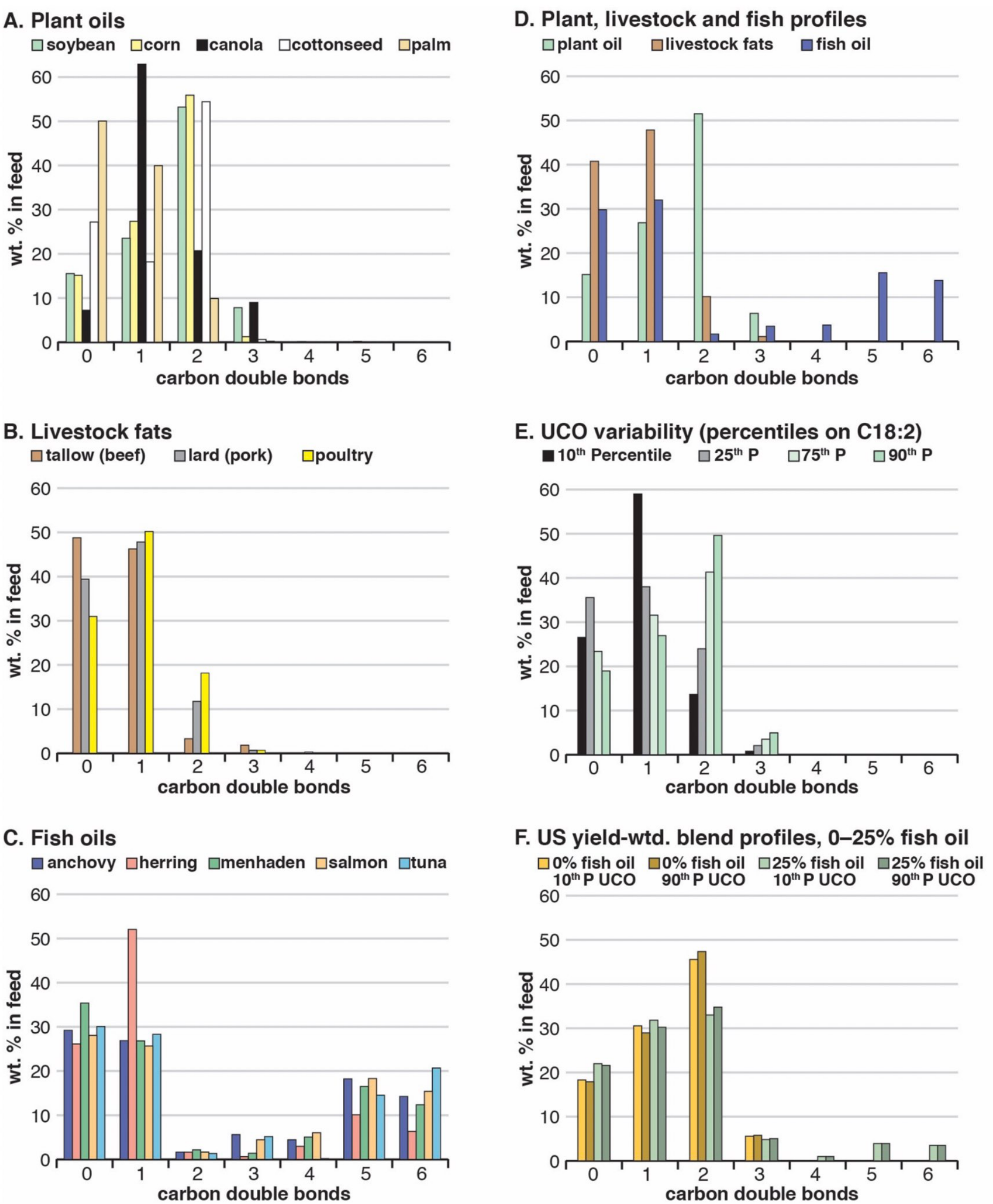
[38] See Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.
[39] See CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S. Chemical Safety Board: Washington, D.C. https://www.csb.gov/file.aspx?Documentid=5913. Appended hereto as Attachment 7.
[40] See API, 2009. *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries;* API Recommended Practice 939-C. First Edition, May 2009. American Petroleum Institute: Washington, D.C. Appended hereto as Attachment 8.
[41] See Krogh et al., 2015. *Crude Injustice on the Rails: Race and the disparate risk from oil trains in California;* Communities for a Better Environment and ForestEthics. June 2015. Appended hereto as Attachment 9.
[42] See Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).



1. HEFA feed fatty acid profiles by number of carbon double bonds.
Carbon double bonds require more hydrogen in HEFA processing. **A–C.** Plant oil, animal fat and fish oil profiles. **D.** Comparison of weighted averages for plant oils (US farm yield-wtd. 70/20/7/3 soy/corn/canola/cottonseed blend), livestock fats (40/30/30 tallow/lard/poultry blend) and fish oils (equal shares for species in Chart 1C). **E.** UCO: used cooking oil, a highly variable feed. **F.** US yield-weighted blends are 0/85/10/5 and 25/60/10/5 fish/plant/livestock/UCO oils. Profiles are median values based on wt.% of linoleic acid. *See* Table A1 for data and sources.[1]

1.3.2 Types and locations of potential project biomass feed extraction

HEFA biofuel technology is limited to lipidic (oily) feedstocks produced almost exclusively by land-based agriculture, and some of these feeds are extracted by methods that predictably cause deforestation and damage carbon sinks in Amazonia and Southeast Asia.[43] However, the DEIR does not describe the types and locations of potential project biomass feed extraction activities.

1.4 Project Scale

Despite the obvious relationship between the scale of an action and its potential environmental impacts, the DEIR does not describe the scale of the project in at least two crucial respects. First, the DEIR does not describe its scale relative to other past and currently operating projects of its kind. This omission is remarkable given that available information indicates that project is by far the largest HEFA refinery ever to be proposed or built worldwide.[44]

Second, the DEIR does not describe the scale of proposed feedstock demand. Again, the omission is remarkable. As documented in Attachment 3 hereto, total U.S. production (yield) for all uses of the specific types of lipids which also have been tapped as HEFA feedstocks—crop oils, livestock fats and, to a much lesser degree, fish oils, can be compared with the 80,000 b/d (approximately 4.25 million metric tons/year) proposed project feedstock capacity. *See* Table 1.

This feedstock supply-demand comparison (Table 1) brings into focus the scale of the project, and the related project proposed by Marathon in Martinez, emphasizing the feedstock supply limitation of HEFA technology discussed in § 1.1.2. Several points bear emphasis for context: The table shows total U.S. yields for *all uses* of lipids that also have been HEFA feedstocks, including use as food, livestock feed, pet food, and for making soap, wax, cosmetics, lubricants and pharmaceutical products, and for exports.[45] These existing uses represent commitments of finite resources, notably cropland, to human needs. Used cooking oils derived from primary sources shown are similarly spoken for and in even shorter supply. Lastly, HEFA feeds are limited to lipids (shown) while most other biofuels are not, but multiple other HEFA refineries are operating or proposed besides the two Contra Costa County projects shown.

[43] *See* Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[44] Karras, 2021a (Att. 2).
[45] Karras, 2021b (Att. 3).

Table 1. Project Feed Demand *v.* U.S. Total Yield of Primary HEFA Feed Sources for All Uses.

MM t/y: million metric tons/year

HEFA Feed-stock Type	U.S. Yield [a] (MM t/y)	Project and County-wide feedstock demand (% of U.S. Yield) Phillips 66 Project [b]	Marathon Project [b]	Both Projects
Fish oil	0.13	3269 %	1961 %	5231 %
Livestock fat	4.95	86 %	51 %	137 %
Soybean oil	10.69	40 %	24 %	64 %
Other oil crops	5.00	85 %	51 %	136 %
Total yield	20.77	20 %	12 %	33 %

a. Total U.S. production for all uses of oils and fats also used as primary sources of HEFA biofuel feedstock. Fish oil data for 2009–2019, livestock fat data from various dates, soybean oil and other oil crops data from Oct 2016–Sep 2020, from data and sources in Att. 3. **b.** Based on project demand of 4.25 MM t/y (80,000 b/d from DEIR), related project demand of 2.55 MM t/y (48,000 b/d from related project DEIR), given the typical specific gravity of soy oil and likely feed blends (0.916) from Att. 2.

In this context, the data summarized in Table 1 indicate the potential for environmental impacts. For example, since the project cannot reasonably be expected to displace more than a fraction of existing uses of any one existing lipids resource use represented in the table, it would likely process soy-dominated feed blends that are roughly proportionate to the yields shown.[46] This could result in a significant climate impact from the soybean oil-driven increase in hydrogen steam reforming emissions discussed in § 1.2.2.

Another example: Feedstock demand from the Contra Costa County HEFA projects alone represents one-third of current total U.S. yield for all uses of the lipids shown in Table 1, including food and food exports. Much smaller increases in biofuel feedstock demand for food crops spurred commodity price pressures that expanded crop and grazing lands into pristine areas globally, resulting in deforestation and damage to natural carbon sinks.[47] The unprecedented cumulative scale of potential new biofuel feedstock acquisition thus warrants evaluation of the potential for the project to contribute to cumulative indirect land use impacts at this new scale.

The DEIR, however, does not attempt either impact evaluation suggested in these examples. Its project description did not provide a sufficient basis for evaluating feedstock acquisition impacts that are directly related to the scale of the project, which the DEIR did not disclose or describe.

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[46] Data in Table 1 thus rebut the unsupported DEIR assertion that future project feeds are wholly speculative.
[47] See Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).

1.5 **Project Operational Duration**

The anticipated and technically achievable operational duration of the project, hence the period over which potential impacts of project operation could occur, accumulate, or worsen, is not disclosed or described in the DEIR. This is a significant deficiency because accurate estimation of impacts that worsen over time requires an accurately defined period of impact review.

Contra Costa County could have accessed many data on the operational duration of the project. The refiner would have designed and financed the project based on a specified operational duration. Since this is necessary data for environmental review it could have and should have been requested and supplied. Technically achievable operational duration data for the types of process units the project proposes to use were publicly available as well. For example, process unit-specific operational data for Bay Area refineries, including the subject refinery, have been compiled, analyzed and reported by Communities for a Better Environment.[48] Information to estimate the anticipated operational duration of the project also can be gleaned from technical data supporting pathways to achieve state climate protection goals,[49] which include phasing out petroleum and biofuel diesel in favor of zero-emission vehicles.

1.6 **Project Fuels Market**

The DEIR asserts an incomplete and inaccurate description of project fuels markets. It describes potential impacts that could result from conditions which it asserts will increase fuel imports into California[50] while omitting any discussion whatsoever of exports from California refineries or the conditions under which these exports could occur. California refineries are net fuel exporters due in large part to structural conditions of statewide overcapacity coupled with declining in-state petroleum fuels demand.[51] [52] [53] The incomplete description of the project fuels market setting led to flawed environmental impacts evaluation, as discussed in sections 2 and 5 herein.

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[48] Karras, 2020. *Decommissioning California Refineries: Climate and Health Paths in an Oil State;* A Report for Communities for a Better Environment. Prepared by Greg Karras. Includes Supporting Material Appendix. www.energy-re-source.com/decomm Appended hereto as Attachment 10.
[49] Karras, 2021a (Att. 2).
[50] DEIR pp. 5-3 though 5-7, 5-9, 5-10, 5-19, 5-22 through 5-24.
[51] Karras, 2020 (Att. 10).
[52] USEIA, 2015. West Coast Transportation Fuels Markets; U.S. Energy Information Administration: Washington, D.C. https://www.eia.gov/analysis/transportationfuels/padd5/ Appended hereto as Attachment 11.
[53] USEIA, *Supply and Disposition: West Coast (PADD 5);* U.S. Energy Information Administration: Washington, D.C. ww.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm. Appended hereto as Attachment 12.

1.7 **Project Scope**

The DEIR does not disclose or describe three components of the proposed project that would expand the project scope and its environmental impacts. One of these components directly expands project biofuel refining capacity. Another expands project biofuel refining feedstock input capacity. The third undisclosed component would debottleneck the project biofuel refining capacity by repurposing additional refinery equipment to produce additional hydrogen needed for the expanded biorefining from processing imported petroleum gasoline feedstocks.

1.7.1 The Unit 250 diesel hydrotreater biofuel processing component

During 2021 Phillips 66 implemented the conversion of diesel hydrotreater Unit 250 within the Rodeo facility from petroleum distillate to soybean oil processing[54] without a Clean Air Act permit[55] and without any public review. The DEIR asserts there is no connection between Unit 250 and the project because, it says, no further changes are proposed to the unit.[56] But whether or not *further* change to Unit 250 is proposed is not relevant to the question of whether the *previous* changes to that unit, completed after the project application was filed, should have been considered as part of the project.

The relevant question is whether the changes to Unit 250 are, *functionally*, part of the project, and they are. The project would depend on Unit 250 to maximize onsite refining of the feed pretreatment unit output; and in turn, Unit 250 would depend on the project. It would depend on project feed pretreatment for economical access to pretreated feed, as the DEIR itself concludes in considering project biorefining without that project component.[57] Even more clearly, since the deoxygenated output of HEFA hydrotreating is too waxy to meet fuel specifications and must be isomerized in a separate processing step before it can be sold as transportation fuel,[58] Unit 250 depends on the project isomerization component to make its output sellable. The Unit 250

[54] Phillips 66 1Q 2021 Earnings Transcript. First Quarter 2021 Earnings Call; Phillips 66 (NYSE: PSX) 30 April 2021, 12 p.m. ET. Transcript. Appended hereto as Attachment 13.
[55] BAAQMD, 2021. 9 Sep 2021 email from Damian Breen, Senior Deputy Executive Officer – Operations, Bay Area Air Quality Management District, to Ann Alexander, NRDC, regarding Phillips 66 refinery (no. 21359) – possible unpermitted modifications. Appended hereto as Attachment 14.
[56] DEIR p. 5-11.
[57] DEIR p. 5-6 (alternative without a feed pretreatment unit "considered to be infeasible because it would reduce transportation fuels production at the Rodeo Refinery and severely underuse existing refinery facilities for the production of renewable fuels").
[58] *See* subsection1.2.1 above; for more detail *see* Karras, 2021a (Att. 2).

HEFA conversion is an interdependent component of the project that is essential to achieve a project objective to maximize project-supplied California biofuels.

The conversion of Unit 250 from petroleum to HEFA feedstock processing is currently under investigation by the Bay Area Air Quality Management District (BAAQMD) for potentially illegal construction, operation, or both without required notice, review, and/or permits.[59]

The failure to include and disclose the Unit 250 HEFA conversion as part of the project appears to be related to a County decision to permit the Nustar biofuel action separately from the subject project before allowing public comment on either action, as discussed below.

1.7.2 <u>The Nustar Shore Terminals biofuel feedstock import conversion</u>

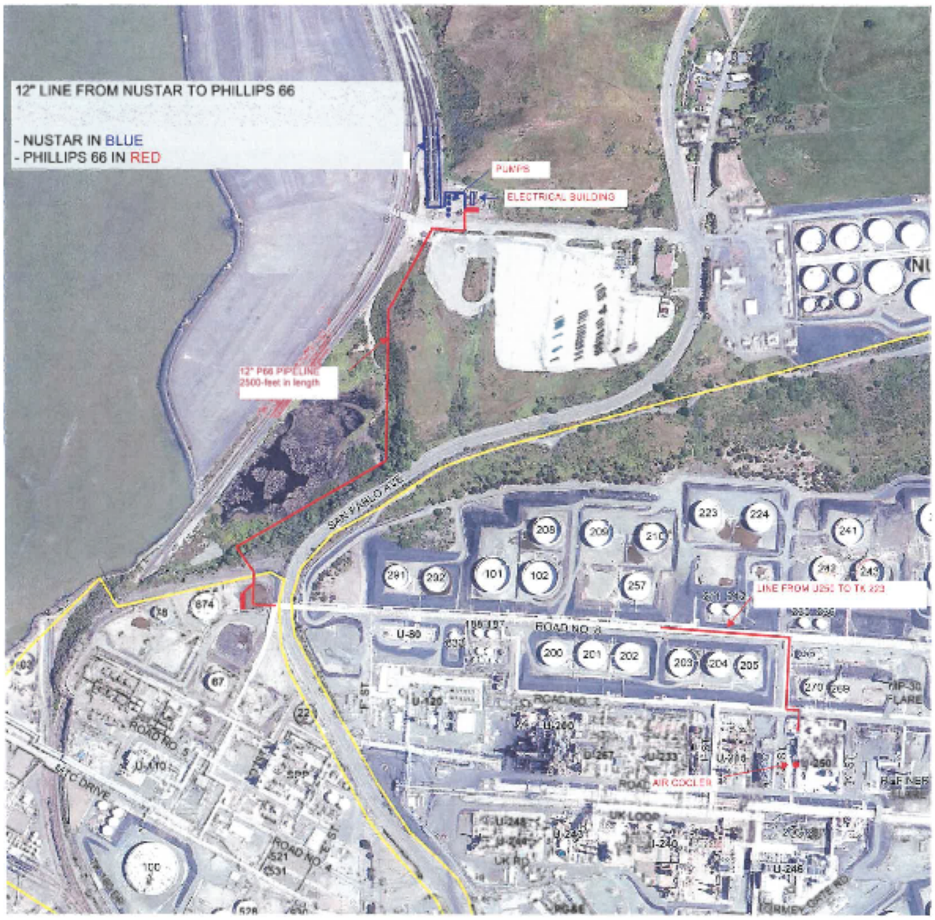
Nustar Shore Terminals—a liquid hydrocarbons transfer and storage facility contiguous with the Phillips 66 facility—and Contra Costa County have taken actions to advance the "Nustar Soybean Oil Project" contemporaneously with the project. According to a 2 December 2020 email from the County, this Nustar action would:

> [I]nstall an approximately 2300-foot pipeline from Nustar to Phillips 66 to carry pretreated soybean oil feedstock to existing tankage and the Unit 250 hydrotreater at the Phillips 66 refinery, which can already produce diesel from both renewable and crude feedstocks (see attached site plan). The soybean feedstock will be unloaded at existing Nustar rail facilities which will be modified with 33 offload headers to accommodate the soybean oil. ... it was determined that the modifications proposed by Nustar would not require a land use permit. The appropriate building permits have been issued. [60]

The site plan referenced by the County[61] is reproduced in its entirety below. Color-coding of the pipeline sections shown on the site plan indicates that the new feedstock pipeline sections reach far into the Phillips 66 refinery; and that the vast majority of new pipeline segments by length is "Phillips 66" rather than "Nustar" pipe.[62]

Interestingly as well, a closer look at the site map reveals the converted Unit 250 HEFA hydro-conversion processing plant at the terminus of the "Nustar Soybean Oil Project" in the refinery.

[59] BAAQMD, 2021 (Att. 14).
[60] Kupp, 2020a. Email text and attached site map from Gary Kupp, Contra Costa County, to Charles Davidson, incoming Rodeo-Hercules Fire Protection District director. 2 December 2020. Appended hereto as Attachment 15.
[61] *Id.*
[62] *Id.*



"Nustar Soybean Oil Project" Site Plan, Contra Costa County (Att. 15),

Accordingly, the available data and information would appear to provide sufficient basis to conclude that the Nustar Shore Terminals project is a component of the project. The DEIR, however, did not disclose or describe the relationship of these concurrently proposed actions at all, and consequently did not take account of potential impacts from a larger project scope.

1.7.3 <u>The component to debottleneck hydrogen-limited refining capacity</u>

Phillips 66 added a project component after the public scoping process that is not disclosed in the DEIR. This component would relieve a bottleneck in hydrogen-limited biofuel refining at the refinery by repurposing additional existing equipment to co-produce hydrogen as a byproduct of processing gasoline feedstocks derived from semi-refined petroleum imported to Rodeo. The DEIR identifies the physical changes integrated into the project post-scoping, but it does not identify their debottlenecking effect, and hence does not disclose or describe the additional onsite processing of additional petroleum and biomass or evaluate resultant impacts.

As discussed in sections 1.1 through 1.4, the DEIR does not describe and hence does not evaluate HEFA process demand for hydrogen. It thus failed to identify a hydrogen bottleneck in the disclosed project configuration which, if relieved, would enable processing the additional pretreated feedstock the revised project would produce. The County could have identified this bottleneck by comparing available hydrogen production capacity and process hydrogen demand data for the disclosed project components.[63] Had it done so it would have found that the repurposed hydrogen plants cannot actually supply enough hydrogen to refine 80,000 b/d of pretreated vegetable oils; and that this hydrogen bottleneck is particularly severe for jet fuel production. Targeting HEFA jet fuel, a more hydrogen-intensive refining mode,[64] the hydrogen bottleneck could limit project refining to only about 60% to 70% of pretreated feed capacity.[65]

The debottlenecking traces back to changes Phillips 66 made with respect to permit retention. The company changed its original project description so as to retain permits for existing refinery coking and naphtha reforming units, so that those units could continue or resume operation as part of the project.[66] Refinery crude distillation units would be shuttered upon full project implementation,[67] and the coking and reforming units would not process HEFA feedstock or whole crude. Instead, repurposing the coking and reforming units would involve processing semi-refined petroleum acquired from other refineries.[68] Phillips 66 recently stated in other contexts that it is shifting the specialty coke production from its petroleum refining to produce graphite for batteries,[69] and planning to use the Rodeo coking unit for that purpose.[70] The coking would co-produce light oils its reformers would then convert to gasoline blend stocks.

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[63] Karras, 2021b (Att. 3).
[64] *Id.*
[65] Based on 80,000 b/d project pretreated feed capacity (DEIR); 148,500,000 SCF/d H_2 production capacity of Rodeo units 110 and 120 (Att. 2); H_2 demand targeting jet fuel yield on tallow, and soybean oil, of 2,632, and 2,954 SCF/b feed (Att. 3); and the calculations (targeting jet fuel yield from on soy oil feed, for example): 148,500,000 SCF/d ÷ 2,954 SCF/b = 50,270 b/d of soy oil processed, and 50,270 b/d ÷ 80,000 b/d = 0.628 (63%).
[66] BAAQMD Application, 2021. *Compare* also Phillips 66 initial Project Description; DEIR pp. 3-28, 3-29.
[67] DEIR pp. 3-28. 3-29.
[68] Only whole crude processing is specifically precluded by the project objectives asserted. *See* DEIR p. 3-22.
[69] Phillips 66 3Q 2021 Earnings Conference Call; 29 Oct 2021, 12 p.m. ET. Appended hereto as Attachment 16.
[70] Weinberg-Lynn, 2021. 23 July 2021 email from Nikolas Weinberg-Lynn, Manager, Renewable Energy Projects, Phillips 66, to Charles Davidson. Appended hereto as Attachment 17.

The debottlenecking element—an important impact of the retained permits that is not identified in the DEIR—is that the light oil reforming would co-produce hydrogen,[71] thereby alleviating the jet biofuel production bottleneck described above.

This undisclosed hydrogen debottleneck action and the disclosed project components would be interdependent components of the project. The hydrogen debottleneck component depends upon the repurposing coking and reforming units that the project would free from crude refining support service. The disclosed project components, in turn, depend on the undisclosed hydrogen debottleneck for the ability to use their full capacity to produce biofuels, and especially HEFA jet fuel. Indeed, without relieving the hydrogen bottleneck the project might not long be viable. The hydrogen debottleneck component would afford the ability to engage in more hydrogen-intensive jet fuel processing, which could boost jet biofuel yield on biomass feedstock from as little as 13% to as much as 49%.[72] That could allow shifting to jet biofuel production without more drastic cuts in total project biofuel production as State zero-emission vehicle policies phase out diesel biofuels along with petroleum diesel demand.

Thus, Phillips 66 would be highly incentivized to debottleneck its biorefinery; has asserted informal plans *and* formal project objectives[73] consistent with that result; and crucially, has changed its project to include the specific equipment which would be used to debottleneck the project in the project. Absent a binding commitment not to implement this action, it would be reasonable to conclude that it is a project component. The DEIR, however, did not disclose or describe this project component, and consequently did not evaluate its potential impacts.

CONCLUSION: The DEIR provides an incomplete, inaccurate, and truncated description of the proposed project. Available information that the DEIR does not describe or disclose will be necessary for sufficient review of environmental impacts that could result from the project.

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[71] *See* Chevron Refinery Modernization Project DEIR Appendix 4.3–URM: Unit Rate Model (Att. 5). *See* also Bredeson et al., 2010. Factors driving refinery CO_2 intensity, with allocation into products. *Int. J. Life Cycle Assess.* 15:817–826. DOI: 10.1007/s11367-010-0204-3. Appended hereto as Attachment 18; and Abella and Bergerson, 2012. Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration. *Environ. Sci. Technol.* 46: 13037–13047. dx.doi.org/10.1021/es3018682. Appended hereto as Attachment19.
[72] Karras, 2021b (Att. 3).
[73] DEIR p. 3-22 (objectives to maximize production of renewable fuels and reuse existing equipment).

2. THE DEIR DID NOT CONSIDER A SIGNIFICANT POTENTIAL CLIMATE EMISSION-SHIFTING IMPACT LIKELY TO RESULT FROM THE PROJECT

Instead of replacing fossil fuels, adding renewable diesel to the liquid combustion fuel chain in California resulted in refiners protecting their otherwise stranded assets by increasing exports of petroleum distillates burned elsewhere, causing a net increase in greenhouse gas[74] emissions. The DEIR improperly concludes that the project would decrease net GHG emissions[75] without disclosing this emission-shifting, or evaluating its potential to further increase net emissions. A series of errors and omissions in the DEIR further obscures causal factors for the emission shifting by which the project would cause and contribute to this significant potential impact.

2.1 The DEIR Does Not Disclose or Evaluate Available Data Which Contradict its Conclusion That the Project Would Result in a Net Decrease in GHG Emissions

State law warns against "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."[76] However, the DEIR does not evaluate this emission-shifting impact of the project. Relevant state data that the DEIR failed to disclose or evaluate include volumes of petroleum distillates refined in California[77] and total distillates—petroleum distillates and diesel biofuels—burned in California.[78] Had the DEIR evaluated these data the County could have found that its conclusion regarding net GHG emissions resulting from the project was unsupported.

As shown in Chart 2, distillate fuels refining for export continued to expand in California as biofuels that were expected to replace fossil fuels added a new source of carbon to the liquid combustion fuel chain. Total distillate volumes, including diesel biofuels burned in-state, petroleum distillates burned in-state, and petroleum distillates refined in-state and exported to other states and nations, increased from approximately 4.3 billion gallons per year to approximately 6.4 billion gallons per year between 2000 and 2019.[79] [80]

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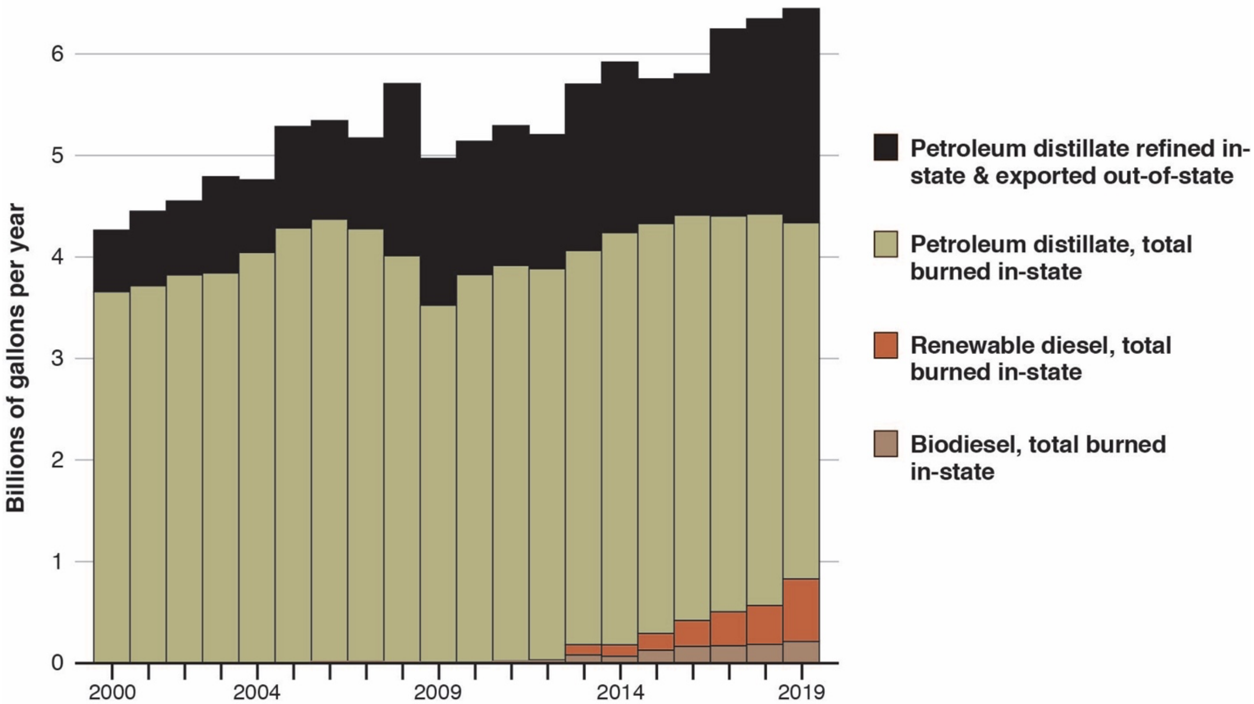
[74] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[75] "Project operations would decrease emissions of GHGs that could contribute to global climate change" (DEIR p. 2-5) including "indirect emissions" (DEIR p. 4.8-258) and "emissions from transportation fuels" (DEIR p. 4.8-266).
[76] CCR §§ 38505 (j), 38562 (b) (8).
[77] CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php Appended hereto as Attachment 20.
[78] CARB GHG Inventory. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity; 14th ed.: 2000 to 2019;* California Air Resources Board: Sacramento, CA. Appended hereto as Attachment 21.

[79] *Id.*
[80] CEC Fuel Watch (Att. 21).



Distillate fuel shares associated with all activities in California, 2000–2019.
Growth in total distillates excluding jet fuel and kerosene from State data.

CHART 2. Data from CEC Fuel Watch (Att. 20) and CARB GHG Inventory (Att. 21).

Petroleum distillates refining for export (black in the chart) expanded after in-state burning of petroleum distillate (olive) peaked in 2006, and the exports expanded again from 2012 to 2019 with more in-state use of diesel biofuels (dark red and brown). From 2000 to 2012 petroleum-related factors alone drove an increase in total distillates production and use associated with all activities in California of nearly one billion gallons per year. Then total distillates production and use associated with activities in California increased again, by more than a billion gallons per year from 2012 to 2019, with biofuels accounting for more than half that increment. These state data show that diesel biofuels did not replace petroleum distillates refined in California during the eight years before the project was proposed. Instead, producing and burning more renewable diesel *along with* the petroleum fuel it was supposed to replace emitted more carbon.

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2.2 The DEIR Presents an Incomplete and Misleading Description of the Project Market Setting that Focuses on Imports and Omits Structural Overcapacity-driven Exports, Thereby Obscuring a Key Causal Factor in the Emission-shifting Impact

The DEIR focuses on potential negative effects of reliance on imports if the proposed project is rejected in favor of alternatives,[81] while ignoring fuels exports from in-state refineries and conditions under which these exports occur. As a result the DEIR fails to disclose that crude refineries here are net fuels exporters, that their exports have grown as in-state and West Coast demand for petroleum fuels declined, and that the structural overcapacity resulting in this export emissions impact would not be resolved and could be worsened by the project.

Due to the concentration of petroleum refining infrastructure in California and on the U.S. West Coast, including California and Puget Sound, WA, these markets were net exporters of transportation fuels before renewable diesel flooded into the California market.[82] Importantly, before diesel biofuel addition further increased refining of petroleum distillates for export, the structural overcapacity of California refineries was evident from the increase in their exports after in-state demand peaked in 2006. <u>*See*</u> Chart 2 above. California refining capacity, especially, is overbuilt.[83] Industry reactions seeking to protect those otherwise stranded refining assets through increased refined fuels exports as domestic markets for petroleum fuels declined resulted in exporting fully 20% to 33% of statewide refinery production to other states and nations from 2013–2017.[84] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[85] <u>*See*</u> Table 2.

Table 2. West Coast (PADD 5) Finished Petroleum Products: Decadal Changes in Domestic Demand and Foreign Exports, 1990–2019.

Total volumes reported for ten-year periods

	Volume (billions of gallons)		Decadal Change (%)	
Period	Demand	Exports	Demand	Exports
1 Jan 1990 to 31 Dec 1999	406	44.2	—	—
1 Jan 2000 to 31 Dec 2009	457	35.1	+13 %	–21 %
1 Jan 2010 to 31 Dec 2019	442	50.9	–3.3 %	+45 %

Data from USEIA, *Supply and Disposition* (Att. 12).

[81] DEIR pp. 5-3 though 5-7, 5-9, 5-10, 5-19, 5-22 through 5-24.
[82] USEIA, 2015 (Att. 11).
[83] Karras, 2020 (Att. 10).
[84] *Id.*
[85] USEIA, *Supply and Disposition* (Att. 12).

Comparisons of historic with recent California and West Coast data further demonstrate that this crude refining overcapacity for domestic petroleum fuels demand that drives the emission-shifting impact is unresolved and would not be resolved by the proposed project and the related Contra Costa County crude-to-biofuel conversion project. Fuels demand has rebounded, at least temporarily, from pre-vaccine pandemic levels to the range defined by pre-pandemic levels, accounting for seasonal and interannual variability. In California, from April through June 2021 taxable fuel sales[86] approached the range of interannual variability from 2012–2019 for gasoline and reached the low end of this pre-COVID range in July, while taxable jet fuel and diesel sales exceeded the maximum or median of the 2012–2019 range in each month from April through July of 2021. <u>See</u> Table 3.

Table 3. California Taxable Fuel Sales Data: Return to Pre-COVID Volumes

Fuel volumes in millions of gallons (MM gal.) per month

	Demand	Pre-COVID range (2012–2019)			Comparison of 2021 data with
	in 2021	Minimum	Median	Maximum	the same month in 2012–2019
Gasoline (MM gal.)					
Jan	995	1,166	1,219	1,234	Below pre-COVID range
Feb	975	1,098	1,152	1,224	Below pre-COVID range
Mar	1,138	1,237	1,289	1,343	Below pre-COVID range
Apr	1,155	1,184	1,265	1,346	Approaches pre-COVID range
May	1,207	1,259	1,287	1,355	Approaches pre-COVID range
Jun	1,196	1,217	1,272	1,317	Approaches pre-COVID range
Jul	1,231	1,230	1,298	1,514	Within pre-COVID range
Jet fuel (MM gal.)					
Jan	10.74	9.91	11.09	13.69	Within pre-COVID range
Feb	10.80	10.13	11.10	13.58	Within pre-COVID range
Mar	13.21	11.23	11.95	14.53	Exceeds pre-COVID median
Apr	13.84	10.69	11.50	13.58	Exceeds pre-COVID range
May	15.14	4.84	13.07	16.44	Exceeds pre-COVID median
Jun	17.08	8.67	12.75	16.80	Exceeds pre-COVID range
Jul	16.66	11.05	13.34	15.58	Exceeds pre-COVID range
Diesel (MM gal.)					
Jan	203.5	181.0	205.7	217.8	Within pre-COVID range
Feb	204.4	184.1	191.9	212.7	Exceeds pre-COVID median
Mar	305.4	231.2	265.2	300.9	Exceeds pre-COVID range
Apr	257.1	197.6	224.0	259.3	Exceeds pre-COVID median
May	244.5	216.9	231.8	253.0	Exceeds pre-COVID median
Jun	318.3	250.0	265.0	309.0	Exceeds pre-COVID range
Jul	248.6	217.8	241.5	297.0	Exceeds pre-COVID median

Data from CDTFA, (Att. 22). Pre-COVID statistics are for the same months in 2012–2019. The multiyear monthly comparison range accounts for seasonal and interannual variability in fuels demand. Jet fuel totals may exclude fueling in California for fuels presumed to be burned outside the state during interstate and international flights.

[86] CDTFA, various years. *Fuel Taxes Statistics & Reports;* Cal. Dept. Tax and Fee Admin: Sacramento, CA. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm. Appended hereto as Attachment 22.

West Coast fuels demand in April and May 2021 approached or fell within the 2010–2019 range for gasoline and jet fuel and exceeded that range for diesel.[87] In June and July 2021 demand for gasoline exceeded the 2010–2019 median, jet fuel fell within the 2010–2019 range, and diesel fell within the 2010–2019 range or exceeded the 2010–2019 median.[88] <u>See</u> Table 4.

Table 4. West Coast (PADD 5) Fuels Demand Data: Return to Pre-COVID Volumes

Fuel volumes in millions of barrels (MM bbl.) per month

	Demand in 2021	Pre-COVID range (2010–2019) Minimum	Median	Maximum	Comparison of 2021 data with the same month in 2010–2019
Gasoline (MM bbl.)					
Jan	38.59	42.31	45.29	49.73	Below pre-COVID range
Feb	38.54	40.94	42.75	47.01	Below pre-COVID range
Mar	45.14	45.23	48.97	52.53	Approaches pre-COVID range
Apr	44.97	44.99	47.25	50.20	Approaches pre-COVID range
May	48.78	46.79	49.00	52.18	Within pre-COVID range
Jun	48.70	45.61	48.14	51.15	Exceeds pre-COVID median
Jul	50.12	47.33	49.09	52.39	Exceeds pre-COVID median
Jet fuel (MM bbl.)					
Jan	9.97	11.57	13.03	19.07	Below pre-COVID range
Feb	10.35	10.90	11.70	18.33	Below pre-COVID range
Mar	11.08	11.82	13.68	16.68	Below pre-COVID median
Apr	11.71	10.83	13.78	16.57	Within pre-COVID range
May	12.12	12.80	13.92	16.90	Approaches pre-COVID range
Jun	14.47	13.03	14.99	17.64	Within pre-COVID range
Jul	15.31	13.62	15.46	18.41	Within pre-COVID range
Diesel (MM bbl.)					
Jan	15.14	12.78	14.41	15.12	Exceeds pre-COVID range
Feb	15.01	12.49	13.51	15.29	Exceeds pre-COVID median
Mar	17.08	14.12	15.25	16.33	Exceeds pre-COVID range
Apr	15.76	14.14	14.93	16.12	Exceeds pre-COVID median
May	16.94	15.11	15.91	17.27	Exceeds pre-COVID median
Jun	14.65	14.53	16.03	16.84	Within pre-COVID range
Jul	16.94	15.44	16.40	17.78	Exceeds pre-COVID median

Data from USEIA *Supply and Disposition* (Att. 12). "Product Supplied," which approximately represents demand because it measures the disappearance of these fuels from primary sources, i.e., refineries, gas processing plants, blending plants, pipelines, and bulk terminals. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID statistics are for the same month in 2010–2019, thus accounting for seasonal and interannual variability.

Despite this several-month surge in demand the year after the Marathon Martinez refinery closed, California and West Coast refineries supplied the rebound in fuels demand while running well below capacity. Four-week average California refinery capacity utilization rates from 20 March through 6 August 2021 ranged from 81.6% to 87.3% (Table 5), similar to those across the

[87] USEIA, *Supply and Disposition* (Att. 12).
[88] *Id.*

Table 5. Total California Refinery Capacity Utilization in Four-week Periods of 2021.

barrel (oil): 42 U.S. gallons **barrels/calendar day:** see table caption below

Four-week period	Calif. refinery crude input (barrels/day)	Operable crude capacity (barrels/calendar day)	Capacity utilized (%)
12/26/20 through 01/22/21	1,222,679	1,748,171	69.9 %
01/23/21 through 02/19/21	1,199,571	1,748,171	68.6 %
02/20/21 through 03/19/21	1,318,357	1,748,171	75.4 %
03/20/21 through 04/16/21	1,426,000	1,748,171	81.6 %
04/17/21 through 05/14/21	1,487,536	1,748,171	85.1 %
05/15/21 through 06/11/21	1,491,000	1,748,171	85.3 %
06/12/21 through 07/09/21	1,525,750	1,748,171	87.3 %
07/10/21 through 08/06/21	1,442,750	1,748,171	82.5 %
08/07/21 through 09/03/21	1,475,179	1,748,171	84.4 %
09/04/21 through 10/01/21	1,488,571	1,748,171	85.1 %
10/02/21 through 10/29/21	1,442,429	1,748,171	82.5 %

Total California refinery crude inputs from Att. 20. Statewide refinery capacity as of 1/1/21, after the Marathon Martinez refinery closure, from Att. 23. Capacity in barrels/calendar day accounts for down-stream refinery bottlenecks, types and grades of crude processed, operating permit constraints, and both scheduled and unscheduled downtime for inspection, maintenance, and repairs.

West Coast, and well below maximum West Coast capacity utilization rates for the same months in 2010–2019 (Table 6).[89] [90] [91] Moreover, review of Table 5 reveals 222,000 b/d to more than 305,000 b/d of spare California refinery capacity during this fuels demand rebound.

Table 6. West Coast (PADD 5) Percent Utilization of Operable Refinery Capacity.

Month	Capacity Utilized **in 2021**	Pre-COVID range for same month in 2010–2019: Minimum	Median	Maximum
January	73.3 %	76.4 %	83.7 %	90.1 %
February	74.2 %	78.2 %	82.6 %	90.9 %
March	81.2 %	76.9 %	84.8 %	95.7 %
April	82.6 %	77.5 %	82.7 %	91.3 %
May	84.2 %	76.1 %	84.0 %	87.5 %
June	88.3 %	84.3 %	87.2 %	98.4 %
July	85.9 %	83.3 %	90.7 %	97.2 %
August	87.8 %	79.6 %	90.2 %	98.3 %
September	—	80.4 %	87.2 %	96.9 %
October	—	76.4 %	86.1 %	91.2 %
November	—	77.6 %	85.3 %	94.3 %
December	—	79.5 %	87.5 %	94.4 %

Utilization of operable capacity in barrels/calendar day from Att. 24. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID data for the same month in 2010–2019 accounts for seasonal and interannual variability.

[89] CEC Fuel Watch (Att. 20).
[90] USEIA *Refinery Capacity by Individual Refinery*. Data as of Jan 1, 2021; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity Appended hereto as Attachment 23.
[91] USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Information Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm Appended hereto as Attachment 24.

Spare California refining capacity during this period when fuels demand increased to reach pre-COVID levels and crude processing at the Marathon Martinez refinery was shut down (222,000 to 305,000 b/cd) exceeded the total 120,200 b/cd crude capacity of the Phillips 66 refinery.[92] Thus, the project could not fully alleviate the growing condition of overcapacity that drives refined fuels export emission-shifting; rather, it would produce and sell an unprecedented amount of California-targeted HEFA diesel into the California fuels market.

Accordingly, the project can be expected to worsen in-state petroleum refining overcapacity, and hence the emission shift, by adding a very large volume of HEFA diesel to the California liquid combustion fuels mix. Indeed, maximizing additional "renewable" fuels production for the California market is a project objective.[93] The DEIR, however, does not disclose or evaluate this causal factor for the observed emission-shifting impact of recent "renewable" diesel additions.

2.3 The DEIR Does Not Describe or Evaluate Project Design Specifications That Could Cause and Contribute to Significant Emission-shifting Impacts

Having failed to describe the unique capabilities and limitations of the proposed biofuel technology (§§ 1.1.1, 1.1.2), the DEIR does not evaluate how fully integrating renewable diesel into petroleum fuels refining, distribution, and combustion infrastructure could worsen emission shifting by more directly tethering biofuel addition here to petroleum fuel refining for export. Compounding its error, the DEIR does not evaluate the impact of another basic project design specification—project fuels production capacity. The DEIR does not estimate how much HEFA diesel the project could add to the existing statewide distillates production oversupply, or how much that could worsen the emission shifting impact. Had it done so, using readily available state default factors for the carbon intensities of these fuels, the County could have found that the project would likely cause and contribute to significant climate impacts. <u>*See*</u> Table 7 below.

Accounting for yields on feeds targeting renewable diesel[94] and typical feed and fuel densities shown in Table 7, operating below capacity at 55,000 b/d the project could make approximately 1.86 million gallons per day of renewable diesel, resulting in export of the equivalent petroleum

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[92] Though USEIA labels the San Francisco Refinery site as Rodeo, both the Rodeo Facility and the Santa Maria Facility capacities are included in the 120,200 barrels/calendar day (b/cd) cited: USEIA *Refinery Capacity by Individual Refinery* (Att. 23).
[93] DEIR p. 3-22.
[94] Pearlson et al., 2013. A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production. *Biofuels, Bioprod. Bioref.* 7: 89–96. DOI: 10.1002/bbb.1378. Appended hereto as Attachment 25.

distillates volume. State default factors for full fuel chain "life cycle" emissions associated with the type of renewable diesel proposed account for a range of potential emissions, from lower emission ("residue") to higher emission ("crop biomass") feeds, which is shown in the table.[95] The net emission shifting impact of the project based on this range of factors could thus be approximately 3.96 to 5.72 *million* metric tons (Mt) of CO_2e emitted per year. Table 7. Those potential project emissions would exceed the 10,000 metric tons per year (0.01 Mt/year) significance threshold in the DEIR by 395 to 571 times.

A *conservative* estimate of net cumulative emissions from this impact of the currently proposed biofuel refinery projects in the County, *if* state goals to replace all diesel fuels are achieved more quickly than anticipated, is in the range of approximately 74 Mt to 107 Mt over ten years. *Id.*

Table 7. Potential GHG Emission Impacts from Project-induced Emission Shifting: Estimates Based on Low Carbon Fuel Standard Default Emission Factors.

RD: renewable diesel **PD:** petroleum distillate **CO_2e:** carbon dioxide equivalents **Mt:** million metric tons

Estimate Scope	Phillips 66 Project	Marathon Project	Both Projects
Fuel Shift (millions of gallons per day) [a]			
RD for in-state use	1.860	1.623	3.482
PD equivalent exported	1.860	1.623	3.482
Emission factor (kg CO_2e/galllon) [b]			
RD from residue biomass feedstock	5.834	5.834	5.834
RD from crop biomass feedstock	8.427	8.427	8.427
PD (petroleum distillate [ULSD factor])	13.508	13.508	13.508
Fuel-specific emissions (Mt/year) [c]			
RD from residue biomass feedstock	3.96	3.46	7.42
RD from crop biomass feedstock	5.72	4.99	10.7
PD (petroleum distillate)	9.17	8.00	17.2
Net emission shift impact [d]			
Annual minimum (Mt/year)	3.96	3.46	7.42
Annual maximum (Mt/year)	5.72	4.99	10.7
Ten-year minimum (Mt)	39.6	34.6	74.2
Ten-year maximum (Mt)	57.2	49.9	107

a. Calculated based on DEIR project feedstock processing capacities,* yield reported for refining targeting HEFA diesel by Pearlson et al., 2013, and feed and fuel specific gravities of 0.916 and 0.775 respectively. **b.** CARB default emission factors from tables 2, 4, 7-1, 8 and 9, Low Carbon Fuel Standard Regulation, CCR §§ 95484–95488. **c.** Fuel-specific emissions are the products of the fuel volumes and emission factors shown. **d.** The emission shift impact is the net emissions calculated as the sum of the fuel-specific emissions minus the incremental emission from the petroleum fuel *v.* the same volume of the biofuel. Net emissions are thus equivalent to emissions from the production and use of renewable diesel that *does not* replace petroleum distillates, as shown. Annual values compare with the DEIR significance threshold (0.01 Mt/year); ten-year values provide a conservative estimate of cumulative impact assuming expeditious implementation of State goals to replace all diesel fuels.
* Phillips 66 Project data calculated at 55,000 b/d feed rate, less than its proposed 80,000 b/d project feed capacity.

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[95] Low Carbon Fuel Standard Regulation, tables 2, 4, 7-1, 8 and 9. CCR §§ 95484–95488.

2.4 The DEIR Does Not Consider Air Quality or Environmental Justice Impacts From GHG Co-Pollutants that Could Result from Project Emission Shifting

Having neglected to consider emission shifting that could result from the project, the DEIR does not evaluate air quality or environmental justice impacts that could result from GHG co-emissions. Had it considered the emission-shifting impact the County could have evaluated substantial relevant information regarding potential impacts of GHG co-pollutants.

Among other relevant available information: Pastor and colleagues found GHG co-pollutants emissions of particulate matter from large industrial GHG emitters in general, and refineries in particular, result in substantially increased emission burdens in low-income communities of color throughout the state.[96] Clark and colleagues found persistent disparately elevated exposures to refined fuels combustion emissions among people of color along major roadways in California and the U.S.[97] Zhao and colleagues showed that exposures to the portion of those emissions that could result from climate protection decisions to use more biofuel, instead of more electrification of transportation among other sectors, would cause very large air pollution-induced premature death increments statewide.[98]

Again, however, the DEIR did not evaluate these potential project emission-shifting impacts.

CONCLUSION: A reasonable potential exists for the project to result in significant climate and air quality impacts by increasing the production and export of California-refined fuels instead of replacing petroleum fuels. This impact would be related to the particular type and use of biofuel proposed. Resultant greenhouse gases and co-pollutants would emit in California from excess petroleum and biofuel refining, and emit in California as well as in other states and nations from petroleum and biofuel feedstock extraction and end-use fuel combustion. The DEIR does not identify, evaluate, or mitigate these significant potential impacts of the project.

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[96] Pastor et al., 2010. *Minding the Climate Gap: What's at stake if California's climate law isn't done right and right away;* College of Natural Resources, Department of Environmental Science, Policy, and Management, University of California, Berkeley: Berkeley, CA; and Program for Environmental and Regional Equity, University of Southern California: Los Angeles, CA. Appended hereto as Attachment 26.

[97] Clark et al, 2017. Changes in transportation-related air pollution exposures by race-ethnicity and socioeconomic status: Outdoor nitrogen dioxide in the United States in 2000 and 2010. *Environmental Health Perspectives* 097012-1 to 097012-10. 10.1289/EHP959. Appended hereto as Attachment 27.

[98] Zhao et al., 2019. Air quality and health co-benefits of different deep decarbonization pathways in California. *Environ. Sci. Technol.* 53: 7163–7171. DOI: 10.1021/acs.est.9b02385. Appended hereto as Attachment 28.

3. THE DEIR DOES NOT PROVIDE A COMPLETE OR ACCURATE ANALYSIS OF PROCESS HAZARDS AND DOES NOT IDENTIFY, EVALUATE, OR MITIGATE SIGNIFICANT POTENTIAL PROJECT HAZARD IMPACTS

Oil refining is an exceptionally high-hazard industry in which switching to a new and different type of oil feed has known potential to introduce new hazards, intensify existing hazards, or both. Switching from crude petroleum to HEFA feedstock refining introduces specific new hazards that could increase the incidence rate of refinery explosions and uncontrolled fires, hence the likelihood of potentially catastrophic consequences of the project over its operational duration. The DEIR does not identify, evaluate, or mitigate these specific process hazards or significant potential process hazard impacts. A series of errors and omissions in the DEIR further obscures these process hazards and impacts.

3.1 The DEIR Does Not Provide a Complete or Accurate Analysis of Project Hazards

The DEIR states that its process hazard analysis "approach involves examining the potential hazards produced by the inventory of hazardous materials and comparing the baseline with the Project level of hazardous materials use and storage."[99] This comparison is further limited to "how readily the material produces a vapor cloud and how readily the material will ignite and burn,"[100] and to comparing only raw feedstocks or finished refined products.[101] The DEIR then concludes that project feedstocks present substantially lower hazards, "do not end up producing as much lighter-ends at the refinery for storage and processing ... [and] in general, the Project would present less hazards to the public and the impacts would be less than significant."[102]

However, this DEIR analysis is incomplete and inaccurate in ways that obscure rather than identify potential process hazard impacts. In the first instance, its comparison of raw feeds and finished products omits consideration of explosive and flammable mixtures of semi-processed hydrocarbons and hydrogen at high temperature and extreme pressure in project hydro-conversion reactors.[103] This alone shows the DEIR conclusion regarding project process hazards to be unsupported. Yet it is but one omission from the DEIR hazards analysis. The DEIR does

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[99] DEIR p. 4.9-321.
[100] DEIR p. 4.9-336.
[101] DEIR p. 4.9-337, Table 4.9-5 (hydrogen; methane; propane; gasoline; jet fuel; diesel fuel; un-weathered light, medium, and heavy crude oil; crude bitumen; cooking oil; and Grade 1 Tallow).
[102] DEIR p. 338.
[103] *See* subsections 1.2 and 1.3 herein above.

not include, and does not report substantively on results from, any of several standard process hazard analysis requirements applicable to petroleum crude refining.

The DEIR did not include or report substantive results of any Process Hazard Analysis (PHA);[104] Hierarchy of Hazard Controls Analysis; Inherent Safety Measure analysis; recommendations to prioritize inherent safety measures and then include safeguards as added layers of protection from any potential project process hazard, or Management of Change (MOC) to manage potential hazards of process change[105] during the proposed feedstock switch.

Although the DEIR mentions some of these standard refinery process safety requirements and safeguards, its description of them is incomplete. PHA, Hierarchy of Hazard Controls Analysis, and Inherent Safety Measure, Safeguard, and Layer of Protection analyses are a sequence of rigorous formal analyses. Together they are designed to identify and evaluate specific hazards in specific processes and processing systems, ensure that the most effective types of measures which can eliminate each identified hazard are prioritized, then add safeguards, in declining order of effectiveness, to reduce any remaining hazard.[106]

PHAs seek to identify and evaluate the potential severity of specific hazards in specific project processes or processing systems.[107] These are the types of hazards the DEIR analysis method cannot identify, as discussed above. Hierarchy of Hazard Controls Analysis then seeks to ensure Inherent Safety Measures, designed to eliminate specific hazards and thus the most effective type of process hazard mitigation, are prioritized to the maximum extent feasible.[108] In contrast, the DEIR analysis fails to identify process hazards evidenced by proposed project use of "safety" flaring,[109] evaluate the significance of hazardous releases from flaring, or analyze mitigation measures which may be necessary in addition to the flaring safeguard and could reduce flaring.

The DEIR could have used an appropriate and established standard method to identify, evaluate, and analyze ways to lessen or avoid process hazards that could result from the project. Had it done so significant process hazards could have been identified, as discussed below.

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[104] A PHA is a hazard evaluation to identify, evaluate, and control the hazards involved in a process.
[105] See California refinery process safety management regulation, CCR § 5189.
[106] *Id.*
[107] *Id.*
[108] *Id.*
[109] DEIR p. 3-17.

3.2 The DEIR Does Not Identify or Evaluate Significant Process Hazard Impacts, Including Refinery Explosions and Fires, That Could Result from the Project

Had the DEIR provided a complete and accurate process hazard evaluation the County could have identified significant impacts that would result from project process hazards.[110]

3.2.1 <u>The DEIR does not disclose or evaluate available information which reveals that the project could increase refinery explosion and fire risks compared with crude refining</u>

After a catastrophic pipe failure ignited in the Richmond refinery sending 15,000 people to hospital emergency rooms, a feed change was found to be a causal factor in that disaster—and failures by Chevron and public safety officials to take hazards of that feed change seriously were found to be its root causes. The oil industry knew that introducing a new and different crude into an existing refinery can introduce new hazards. More than this, as it has long known, side effects of feed processing can cause hazardous conditions in the same types of hydro-conversion units now proposed to be repurposed for HEFA biomass feeds, and feedstock changes are among the most frequent causes of dangerous upsets in these hydro-conversion reactors.[111]

Differences between the new biomass feedstock proposed and crude oil are more extreme than those among crudes which Chevron ignored the hazards of before the August 2012 disaster in Richmond, and involve oxygen in the feed, rather than sulfur as in that disaster. This categorical difference between oxygen and sulfur, rather than a degree of difference in feed sulfur content, risks further minimizing the accuracy, or even feasibility, of predictions based on historical data. At 10.8–11.5 wt. %, HEFA feeds have very high oxygen content, while the petroleum crude fed to refinery processing has virtually none.[112] Carbonic acid forms from that oxygen in HEFA processing.[113] Carbonic acid corrosion is a known hazard in HEFA processing.[114] But this corrosion mechanism, and the specific locations it attacks in the refinery, differ from those of the sulfidic corrosion involved in the 2012 Richmond incident. Six decades of industry experience with sulfidic corrosion cannot reliably guide—and could misguide—the refiner as it attempts to find, then fix, damage from this new hazard before it causes equipment failures.[115]

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[110] My recent work has included in-depth review and analysis of process hazards associated with crude-to-biofuel refinery conversions; summaries of this work are excerpted from Karras, 2021a (Att. 2) in §§ 3.2.1–3.2.5 herein.
[111] Karras, 2021a (Att. 2).
[112] *Id.*
[113] Chan, 2020. *Converting a Petroleum Diesel Refinery for Renewable Diesel;* White Paper / Renewable Diesel. Burns McDonnell. www.burnsmcd.com. Appended hereto as Attachment 29.
[114] *Id.*
[115] Karras, 2021a (Att. 2).

Worse, high-oxygen HEFA feedstock can boost hydrogen consumption in hydro-conversion reactors dramatically. That creates more heat in reactors already prone to overheating in petroleum refining. Switching repurposed hydrocrackers and hydrotreaters to HEFA feeds would introduce this second new oxygen-related hazard.[116]

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.[117] [118] [119] When they consume more hydrogen, they generate more heat.[120] Then they get hotter, and crack more of their feed, consuming even more hydrogen,[121] [122] so "the hotter they get, the faster they get hot."[123] And the reactions proceed at extreme pressures of 600–2,800 pound-force per square inch,[124] so the exponential temperature rise can happen fast.

Refiners call these runaway reactions, temperature runaways, or "runaways" for short. Hydro-conversion runaways are remarkably dangerous. They have melted holes in eight-inch-thick, stainless steel, walls of hydrocracker reactors,[125] and worse. Consuming more hydrogen per barrel in the reactors, and thereby increasing reaction temperatures, HEFA feedstock processing can be expected to increase the frequency and magnitude of runaways.[126]

High temperature hydrogen attack or embrittlement of metals in refining equipment with the addition of so much more hydrogen to HEFA processing is a third known hazard.[127] And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.[128]

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[116] *Id.*
[117] Robinson and Dolbear, 2007. Commercial Hydrotreating and Hydrocracking. *In:* Hydroprocessing of heavy oils and residua. Ancheyta, J., and Speight, J., eds. CRC Press, Taylor & Francis Group: Boca Raton, FL. ISBN-13: 978-0-8493-7419-7. Appended hereto as Attachment 30.
[118] van Dyk et al., 2019. Potential synergies of drop-in biofuel production with further co-processing at oil refineries. *Biofuels Bioproducts & Biorefining* 13: 760–775. DOI: 10.1002/bbb.1974. Appended hereto as Attachment 31.
[119] Chan, 2020 (Att. 29).
[120] van Dyk et al., 2019 (Att. 31).
[121] *Id.*
[122] Robinson and Dolbear, 2007 (Att. 30).
[123] *Id.*
[124] *Id.*
[125] *Id.*
[126] Karras, 2021a (Att 2).
[127] Chan, 2020 (Att. 29).
[128] Karras, 2021a (Att. 2).

On top of all this, interdependence across the process system—such as the critical need for real-time balance between hydro-conversion units that feed hydrogen and hydrogen production units that make it—magnifies these hazards. Upsets in one part of the system can escalate across the refinery. Hydrogen-related hazards that manifest at first as isolated incidents can escalate with catastrophic consequences.[129]

3.2.2 <u>The DEIR does not disclose or evaluate available information about potential consequences of hydrogen-related hazards that the project could worsen</u>

Significant and sometimes catastrophic incidents involving the types of hydrogen processing proposed by the project are unfortunately common in crude oil refining, as reflected in the following incident briefs posted by *Process Safety Integrity*[130] report:

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire.
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage.
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor.
- A 2015 hydrogen conduit explosion throws workers against a steel refinery structure.
- Fifteen workers die, and 180 others are injured, in a series of explosions when hydrocarbons flood a distillation tower during a 2005 isomerization unit restart.
- A vapor release from a valve bonnet failure in a high-pressure hydrocracker section ignites in a major 1999 explosion and fire at the Chevron Richmond refinery.
- A worker dies, 46 others are injured, and the community must shelter in place when a release of hydrogen and hydrocarbons under high temperature and pressure ignites in a 1997 hydrocracker explosion and fire at the Tosco (now Marathon) Martinez refinery.
- A Los Angeles refinery hydrogen processing unit pipe rupture releases hydrogen and hydrocarbons that ignite in a 1992 explosion and fires that burn for three days.
- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on other nearby Richmond refinery equipment.
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.

These incidents all occurred in the context of crude oil refining. For the reasons described in this section, there is cause for concern that the frequency and severity of these types of hydrogen-related incidents could increase with HEFA processing.

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[129] *Id.*

[130] Process Safety Integrity *Refining Incidents;* accessed Feb–Mar 2021; available for download at: https://processsafetyintegrity.com/incidents/industry/refining. Appended hereto as Attachment 32.

3.2.3 The DEIR does not disclose or evaluate the limited effectiveness of current and proposed safeguards against hydrogen-related hazards that the project could worsen

Refiners have the ability to use extra hydrogen to quench, control, and guard against runaway reactions, a measure which has proved partially effective and appears necessary for hydro-conversion processing to remain profitable. As a safety measure, however, it has proved ineffective so often that hydro-conversion reactors are equipped to depressurize rapidly to flares.[131] [132] And that last-ditch safeguard, too, has repeatedly failed to prevent catastrophic incidents. The Richmond and Martinez refineries were equipped to depressurize to flares, for example, during the 1989, 1997, 1999 and 2012 incidents described above.[133]

3.2.4 The DEIR does not disclose or evaluate available site-specific data informing the frequency with which hydrogen-related hazards of the project could manifest

In fact, precisely because it is a last-ditch safeguard, to be used only when all else fails, flaring reveals how frequently these hazards manifest as potentially catastrophic incidents. Despite current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the Phillips 66 Rodeo and Marathon Martinez refineries frequently.

Table 8 summarizes specific examples of causal analysis reports for significant flaring which show that hydrogen-related hazard incidents occurred at the refineries a combined total of 100 times from January 2010 through December 2020. This is a conservative estimate, since incidents can cause significant impact without causing environmentally significant flaring. Nevertheless, it represents, on average, and accounting for the Marathon plant closure since 28 April 2020, a hydrogen-related incident frequency at one of these refineries every 39 days.[134]

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[131] Robinson and Dolbear, 2007 (Att. 30).
[132] Chan, 2020 (Att. 29).
[133] Karras, 2021a (Att. 2).
[134] *Id.*; and BAAQMD *Causal Analysis Reports for Significant Flaring*; Bay Area Air Quality Management District: San Francisco, CA. Reports submitted by Phillips and former owners of the Phillips 66 San Francisco Refinery at Rodeo, and submitted by Marathon and formers owners of the Marathon Martinez Refinery, pursuant to BAAQMD Regulation 12-12-406. Appended hereto as Attachment 33;

Table 8. Examples from 100 hydrogen-related process hazard incidents at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020.

Date [a]	Refinery	Hydrogen-related causal factors reported by the refiner [a]
3/11/10	Rodeo	A high-level safety alarm during a change in oil feed shuts down Unit 240 hydrocracker hydrogen recycle compressor 2G-202, forcing the sudden shutdown of the hydrocracker
5/13/10	Martinez	A hydrotreater charge pump bearing failure and fire forces #3 HDS hydrotreater shutdown [b]
9/28/10	Martinez	A hydrocracker charge pump trip leads to a high temperature excursion in hydrocracker reactor catalyst beds that forces sudden unplanned hydrocracker shutdown [c]
2/17/11	Martinez	A hydrogen plant fire caused by process upset after a feed compressor motor short forces the hydrogen plant shutdown; the hydrocracker shuts down on sudden loss of hydrogen
9/10/12	Rodeo	Emergency venting of hydrogen to the air from one hydrogen plant to relieve a hydrogen overpressure as another hydrogen plant starts up ignites in a refinery hydrogen fire
10/4/12	Rodeo	A hydrocracker feed cut due to a hydrogen makeup compressor malfunction exacerbates a reactor bed temperature hot spot, forcing a sudden hydrocracker shutdown [d]
1/11/13	Martinez	Cracked, overheated and "glowing" hydrogen piping forces an emergency hydrogen plant shutdown; the loss of hydrogen forces hydrocracker and hydrotreater shutdowns
4/17/15	Martinez	Cooling pumps trip, tripping the 3HDS hydrogen recycle compressor and forcing a sudden shutdown of the hydrotreater as a safety valve release cloud catches fire in this incident [e]
5/18/15	Rodeo	A hydrocracker hydrogen quench valve failure forces a sudden hydrocracker shutdown [f]
5/19/15	Martinez	A level valve failure, valve leak and fire result in an emergency hydrotreater shutdown
3/12/16	Rodeo	A Unit 240 level controller malfunction trips off hydrogen recycle compressor G-202, which forces an immediate hydrocracker shutdown to control a runaway reaction hazard [g]
1/22/17	Martinez	An emergency valve malfunction trips its charge pump, forcing a hydrocracker shutdown
5/16/19	Martinez	A recycle compressor shutdown to fix a failed seal valve forces a hydrocracker shutdown [h]
6/18/19	Martinez	A control malfunction rapidly depressurized hydrogen plant pressure swing absorbers
11/11/19	Rodeo	A failed valve spring shuts down hydrogen plant pressure swing absorbers in a hydrogen plant upset; the resultant loss of hydrogen forces a sudden hydrotreater shutdown [i]
2/7/20	Martinez	An unprotected oil pump switch trips a recycle compressor, shutting down a hydrotreater
3/5/20	Rodeo	An offsite ground fault causes a power sag that trips hydrogen make-up compressors, forcing the sudden shutdown of the U246 hydrocracker [j]
10/16/20	Rodeo	A pressure swing absorber valve malfunction shuts down a hydrogen plant; the emergency loss of hydrogen condition results in multiple process unit upsets and shutdowns [k]

a. Starting date of the environmentally significant flaring incident, as defined by Bay Area Air Quality Management District Regulations § 12-12-406, which requires causal analysis by refiners that is summarized in this table. An incident often results in flaring for more than one day. The 100 "unplanned" hydro-conversion flaring incidents these examples illustrate are provided in Attachment 33 (*see* Att. 2 for list). Notes b–k below further describe some of these examples with quotes from refiner causal reports. **b.** "Flaring was the result of an 'emergency' ... the #3 HDS charge pump motor caught fire ... ." **c.** "One of the reactor beds went 50 degrees above normal with this hotter recycle gas, which automatically triggered the 300 lb/minute emergency depressuring system." **d.** "The reduction in feed rates exacerbated an existing temperature gradient ...higher temperature gradient in D-203 catalyst Bed 4 and Bed 5 ... triggered ... shutdown of Unit 240 Plant 2." **e.** "Flaring was the result of an Emergency. 3HDS had to be shutdown in order to control temperatures within the unit as cooling water flow failed." **f.** "Because hydrocracking is an exothermic process ... [t]o limit temperature rise... [c]old hydrogen quench is injected into the inlet of the intermediate catalyst beds to maintain control of the cracking reaction." **g.** "Because G-202 provides hydrogen quench gas which prevents runaway reactions in the hydrocracking reactor, shutdown of G-202 causes an automatic depressuring of the Unit 240 Plant 2 reactor ... ." **h.** "Operations shutdown the Hydrocracker as quickly and safely as possible." **i.** "[L]oss of hydrogen led to the shutdown of the Unit 250 Diesel Hydrotreater." **j.** "U246 shut down due to the loss of the G-803 A/B Hydrogen Make-Up compressors."
k. "Refinery Emergency Operating Procedure (REOP)-21 'Emergency Loss of Hydrogen' was implemented."

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.[135] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[136] In other words, incidents escalated to refinery-level systems involving multiple plants frequently—a foreseeable consequence, given that both hydro-conversion and hydrogen production plants are susceptible to upset when the critical balance of hydrogen production supply and hydrogen demand between them is disrupted suddenly. In four of these incidents, consequences of underlying hazards included fires in the refinery.[137]

3.2.5 <u>The DEIR did not identify significant hydrogen-related process hazard impacts that could result from the project</u>

Since switching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents, and flaring has proven unable to prevent every incident from escalating to catastrophic proportions, catastrophic consequences of HEFA process hazards are foreseeable.[138] The DEIR did not identify, evaluate, or mitigate these significant potential impacts of the project.

3.2.6 <u>The DEIR did not identify or evaluate the potential for deferred mitigation of process hazards to foreclose currently feasible hazard prevention measures</u>

As the U.S. Chemical Safety Board found in its investigation of the 2012 Richmond refinery fire: "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating. Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts."[139] Thus, licensing or building the project without first specifying inherently safer features to be built into it has the potential to render currently feasible mitigation measures infeasible at a later date. The DEIR does not address this potential. Examples of specific inherently safer measures which the DEIR could have but did not identify or analyze as mitigation for project hazard impacts include, but are not limited to, the following:

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[135] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 33).
[136] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 33).
[137] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 33).
[138] Karras, 2021a (2021).
[139] CSB, 2015 (Att. 7).

Feedstock processing hazard condition. The County could adopt a project condition to forgo or minimize the use of particularly high process hydrogen demand feedstocks. Since increased process hydrogen demand would be a causal factor for the significant process hazard impacts (§§ 3.2.1–3.2.5) and some HEFA feedstocks increase process hydrogen demand significantly more than other others (§§ 1.2.2, 1.3.1), avoiding feedstocks with that more hazardous processing characteristic would lessen or avoid the hazard impact.

Product slate processing hazard condition. The County could adopt a project condition to forgo or minimize particularly high-process hydrogen demand product slates. Minimizing or avoiding HEFA refining to boost jet fuel yield, which significantly increases hydrogen demand (§§ 1.2.1, 1.2.2), would thereby lessen or avoid further intensified hydrogen reaction hazard impacts.

Hydrogen input processing hazard condition. The County could adopt a project condition to limit hydrogen input per barrel, which could lessen or avoid the process hazard impacts from particularly high-process hydrogen demand feedstocks, product slates, or both.

Hydrogen backup storage processing hazard condition. The County could adopt a project condition to store hydrogen onsite for emergency backup use. This would lessen or avoid hydro-conversion plant incident impacts caused by the sudden loss of hydrogen inputs when hydrogen plants malfunction, a significant factor in escalating incidents as discussed in §§ 3.2.1 and 3.2.4.

Rather than suggesting how or whether the subject project hazard impact could adequately be mitigated, the examples illustrate that the DEIR could have analyzed mitigation measures that are feasible now, and whether deferring those measures might render them infeasible later.

3.3 **Uncertain Degree of Project Safety Oversight**

Of additional concern, it is not clear at present whether the process safety requirements currently applicable to petroleum refineries in California will be fully applicable requirements applied to the proposed biofuel refinery, and the DEIR does not disclose this uncertainty.

CONCLUSION: There is a reasonable potential for the proposed changes in refinery feedstock processing to result in specific hazard impacts involving hydro-conversion processing, including explosion and uncontrolled refinery fire, in excess of those associated with historic petroleum crude refining operations. The DEIR did not identify, evaluate, or mitigate these significant process hazard impacts that could result from the project.

4. AIR QUALITY AND HAZARD RELEASE IMPACTS OF PROJECT FLARING THAT AVAILABLE EVIDENCE INDICATES WOULD BE SIGNIFICANT ARE NOT IDENTIFIED, EVALUATED, OR MITIGATED IN THE DEIR

For the reasons discussed above, the project would introduce new hazards that can be expected to result in new hazard incidents that involve significant flaring, and would be likely increase the frequency of significant flaring. Based on additional available evidence, the episodic releases of hazardous materials from flares would result in acute exposures to air pollutants and significant impacts. The DEIR does not evaluate the project flaring impacts or their potential significance and commits a fundamental error which obscures these impacts.

4.1 The DEIR Did Not Evaluate Environmental Impacts of Project Flaring

Use of refinery flare systems—equipment to rapidly depressurize process vessels and pipe their contents to uncontrolled open-air combustion in flares—is included in the project.[140] The DEIR acknowledges this use of flaring to partially mitigate process hazard incidents[141] and that the flares emit combusted gases.[142] However, the DEIR does not discuss potential environmental impacts of project flaring anywhere in its 628 pages. The DEIR does not disclose or mention readily available data showing frequently recurrent significant flaring at the refinery that is documented and discussed in §3.2.4 above, or any other site-specific flare impact data. This represents an enormous gap in its environmental analysis.

4.2 The DEIR Did Not Identify, Evaluate, or Mitigate Significant Potential Flare Impacts That Could Result from the Project

Had the DEIR assessed available flare frequency, magnitude and causal factors information, the County could have found that project flaring impacts would be significant, as discussed below.

4.2.1 <u>The DEIR did not consider incidence data that indicate the potential for significant project flaring impacts</u>

Flaring emits a mix of many toxic and smog forming air pollutants—particulate matter, hydrocarbons ranging from polycyclic aromatics to methane, sulfur dioxide, hydrogen sulfide, and others—from partially burning off enormous gas flows. Most of the 100 significant flaring incidents documented and described in subsection 3.2.4 above flared more than two million

140 DEIR p. 3-29.
141 DEIR pp. 3-15, 3-17.
142 DEIR p. 3-17.

standard cubic feet (SCF) of vent gas each, and many flared more than ten million SCF.[143] The plumes cross into surrounding communities, where people experience acute exposures to flared pollutants repeatedly, at levels of severity and at specific locations which vary with the specifics of the incident and atmospheric conditions at the time when flaring recurs.

In 2005, flaring was linked to episodically elevated localized air pollution by analyses of a continuous, flare activity-paired, four-year series of hourly measurements in the ambient air near the fence lines of four Bay Area refineries.[144] By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.[145] [146] These same significance thresholds were used to require Phillips 66 and Marathon to report the flare incident data described in subsection 3.2.4 and in this subsection above.[147] [148]

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the Phillips 66 Rodeo and Marathon Martinez refineries *individually* exceeded a relevant significance threshold for air quality. New hazard incidents, and hence flare incidents, can be expected to result from repurposing the same process units that flared without removing the underlying causes for that flaring, which is what implementing the project would do.[149] Consequently, the proposed project can be expected to result in significant episodic air pollution impacts.

4.2.2 <u>The DEIR did not consider causal evidence that indicates project flare incident rates have the potential to exceed those of historic petroleum crude refining</u>

Further, the project would do more than repurpose the same process units that flare without removing the underlying causes for that flaring. The project would switch to new and very different feeds with new corrosion and mechanical integrity hazards, new chemical hydrogen

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143 Karras, 2021a (Att. 2).
144 Karras and Hernandez, 2005. *Flaring Hot Spots: Assessment of episodic local air pollution associated with oil refinery flaring using sulfur as a tracer;* Communities for a Better Environment: Oakland and Huntington Park, CA. Appended hereto at Attachment 34.
145 Ezersky, 2006. *Staff Report: Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* 3 March 2006. Planning and Research Division, Bay Area Air Quality Management District: San Francisco, CA. <u>*See*</u> *esp.* pp. 5–8, 13, 14. Appended hereto as Attachment 35.
146 BAAQMD Regulations, § 12-12-406. Bay Area Air Quality Management District: San Francisco, CA. <u>*See*</u> Regulation 12, Rule 12, at: https://www.baaqmd.gov/rules-and-compliance/current-rules
147 *Id.*
148 BAAQMD *Causal Reports for Significant Flaring* (Att. 33).
149 Section 3 herein; Karras, 2021a (Att. 2).

demands and extremes in reaction heat runaways, in processes and systems prone to potentially severe damage from these very causal mechanisms; damage it would attempt to avoid by flaring. See Section 3. It is thus reasonably likely that compared with historic crude refining, the new HEFA process hazards might more frequently manifest in refinery incidents (*Id.*), hence flaring.

4.2.3 The DEIR did not assess flare impact frequency, magnitude, or causal factors

As stated, the DEIR does not discuss potential environmental impacts of project flaring. It does not disclose, discuss, evaluate or otherwise address any of the readily available data, evidence or information described in this subsection (§ 4.2).

4.3 An Exposure Assessment Error in the DEIR Invalidates its Impact Conclusion and Obscures Project Flare Impacts

A fundamental error in the DEIR obscures flare impacts. The DEIR ignores acute exposures to air pollution from episodic releases entirely to conclude that air quality impacts from project refining would not be significant based only on long-term annual averages of emissions.[150] The danger in the error may best be illustrated by example: The same mass of hydrogen sulfide emission into the air that people nearby breathe without perceiving even its noxious odor when it is emitted continuously over a year can kill people *in five minutes* when that "annual average" emits all at once in an episodic release.[151] Acute and chronic exposure impacts differ.

4.3.1 The DEIR air quality analysis failed to consider the environmental setting of the project

An episodic refinery release can cause locally elevated ambient air pollution for hours or days with little or no effect on refinery emissions averaged over the year. At the same time, people in the plume released cannot hold their breath more than minutes and can experience toxicity due to inhalation exposure. In concluding the project would cause no significant air quality impact without considering impacts from acute exposures to episodic releases, the DEIR did not properly consider these crucial features of the project environmental setting.

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[150] DEIR pp. 4.3-52 through 4.3-56 and 4.3-69 through 4.3-72. See also pp. 3-37 through 3.39.

[151] Based on H_2S inhalation thresholds of 0.025–8.00 parts per million for perceptible odor and 1,000–2,000 ppm for respiratory paralysis followed by coma and death within seconds to minutes of exposure. See Sigma-Aldrich, 2021. *Safety Data Sheet: Hydrogen Sulfide;* Merck KGaA: Darmstadt, DE. Appended hereto as Attachment 36.

4.3.2 The DEIR air quality analysis failed to consider toxicological principles and practices

The vital need to consider both exposure concentration and exposure duration has been a point of consensus among industrial and environmental toxicologists for decades. This consensus has supported, for example, the different criteria pollutant concentrations associated with a range of exposure durations from 1-hour to 1-year in air quality standards that the DEIR itself reports.[152] Rather than providing any factual support for concluding impacts are not significant based on analysis that excludes acute exposures to episodic releases, the science conclusively rebuts that analytical error in the DEIR.

4.3.3 The DEIR air quality analysis failed to consider authoritative findings and standards that indicate project flaring would exceed a community air quality impact threshold

Crucially, the Bay Area Air Quality Management District adopted the significance threshold for flaring discussed above based on *one-hour* measurements and modeling of flare plumes, which, it found, "show an impact on the nearby community."[153] On this basis the District further found that its action to adopt that significance threshold "will lessen the emissions impact of flaring on those who live and work within affected areas."[154] Thus the factual basis for finding flaring impacts significant is precisely the evidence that the DEIR ignores in wrongly concluding that project refining impacts on air quality are not significant.

CONCLUSION: The project is likely to result in a significant air quality impact associated with flaring, and has reasonable potential to worsen this impact compared with historic petroleum crude refining operations at the site. The DEIR does not identify, evaluate, or analyze measures to lessen or avoid this significant potential impact.

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[152] DEIR pp. 4.3-37, 4.3-38; tables 4.3-1, 4.3-2.
[153] Ezersky, 2006 (Att. 35).
[154] *Id.*

5. THE DEIR OBSCURES THE SIGNIFICANCE OF PROJECT IMPACTS BY ASSERTING AN INFLATED ALTERNATIVE BASELINE WITHOUT FACTUAL SUPPORT

Finding the San Francisco Refining Complex (SFC)[155] emitted at lower than historic rates in 2020, the DEIR compares project impacts with near-term future conditions based on historic emissions.[156] Its baseline does not represent existing conditions when the project was proposed; it looks backward for snapshots of historic conditions to compare with project impacts.

The DEIR argues that its backward-looking baseline better represents future conditions than 2020 due to COVID-19.[157] But it provides no factual support for assuming that COVID-19 caused all of the SFC crude rate cut in 2020, or that the past represents the future. The DEIR baseline analysis does not disclose, accurately describe, or evaluate available evidence that a worsening crude supply limitation, unique to the SFC, forced it to cut feed rate. As a result the DEIR compares project impacts with an inflated baseline, which obscures the significance of project impacts, and causes its environmental impacts evaluation to be inaccurate.

5.1 The DEIR Baseline Analysis Does Not Provide or Evaluate a Complete or Accurate Description of the Unique SFC Configuration and Setting Which Affect Baseline Operations by Creating a Unique Feedstock Supply Limitation

5.1.1 The DEIR baseline analysis provides an incomplete, inaccurate and misleading description of the unique physical SFC configuration, its unique geographic setting, and its resultant limited access to petroleum resources for refinery feedstock

The DEIR does not disclose, evaluate, or accurately describe the functional interdependence of SFC components, their unique geography, and the resultant unique limitations in accessible crude feedstock for the SFC. Map 1 illustrates the unique geographic distribution of SFC components in relation to the landlocked crude resources that the SFC was uniquely designed to access for feedstock.[158] The Rodeo Refining Facility (RF) of the SFC ("A" in Map 1) receives most of its oil feed as crude from San Joaquin Valley oilfields ("E") that is blended with, and crucially, thinned by, oils processed in its Santa Maria Refining Facility (SMF) ("B") from crude that its pipeline system collects from offshore ("C") and onshore ("D") Central Coast oilfields.

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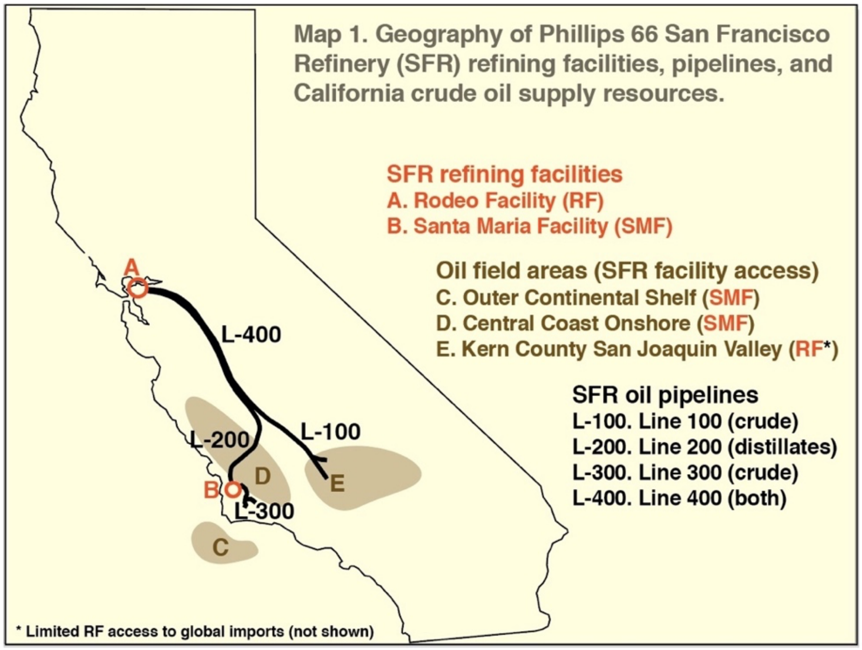
[155] The San Francisco Refining Complex (SFC) includes its Rodeo Refining Facility (RF), Santa Maria Refining Facility (SMF) and pipelines that feed crude to the SMF and crude blended with semi-refined oil to the RF.
[156] DEIR pp. 3-37 through 3-39; see also pp. 3-21, 5-12. Note that the DEIR picks different historic baseline periods for comparison with refinery (2019) and marine vessel (2017–2019) emissions.
[157] *Id.*
[158] Map 1 is only approximately to scale, but otherwise consistent with facility and pipeline maps in the DEIR.



The SMF ("B") has no seaport access to import foreign or Alaskan crude via marine vessels[159] which other refineries rely on for most of the crude refined statewide.[160] It receives crude only via its locally-connected pipeline, limiting its access to crude from outside the local area almost entirely.[161] Onshore oilfields in San Luis Obispo, northern Santa Barbara and southern Monterey counties ("D") feed the SMF through the local pipeline system, either via other local pipelines connected to it or via trucks unloading into a pump station, which is limited to roughly half of the SMF capacity.[162] Outer Continental Shelf (OCS) oilfields off northern Santa Barbara County supplied up to 85% of SMF crude as of 2014,[163] but that 85% came from only a few OCS fields ("C") which had pipeline connections to the local SMF pipeline system ("L-300").[164]

The DEIR does not disclose the lack of SMF seaport access—which crucially limits its feed access almost entirely to local OCS and onshore crude—then obscures the larger effect of this on

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[159] SLOC, 2014. *Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report;* prepared for San Luis Obispo County (SLOC) by Marine Research Specialists (MRS). October 2014. SCH# 2013071028. Excerpt including title page and project description. Appended hereto as Attachment 37.
[160] *Crude Oil Sources for California Refineries;* California Energy Commission: Sacramento, CA. (CEC, 2021a). Appended hereto as Attachment 38.
[161] SLOC, 2014 (Att. 37).
[162] *Id.*
[163] *Id.*
[164] These OCS oilfields that the SMF could historically or currently access via pipelines are the Point Pedernales, Point Arguello, Hondo, Pescado, and Sacate fields. <u>*See*</u> BOEM, 2021b (map appended hereto as Attachment 44).

the project baseline through clear error in its setting description. SFC pipeline system Line 100 ("L-100" in Map 1) runs from Kern County oilfields in the San Joaquin Valley ("E") north to the junction with Line 200 from the SMF and Line 400 to the RF, where the Kern crude and semi-refined SMF output flow north through Line 400 to the RF.[165] But the DEIR describes Line 100 as directly supplying the SMF: "Two other pipelines—Line 100 and Line 300—*connect the Santa Maria Site* to crude oil collection facilities elsewhere in California ... [including] Kern County ... ." DEIR at 3-21 (*emphasis added*). This clear error in the DEIR obscures the fact that the SMF lacks economic access to San Joaquin oilfields—and further obscures the mix of oils flowing through Line 400 to the RF.

These existing conditions in the project setting that the DEIR omits or describes inaccurately have a profound systemic effect on the project baseline. Instead of pipeline access to the largest regional crude resource in California[166] as the DEIR wrongly describes, the SMF lacks both that access, and seaport access to imports that provide the largest source of crude refined statewide,[167] which the DEIR also fails to disclose. That doubly limited access makes SMF operations exceptionally vulnerable to loss of local crude supply. The systemic effect has to do with how changes in the mix of San Joaquin Valley crude and semi-refined oils from the SMF flowing to the RF—that mix in the pipe to the RF being a fact the error in the DEIR described above also obscures—could limit crude supply for the RF.

The DEIR states that the entire pipeline system would shutter in place when the SMF closes, providing that conclusion as a reason for the "transitional" increase in permitted crude inputs to the RF through its marine terminal. It further concludes that continued crude refining would be infeasible at the RF if the RF loses access to crude and semi-refined oils from the SMF and pipeline system.[168] Although the DEIR does not explain this, a reason the pipeline system may not continue to function after closure of the SMF is that lines 100 and 400 cannot physically

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[165] Careful review of DEIR Figure 3-5 confirms this description of pipeline flows, once the reader knows that crude *does not* flow to the SMF through Line 200. Without knowing that, however, the erroneous assertion in the text on page 3-21 of the DEIR and its Figure 3-5 can only be viewed to make sense together by assuming the opposite.
[166] San Joaquin Valley extraction in District 4 (Kern, Tulare, and Inyo counties) comprised 71% of California crude extracted, 445% more than any other oil resource district in the state, in 2017. <u>*See*</u> DOGGR, 2017. *2017 Report of California Oil and Gas Production Statistics;* California Department of Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. Appended hereto as Attachment 39.
[167] CEC, 2021a (Att. 38).
[168] DEIR p. 5-3.

function effectively without input from the SMF. The less viscous SMF output[169] thins the viscous (thick like molasses) San Joaquin Valley Heavy crude ("E" in Map 1), enabling it to move efficiently through Line 400 ("L-400") to the RF. Loss of SMF feed input and hence Line 400 thinning oil could effectively *disable* the pipeline feedstock supply for the RF. This is the profound systemic effect that severely limited SMF access to crude could cause.

Thus, the exceptional vulnerability to local crude supply loss described above is a critical condition affecting the SMF, RF, and entire San Francisco Refining Complex.

No other California refinery is built to access isolated crude resources for its feed with land-locked front-end refining hundreds of pipeline miles from its back-end refining, and no other faces the feed supply crisis this built-in reliance on geographically limited and finite resources has wrought. The DEIR does not disclose or evaluate this crisis in its baseline analysis.

5.2 The DEIR Baseline Analysis Does Not Disclose or Evaluate Actions by the Refiner and Others Which Demonstrate Their Concerns that Feedstock Supply Limitations Could Affect Near Term Future Refinery Operating Conditions

Actions by Phillips 66 and others prior to and outside the project review demonstrated their concerns that the feedstock supply limitation discussed above could affect near-term future operating conditions. The DEIR does not disclose or evaluate the actions discussed below.

5.2.1 <u>Phillips 66 action to expand marine vessel imports warned of refinery curtailment risk</u>

On 6 September 2019 Carl Perkins, then the Phillips 66 Rodeo Facility manager, wrote Jack Broadbent, the Executive Director of the Bay Area Air Quality Management District, offering "concessions" in return for advancing a proposal by the refiner to increase crude and gas oil imports to the RF via marine vessels.[170] Perkins stated that proposal—which was never approved or implemented—would "greatly enhance the continued viability of the Rodeo Refinery if and when California-produced crude oil becomes restricted in quantity or generally unavailable as a refinery process input."[171] Perkins further stated that the refiner "seeks to ensure

[169] Naphtha, distillates and gas oil ("pressure distillate") from crude accessed and partially refined by the SMF, then sent through lines 200 and 400 to the RF for gasoline, diesel, and jet fuel production.
[170] Perkins, 2019. Phillips 66 correspondence regarding Bay Area Air Quality Management District Permit Application No. 25608. Appended hereto as Attachment 40.
[171] *Id.*

a reliable crude oil supply for the future. If this potential process input problem is not resolved, it could lead to processing rate curtailments at the refinery ... ."[172]

5.2.2 Army Engineers proposal to improve access to crude imports by dredging Bay

On 17 May 2019 the U.S. Army Corps of Engineers released a Draft Environmental Impact Statement for its proposal to relieve a shipping bottleneck affecting the Phillips 66 RF and three other refineries that import crude through the San Francisco Bay by dredging to deepen some shipping channels between Richmond to east of Martinez (Avon).[173] Benefits to the refiners from the proposal—which was never approved or implemented—including improved access to crude imports and fuels exports, but excluding the anticipated growth in their petroleum tanker cargoes, could have exceeded $11,300,000 per year.[174]

5.2.3 Phillips 66 action to expand access to crude imports via oil trains

Before its warning to the Bay Area Air Quality Management District described above, and before applying to that air district for expanded crude imports through the RF marine terminal, Phillips 66 sought access to new sources of crude via oil trains which would unload crude imported from other U.S. states and Canada at a proposed new SMF rail spur extension.[175]

5.2.4 San Luis Obispo County review of proposed Phillips 66 SMF rail spur extension

Permits for that rail spur extension were denied and it was never built. In its review of the proposed rail spur, San Luis Obispo County described the limited SMF access to competitively priced crude. Its report previewed, during 2014, the 2019 warning by Phillips 66 described herein above: "Phillips 66 would like to benefit from these competitively priced crudes. In the short-term (three to five years), the availability of these competitively priced crudes would be the main driver ... . Production from offshore Santa Barbara County (OCS crude) has been in decline for a number of years. ... . In the long-term, the ... remaining life of the refinery is dependent on crude oil supplies, prices and overall economics."[176]

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172 *Id.*

173 ACOE, 2019, Draft Integrated General Reevaluation Report and Environmental Impact Statement, San Francisco Bay to Stockton, California Navigation Study. Army Corps of Engineers: Jacksonville, FL. EIS and Appendix D to EIS. Appended hereto as Attachment 41. *See* pp. ES-3, D-22, D-24, maps.

174 *Id.*

175 SLOC, 2014 (Att. 37).

176 *Id.*

Other more recent actions, which the DEIR likewise does not disclose or evaluate, suggest that the lack of access to crude has now become acute for the SMF. By 2017, ExxonMobil proposed to temporarily truck crude to the SMF, a proposal that the Santa Barbara County Planning Commission later voted to deny.[177] Finally, Phillips 66 abandoned its proposed SMF pipeline replacement project in August 2020.[178] This fact strongly suggests that the company's plan to decommission the SMF was developed independently from the subject project, and was already underway before Phillips 66 filed its Application for the project with the County.

5.3 The DEIR Does Not Disclose or Evaluate Available Data and Information That Confirm the Crude Supply Limitation Affects Current SFC Operating Conditions and Strongly Suggest the Potential for Near Term SFC Facilities Closure

Abundant relevant data that the DEIR did not disclose or evaluate have been reported publicly by the state and federal governments. Together with the data and information provided herein above, these data support findings that available evidence indicates crude supply limitations have forced SFC refining rates below historic pre-2020 conditions, and that the SFC would be more likely to shutter crude refining operations in the near future than return to and maintain historic refining rates. Had the DEIR properly disclosed and evaluated this evidence, the County could have found that the comparison in the DEIR of project impacts with impacts caused at historic refining rates is unsupported, and inaccurate.

5.3.1 <u>Federal crude extraction data pertinent to the project baseline confirm a sharp decline in the major historic source of crude refined by the SMF</u>

Chart 3 illustrates U.S. Bureau of Ocean Energy Management (BOEM) crude production data[179] for OCS oilfields that the SMF historically and currently could access via pipelines connected to the local SMF pipeline system.[180] Crude production from OCS oilfields that historically supplied the vast majority of SMF crude feed (§ 5.1.1) continued in steep long-term decline after the 2014 San Luis Obispo County analysis (§ 5.2.4). *See* Chart 3.

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[177] SBC, 2021. *ExxonMobil Interim Trucking for SYU Phased Restart Project Status, Description, Timeline;* Santa Barbara County Department of Planning & Development. Website page accessed 18 November 2021. Appended hereto as Attachment 42.
[178] Scully, J., 2020. Phillips 66 Plans 2023 Closure of Santa Maria Refinery, Pulls Application for Pipeline Project. https://www.noozhawk.com/article/phillips_66_closure_of_santa_maria_refinery_planned_for_2023_20200813
[179] BOEM, 2021a. U.S. Bureau of Ocean Energy Management. *Pacific Production;* data Pacific OCS Region data, 1996–2021. https://www.data.boem.gov/Main/PacificProduction.aspx#ascii. Appended hereto as Attachment 43.
[180] BOEM, 2021b. U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement/Bureau of Ocean Energy Management, Pacific OCS Region. Map updated May 2021. Appended hereto as Attachment 44.

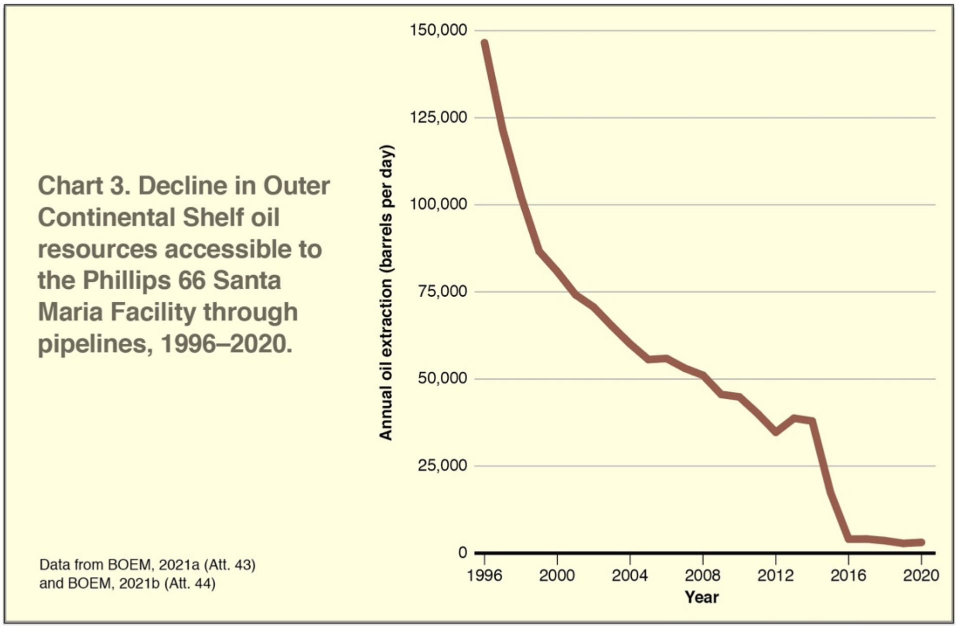


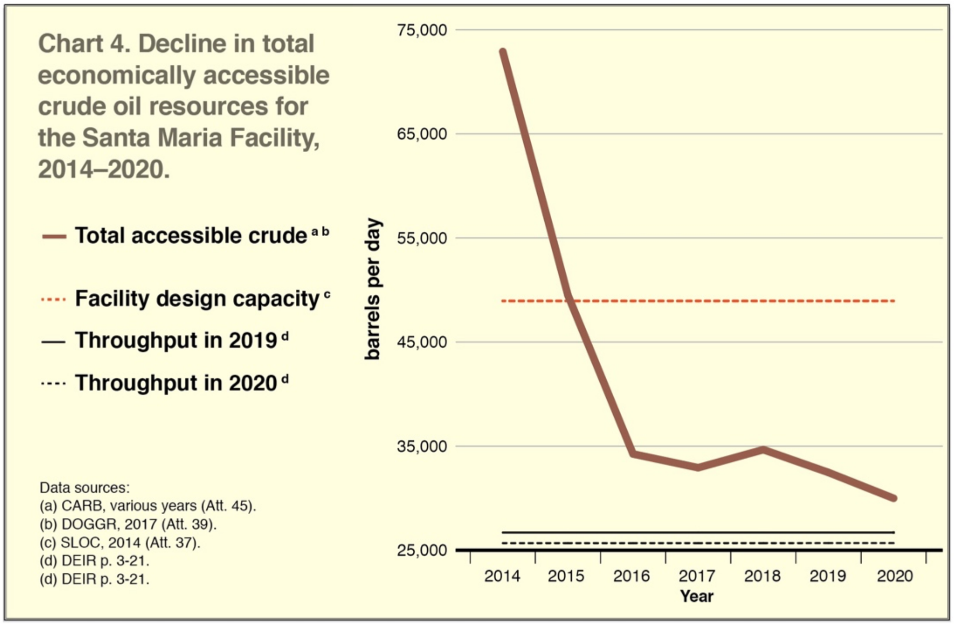
Chart 3. Decline in Outer Continental Shelf oil resources accessible to the Phillips 66 Santa Maria Facility through pipelines, 1996–2020.

From an annual average of approximately 146,000 b/d in 1996, OCS oil production in these oilfields,[181] collectively, fell by 98% to approximately 3,000 b/d in 2020.[182]

5.3.2 <u>State crude refining data pertinent to the project baseline confirm that declining access to crude feedstock forced SFC refining rates below historic rates and, together with other relevant available data, strongly suggest the potential for the crude refinery to shutter</u>

The California Air Resources Board (CARB)[183] and Geologic Energy Management Division (CalGEM, formerly DOGGR)[184] each collected data that in combination quantify and locate the annual amounts of crude refined in California from each OCS and State offshore and onshore oilfield. Chart 4 illustrates these state data for the annual volumes of crude refined in California which were derived from OCS and onshore oilfields that the SMF can access.[185]

[181] These OCS oilfields that the SMF could historically or currently access via pipelines are the Point Pedernales, Point Arguello, Hondo, Pescado, and Sacate fields. <u>*See*</u> BOEM, 2021b (Att. 44).
[182] BOEM, 2021a (Att. 43).
[183] CARB, various years. *Calculation of Crude Average Carbon Intensity Values;* California Air Resources Board: Sacramento, CA. *In* LCFS Crude Oil Life Cycle Assessment, Final California Crude Average Carbon Intensity Values. Accessed October 2021. https://ww2.arb.ca.gov/resources/documents/lcfs-crude-oil-life-cycle-assessment. Appended hereto as Attachment 45.
[184] DOGGR, 2017 (Att. 39).
[185] Based on evidence described in §§ 5.1 and 5.2 herein, Chart 4 includes all onshore and State offshore fields identified by DOGGR, 2017 (Att. 46) in District 3, and OCS oilfields included in Chart 3 as noted above, and optimistically assumes that no other California refiner competes for access to their production.



The falling brown curve in Chart 4 illustrates the rapid decline in total crude accessible to the SMF that was refined statewide since 2014. Most importantly, its fall below the dashed red line indicates that this dwindling crude supply could no longer support Santa Maria Facility operation at or even near its design capacity.

From approximately 73,000 b/d in 2014, total refining of Central Coast onshore, offshore, and OCS crude accessible to the SMF via truck and pipeline fell by 59%, to approximately 30,000 b/d in 2020.[186]

In 2019, before COVID-19, the SMF was operating at only 26,700 b/d,[187] 45% below its 48,950 b/d capacity.[188] [189] In 2020, as accessible crude fell by roughly another 2,000 b/d,[190] the SMF cut rate by another 1,000 b/d to 25,700 b/d,[191] fully 47% below its design capacity.

[186] CARB, various years (Att. 45); DOGGR, 2017 (Att. 39).
[187] DEIR p. 3-21.
[188] SLOC, 2014 (Att. 37).
[189] This very low SMF refining rate in 2019 reduced SMF output to the RF and likely reduced its capacity to thin and enable movement of viscous San Joaquin Valley crude through Line 400 to the RF. The County could have evaluated this likelihood had it requested the data to do so from Phillips 66 as necessary for project review.
[190] CARB, various years (Att. 45); DOGGR, 2017 (Att. 39).
[191] DEIR p. 3-21.

5.3.3 Baseline analysis errors in the DEIR inflated the project baseline, obscured the significance of project impacts in comparison with that inflated baseline, and resulted in a deficient environmental impacts evaluation

As stated, its errors and omissions resulted in the DEIR comparing project impacts with those from refining crude at a greater rate than observed when the project was proposed and a greater rate than the SFC can reasonably be expected to reach and maintain in the near future. Comparing project impacts with this inflated baseline artificially reduced the significance of project impacts it predicted. This erroneously reduced the significance of DEIR impact findings.

5.4 The DEIR No Project Analysis Commits a Categorical Error that Conflates the Crude Supply Limitation with Fuel Supply Limits Irrelevant to Project Baseline

Elsewhere in the DEIR it asserts that decommissioning the refinery is not the "no project" alternative since shuttering the refinery is infeasible at least in part because petroleum fuels market forces would not allow that result. In point of fact the DEIR has it exactly backwards: fuels demand cannot cause a refinery to make fuels when the refinery cannot get the crude to make the fuels due to structural rather than market-based factors. The DEIR commits a categorical error that conflates the causal factor affecting specific baseline conditions with another factor that is irrelevant to these specific conditions because it could not affect them. In other contexts fears that imports and prices could soar without the SCF can be eased by pointing out that statewide refining overcapacity far exceeds its capacity (§ 2.2), but here, the DEIR fuels supply-demand question itself is not relevant to project baseline conditions.

CONCLUSION: The DEIR did not disclose or evaluate abundant evidence that worsening crude supply losses drove the refinery feed rates below historic levels by the time the project was proposed. This evidence further suggests the refinery would be more likely to close than return to and maintain historic crude rates in the near future. Instead of evaluating this evidence, the DEIR concluded that historic conditions it explicitly found to result in more severe impacts than conditions at the time the project was proposed should be compared with potential impacts that could result from the project. Reliance on that factually unsupported and inflated baseline would systematically and artificially reduce the significance of project impacts findings.

CONCLUSIONS

1. The DEIR provides an incomplete, inaccurate, and truncated description of the proposed project. Available information that the DEIR does not describe or disclose will be necessary for sufficient review of environmental impacts that could result from the project.

2. A reasonable potential exists for the project to result in significant climate and air quality impacts by increasing the production and export of California-refined fuels instead of replacing petroleum fuels. This impact would be related to the particular type and use of biofuel proposed. Resultant greenhouse gases and co-pollutants would emit in California from excess petroleum and biofuel refining, and emit in California as well as in other states and nations from petroleum and biofuel feedstock extraction and end-use fuel combustion. The DEIR does not identify, evaluate, or mitigate these significant potential impacts of the project.

3. There is a reasonable potential for the proposed changes in refinery feedstock processing to result in specific hazard impacts involving hydro-conversion processing, including explosion and uncontrolled refinery fire, in excess of those associated with historic petroleum crude refining operations. The DEIR did not identify, evaluate, or mitigate these significant process hazard impacts that could result from the project.

4. The project is likely to result in a significant air quality impact associated with flaring, and has reasonable potential to worsen this impact compared with historic petroleum crude refining operations at the site. The DEIR does not identify, evaluate, or analyze measures to lessen or avoid, this significant potential impact.

5. The DEIR did not disclose or evaluate abundant evidence that worsening crude supply losses drove the refinery feed rates below historic levels by the time the project was proposed. This evidence further suggests the refinery would be more likely to close than return to and maintain historic crude rates in the near future. Instead of evaluating this evidence, the DEIR concluded that historic conditions it explicitly found to result in more severe impacts than conditions at the time the project was proposed should be compared with potential impacts that could result from the project. Reliance on that factually unsupported and inflated baseline would systematically and artificially reduce the significance of project impacts findings.

Attachments List

1. Curriculum Vitae and Publications List

2. Karras, 2021a. *Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing;* prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting. August 2021.

3. Karras. 2021b. *Unsustainable Aviation Fuels: An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel from repurposed crude refineries;* Natural Resources Defense Council (NRDC). Prepared for the NRDC by Greg Karras, G. Karras Consulting.

4. USDOE, 2021. *Renewable Hydrocarbon Biofuels;* U.S. Department of Energy, accessed 29 Nov 2021 at https://afdc.energy.gov/fuels/emerging_hydrocarbon.html

5. Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model.

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7. CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S. Chemical Safety Board: Washington, D.C. https://www.csb.gov/file.aspx?Documentid=5913.

8. API, 2009. *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries;* API Recommended Practice 939-C. First Edition, May 2009. American Petroleum Institute: Washington, D.C.

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14. BAAQMD, 2021. 9 Sep 2021 email from Damian Breen, Senior Deputy Executive Officer – Operations, Bay Area Air Quality Management District, to Ann Alexander, NRDC, regarding Phillips 66 refinery (no. 21359) – possible unpermitted modifications.

15. Kupp, 2020a. Email text and attached site map from Gary Kupp, Contra Costa County, to Charles Davidson, incoming Rodeo-Hercules Fire Protection District director. 2 December 2020.

16. Phillips 66 3Q 2021 Earnings Conference Call; 29 Oct 2021, 12 p.m. ET. Transcript.

17. Weinberg-Lynn, 2021. 23 July 2021 email from Nikolas Weinberg-Lynn, Manager, Renewable Energy Projects, Phillips 66, to Charles Davidson.

18. Bredeson et al., 2010. Factors driving refinery CO_2 intensity, with allocation into products. *Int. J. Life Cycle Assess.* 15:817–826. DOI: 10.1007/s11367-010-0204-3.

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24. USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Inf. Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm

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29. Chan, 2020. *Converting a Petroleum Diesel Refinery for Renewable Diesel;* White Paper / Renewable Diesel. Burns McDonnell. www.burnsmcd.com.

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